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Economic and Benefits Analysis for the Proposed Section 316(b) Phase II Existing Facilities Rule

Economic and Benefits Analysis for the Proposed Section 316(b) Phase II Existing Facilities Rule

U.S. Environmental Protection Agency
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Chapter A1: Introduction and Overview

Introduction

Chapter Contents

EPA is proposing regulations implementing Section 316(b) of the Clean Water Act (CWA) for existing facilities with a design cooling water intake flow of 50 million gallons per day (MGD) or greater (33 U.S.C. 1326(b)). The Proposed Section 316(b) Phase II Existing Facilities Rule would establish national technology-based performance requirements applicable to the location, design, construction, and capacity of cooling water intake structures (CWIS) at existing facilities. The proposed national requirements would establish the best technology available (BTA) to minimize the adverse environmental impact (AEI) associated with the use of these structures. CWIS may cause AEI through several means, including impingement (where fish and other aquatic life are trapped on equipment at the entrance to CWIS) and entrainment (where aquatic organisms, eggs, and larvae are taken into the cooling system, passed through the heat exchanger, and then discharged back into the source water body).

A1-1 Scope of the Proposed Rule

The proposed Phase II rule applies to existing power producing facilities that meet all of the following conditions:

They use a cooling water intake structure or structures, or obtain cooling water by any sort of contract or arrangement with an independent supplier who has a cooling water intake structure; or their cooling water intake structure(s) withdraw(s) cooling water from waters of the U.S., and at least twenty-five (25) percent of the water withdrawn is used for contact or non-contact cooling purposes;

- They have an NPDES permit or are required to obtain one; and
- They have a design intake flow of 50 MGD or greater.

The proposed Phase II rule also covers substantial additions or modifications to operations undertaken at such facilities. While all facilities that meet these criteria are subject to the regulation, this Economic and Benefit Analysis (EBA) focuses on 539 utility and non-utility steam electric power generating facilities identified in EPA's 2000 Section 316(b) Industry Survey as being potentially covered by this proposed rule. These 539 facilities represent 550 facilities nation-wide.[1]

The proposed Phase II rule does not cover (1) new steam electric power generating facilities, (2) new manufacturing facilities, (3) existing steam electric power generating facilities with a design intake flow of less than 50 MGD, and (4) existing manufacturing facilities. The Final Section 316(b) New Facility Rule (Phase I), which EPA promulgated in November 2001, covered new steam electric power generating facilities and new manufacturing facilities. Existing steam electric power generating facilities with a design intake flow of less than 50 MGD and existing manufacturing facilities will be addressed by a separate rule (Phase III).

[1] EPA applied sample weights to the 539 facilities to account for non-sampled facilities and facilities that did not respond to the survey. For more information on EPA's 2000 Section 316(b) Industry Survey, please refer to the Information Collection Request (U.S. EPA, 2000).

A1-2 Definitions of Key Concepts

This EBA presents EPA's analyses of costs, benefits, and potential economic impacts as a result of the proposed Phase II rule. In addition to important economic concepts, which will be presented in the following chapters, understanding this document requires familiarity with a few key concepts applicable to CWA section 316(b) and this regulation. This section defines these key concepts.

- ***Capacity Utilization Rate:*** The ratio between the average annual net generation of the facility (in MWh) and the total net capability of the facility (in MW) multiplied by the number of available hours during a year. The average annual generation must be measured over a five year period (if available) of representative operating conditions.

- ***Cooling Water Intake Structure (CWIS):*** The total physical structure and any associated constructed waterways used to withdraw water from waters of the U.S. The CWIS extends from the point at which water is withdrawn from the surface water source up to, and including, the intake pumps.

- ***Design Intake Flow:*** The value assigned (during the facility's design) to the total volume of water withdrawn from a source waterbody over a specific time period.

- ***Entrainment:*** The incorporation of all life stages of aquatic organisms with intake water flow entering and passing through a CWIS and into a cooling water system (e.g., fish and shellfish).

- ***Existing Facility:*** Existing facility means any facility that commenced construction before January 17, 2002; and
  (1) any modification of such a facility;
  (2) any addition of a unit at such a facility for purposes of the same industrial operation;
  (3) any addition of a unit at such a facility for purposes of a different industrial operation, if the additional unit uses an existing CWIS and the design capacity of the intake structure is not increased; or
  (4) any facility constructed in place of such a facility, if the newly constructed facility uses an existing CWIS whose design intake flow is not increased to accommodate the intake of additional cooling water.

- ***Impingement:*** The entrapment of all life stages of aquatic organisms on the outer part of an intake structure or against a screening device during periods of intake water withdrawal (e.g., fish, shellfish, turtles, birds, seals, etc.).

- ***Phase II Existing Facility:*** An existing facility, as defined above, that also meets the following requirements:
  (1) is a point source that uses or proposes to use a CWIS; and
  (2) both generates and transmits electric power, or generates electric power but sells it to another entity for transmission; and
  (3) has at least one CWIS that uses at least 25 percent of the water it withdraws for cooling purposes; and
  (4) has a design intake flow of 50 MGD or more.
  The category of facilities that would meet the proposed CWIS criteria for Phase II existing facilities are electric power generation utilities and nonutility power producers, including cogeneration facilities.

A1-3 Summary of the Proposed Rule

The Proposed Section 316(b) Phase II Existing Facilities Rule would establish national standards applicable to the location, design, construction, and capacity of CWIS at Phase II existing facilities to minimize AEI. The requirements of the proposed Phase II rule reflect the BTA for minimizing AEI associated with the CWIS based primarily on source water body type and the amount of cooling water withdrawn by a facility. A facility may choose one of three compliance alternatives for meeting BTA requirements under this proposed rule:

- ***Compliance Alternative 1*** allows a facility to demonstrate that its existing CWIS design and construction technologies, operational measures, or restoration measures currently meet the specified performance standards.
- ***Compliance Alternative 2*** allows a facility to select and implement design and construction technologies, operational measures, or restoration measures that satisfy the specified performance standards.
- ***Compliance Alternative 3*** allows a facility to demonstrate that it meets specified compliance cost criteria and obtain a site-specific determination of BTA for minimizing AEI.

A1-3.1 Proposed Performance Standards

The proposed Phase II performance standards are based on several key factors, including CWIS intake capacity, facility capacity utilization rate, source waterbody category, and percentage of the source water being withdrawn. The proposed rule would establish performance standards for three groups of waterbody categories. These include (1) tidal rivers, estuaries, oceans, and the Great Lakes; (2) lakes (other than the Great Lakes) and reservoirs; and (3) freshwater rivers or streams. The performance standards include the following:

- ***Capacity*** – Any Phase II facility that reduces its intake capacity to a level commensurate with that which can be achieved by a closed cycle, recirculating cooling system is not subject to further requirements under the proposed rule. This is applicable to facilities with CWIS located in any of the waterbody categories.
- ***Capacity Utilization Rate*** – Any Phase II facility with a capacity utilization rate that is less than 15 percent must reduce impingement mortality of all life stages of fish and shell fish by 80 to 95 percent from the calculation baseline, regardless of proportional flow level of the facility.
- ***Source Waterbody Category/Proportion of Waterbody*** – These requirements vary according the combination of waterbody category and percentage of the waterbody withdrawn:
  - Facilities with one or more CWIS located in an estuary, tidal river, ocean, or Great Lake must reduce impingement mortality of all life stages of fish and shell fish by 80 to 95 percent from the calculation baseline, <u>and</u> it must reduce entrainment of all life stages of fish and shellfish by 60 to 90 percent from the calculation baseline;
  - Facilities with one or more CWIS located in a freshwater river or stream must reduce impingement mortality of all life stages of fish and shell fish by 80 to 95 percent from the calculation baseline and must reduce entrainment of all life stages of fish and shellfish by 60 to 90 percent from the calculation baseline if they have a design intake flow greater than 5 percent of mean annual flow;
  - Facilities with one or more CWIS located in a freshwater river or stream must reduce impingement mortality of all life stages of fish and shell fish by 80 to 95 percent from the calculation baseline if they have a design intake flow that is 5 percent or less of mean annual flow;
  - Facilities with one or more CWIS located in a lake or reservoir must reduce impingement mortality of all life stages of fish and shell fish by 80 to 95 percent from the calculation baseline. In addition, if such facilities propose to increase design intake flow they must not disrupt the natural thermal stratification or turnover pattern.

Under compliance alternative 1, a Phase II facility could demonstrate present compliance with intake capacity requirements,

impingement reduction, entrainment reduction, and/or thermal stratification requirements, as applicable. These facilities could use existing CWIS design and construction technologies, operational measures, or restoration measures to demonstrate such compliance.

Under compliance alternative 2, an existing facility would have to select and implement design and construction technologies, operational measures, or restoration measures that satisfy the specified performance standards applicable to the facility.

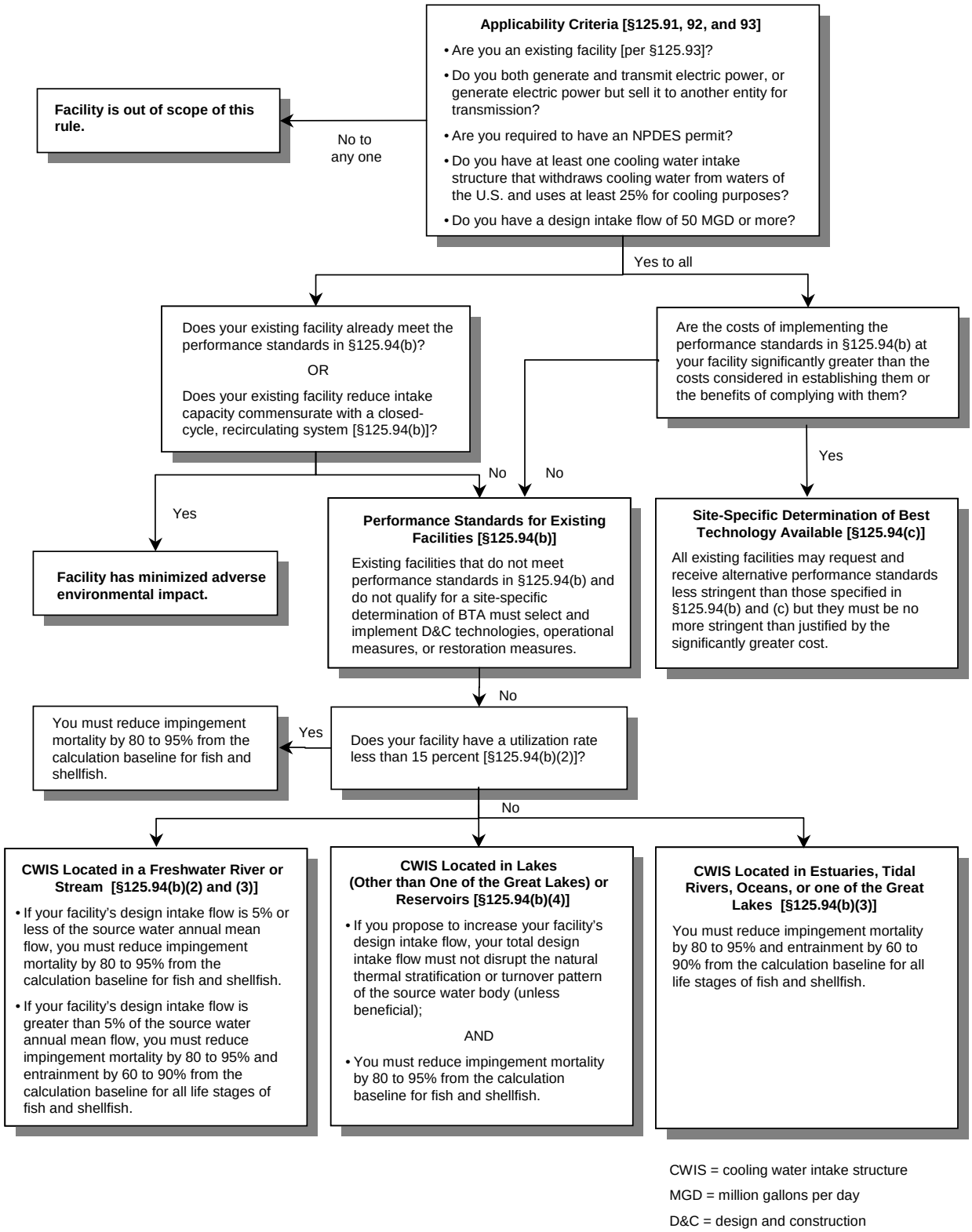
Examples of *technologies that minimize impingement and entrainment (I&E)* and that facilities might install to meet the performance standards of the proposed rule include technologies such as wet cooling towers, fine mesh screens, intake traveling screens, and Gunderbooms that exclude smaller organisms from entering the CWIS; passive intake systems such as wedge wire screens, perforated pipes, porous dikes, and artificial filter beds; and diversion and/or avoidance systems. Examples of *technologies that maximize survival of impinged organisms* include fish handling systems such as bypass systems, fish buckets, fish baskets, fish troughs, fish elevators, fish pumps, spray wash systems, and fish sills. Examples of *operational measures that minimize I&E* include seasonal flow reductions to minimize intake flow during spawning or migrating seasons. The calculation baseline against which compliance with the performance standards should be assessed is a shoreline intake with the capacity to support once-through cooling and no impingement mortality or entrainment controls.

Under compliance alternative 3, a facility must demonstrate that it meets one of two cost tests, and then the Director must make a site-specific determination of BTA for minimizing AEI. The applicant may demonstrate that the costs of compliance with the performance standards applicable to the facility (considering the facility's source water body type and proportional cooling water intake volume) would be significantly greater than (1) the costs considered by the Administrator in developing the rule standards or (2) the benefits of complying with such standards. Facilities that request a site-specific determination of BTA will have individual performance standards established by the Director at the time of permit issuance. The performance standards requested may be less stringent than those specified in the proposed rule, but they may be no less stringent than justified by the significantly greater cost.

Under all three compliance alternatives, the proposed Phase II rule allows the use of restoration measures to maintain the level of fish and shellfish in the water body, including the community structure and function, at a level comparable to that which would be achieved by the implementation of design and construction technologies and operational measures. A facility may opt to combine restoration measures with design and construction technologies and/or operational measures to achieve the desired level of fish and shellfish protection. Among other requirements, the permit applicant must submit a summary of benefits, a narrative of the proposed restoration measures, and a plan for implementing and maintaining the efficacy of the restoration effort to the Director as part of the application.

Figure A1-1 displays the framework for EPA's Proposed Section 316(b) Phase II Existing Facilities Rule.

Figure A1-1: Section 316(b) Phase II Existing Facilities Rule Framework



Source: U.S. EPA analysis, 2002.

A1-4 Summary of Alternative Regulatory Options

EPA also considered a number of other technology-based options for regulating Phase II facilities. As in the proposed option, any technology-based options considered would allow for voluntary implementation of restoration measures by facilities that choose to reduce their intake flow to a level commensurate with the performance requirements of the option. Thus, under these options, facilities would be able to implement restoration measures that would result in increases in fish and shellfish if a demonstration of comparable performance for species of concern is made. Similarly, most technology-based options considered also would allow facilities to request alternative requirements that are less stringent than those specified, but only if the Director determines that data specific to the facility indicate that compliance with the relevant requirement would result in compliance costs significantly greater than (a) the costs EPA considered in establishing the requirement at issue or (b) the benefits of the requirement. The alternative requirement could be no less stringent than justified by the significantly greater cost. Finally, under the technology-based options considered, facilities that operate at less than 15 percent capacity utilization would, as in the proposed option, only be required to have impingement control technologies.

Other regulatory options considered by EPA include:

- (1) requiring Phase II facilities located on different categories of waterbodies to reduce intake capacity commensurate with the use of closed-cycle, recirculating cooling systems based on location and the percentage of the source waterbody they withdraw for cooling (Options 1 and 2);
- (2) requiring all Phase II facilities to reduce I&E to levels established based on the use of design and construction technologies (e.g., fine mesh screens, fish return systems) or operational measures (Option 3a);
- (3) requiring all Phase II facilities to reduce intake capacity commensurate with the use of closed-cycle, recirculating cooling systems (Option 4);
- (4) requiring all Phase II facilities to reduce their intake capacity to a level commensurate with the use of a dry cooling system (Option 5); and
- (5) requiring all Phase II facilities located on certain types of water bodies to reduce intake capacity commensurate with the use of closed-cycle recirculating cooling systems (Option 6).

Each of these alternative regulatory options is briefly described below.

a. Intake capacity commensurate with closed-cycle, recirculating cooling systems based on waterbody type and proportion of waterbody flow (Options 1 and 2)

This option, referred to as the "waterbody/capacity-based option," would require facilities that withdraw very large amounts of water from an estuary, tidal river, or ocean to reduce their intake capacity to a level commensurate with that which can be attained by a closed-cycle, recirculating cooling system. Under this option, EPA would group waterbodies into five categories: (1) freshwater rivers or streams, (2) lakes or reservoirs, (3) Great Lakes, (4) tidal rivers or estuaries, and (5) oceans. The following compliance requirements would apply:

- Two types of facility would have to meet standards for reducing impingement mortality and entrainment based on the performance of wet cooling towers: (1) facilities with CWIS located in a tidal river or estuary, if the intake flow is greater than one percent of the source water tidal excursion and (2) facilities with CWIS located in an ocean, if the intake flow is greater than 500 MGD. In addition, these facilities must implement and/or maintain additional I&E controls if the CWIS is located in a sensitive biological area.

- Facilities with CWIS located in an estuary or tidal river or ocean that do not exceed the intake withdrawal threshold, facilities with a CWIS located in a freshwater river or stream that exceed the intake withdrawal threshold for freshwater rivers or streams (greater than 5 percent of the source water mean annual flow), and facilities with CWIS located in one of the Great Lakes must implement and/or maintain both I&E controls.

- Facilities with a CWIS located in a freshwater river or stream that do not exceed the intake withdrawal threshold and all facilities with CWIS in a lake or reservoir, must implement and/or maintain impingement controls only. In addition, facilities with CWIS located in a lake or reservoir must not disrupt the natural thermal stratification or turnover pattern of the source waterbody unless such disruption is determined to be beneficial to fish and shellfish.

Facilities with recirculating cooling system based requirements would have the choice of complying with Track I or Track II requirements. If a facility chose to comply with Track II, then the facility would have to demonstrate that alternative technologies would reduce I&E to levels comparable to those that would be achieved with a closed-loop recirculating system

(90 percent reduction). If such a facility chose to supplement its alternative technologies with restoration measures, it would have to demonstrate the same or substantially similar level of protection.

EPA analyzed two different cases of the waterbody/capacity-based option: the first case assumes that all facilities with a recirculating cooling system based requirements would comply with Track I and install a wet cooling tower (Option 1); the second, more likely, case assumes that a percentage of the facilities with a recirculating cooling system based requirements would comply with Track II and conduct a comprehensive waterbody characterization study and install technologies other than wet cooling towers (Option 2). Under Option 1, 54 facilities are assumed to install a cooling tower; under Option 2, 33 facilities are assumed to install a cooling tower.

b. Impingement mortality and entrainment controls everywhere (Option 3a)

The impingement mortality and entrainment controls everywhere option would require the implementation of technologies that reduce impingement mortality and entrainment at all Phase II facilities without regard to waterbody type and with no site-specific compliance option available. EPA would specify a range of impingement mortality and entrainment reduction that is the same as the performance requirements under the proposed rule (i.e., Phase II facilities would be required to reduce impingement mortality by 80 to 95 percent for fish and shellfish, and to reduce entrainment by 60 to 90 percent for all life stages of fish and shellfish). However, unlike the proposed option, performance requirements under this alternative would apply to all Phase II facilities regardless of the category of waterbody used for cooling water withdrawals. Like the proposed option, the percent I&E reduction under this alternative would be relative to the calculation baseline. Thus, the baseline for assessing performance would be an existing facility with a shoreline intake with the capacity to support once-through cooling water systems and no impingement or entrainment controls. In addition, as under the proposed rule, a Phase II facility could demonstrate either that it currently meets the performance requirements or that it would upgrade its facility to meet these requirements.

EPA would set technology-based performance requirements under this alternative but would not mandate the use of any specific technology. Unlike the proposed option, this alternative would not allow for the development of BTA on a site-specific basis (except on a best professional judgment basis). This alternative would not base requirements on the percent of source water withdrawn or restrict disruption of the natural thermal stratification of lakes or reservoirs. However, it would impose entrainment performance requirements on Phase II facilities located on all waterbody types including freshwater rivers or streams, and lakes or reservoirs.

Finally, under this alternative, restoration could be used, but only as a supplement to the use of design and construction technologies or operational measures. This alternative would establish clear performance-based requirements that are simpler and easier to implement than those proposed and are based on the use of available technologies to reduce AEI.

c. Intake capacity commensurate with closed-cycle, recirculating cooling systems for all facilities (Option 4)

This option, referred to as the “all cooling towers option,” would require all Phase II facilities with a design intake flow of 50 MGD or more to reduce the total design intake flow to a level commensurate with that which can be attained by a closed-cycle recirculating cooling system. In addition, facilities in specified circumstances (e.g., located where additional protection is needed due to concerns regarding threatened, endangered, or protected species or habitat; or migratory, sport, or commercial species of concern) would have to select and implement design and construction technologies to minimize impingement mortality and entrainment. This option does not distinguish between facilities on the basis of the waterbody from which they withdraw cooling water. Rather, it would ensure that the same stringent controls are the nationally applicable minimum for all waterbody types.

d. Flow reduction commensurate with the level achieved by dry cooling systems based on waterbody type (Option 5)

Under this option, referred to as the “dry cooling option,” two types of facilities would be required to reduce their intake capacity to a zero or nearly zero intake flow, achievable with dry cooling systems: (1) facilities with CWIS located in a tidal river or estuary, if the intake flow is greater than one percent of the source water tidal excursion and (2) facilities with CWIS located in an ocean, if the intake flow is greater than 500 MGD. All other facilities have compliance requirements similar to the waterbody/capacity-based option.

e. Intake capacity commensurate with closed-cycle, recirculating cooling systems for all facilities located on an estuary or tidal river or ocean (Option 6)

Under this option, all facilities located on an estuary or tidal river or ocean must reduce intake flow commensurate with a level that can be achieved by a closed-cycle, recirculating system, regardless of proportional intake flow. Facilities with a CWIS located in one of the Great Lakes must implement and/or maintain both I&E controls. Facilities with a cooling water intake structure located in a freshwater river or stream that exceed the intake withdrawal threshold for freshwater rivers or streams (greater than 5 percent of the source water mean annual flow) must implement and/or maintain I&E controls. Facilities with a CWIS located in a freshwater river or stream that do not exceed the intake withdrawal threshold and all facilities with CWIS in a lake or reservoir, must implement and/or maintain impingement controls only. In addition, facilities with CWIS located in a lake or reservoir must not disrupt the natural thermal stratification or turnover pattern of the source waterbody unless such disruption is determined to be beneficial to fish and shellfish.

While this option was considered in the development of the proposed Phase II regulation, EPA did not estimate costs or economic impacts for this option. The remainder of the EBA will present benefits for this option, but will not discuss it in any of the chapters in *Part B: Costs and Economic Impacts*.

A1-5 Compliance Responses of the Proposed Rule and Alternative Options

Table A1-1 shows compliance response assumptions for the proposed rule and five alternative regulatory options based on each facility's current technologies installed, capacity utilization, waterbody type, annual intake flow, and design intake flow as a percent of source waterbody mean annual flow.

Table A1-1: Number of Facilities by Compliance Assumption and Regulatory Option (based on 539 sample facilities)

Facility Compliance Assumption	Waterbody/Capacity-Based Option (Allows two tracks)		Proposed Rule (Option 3)	Impingement Mortality and Entrainment Controls Everywhere (Option 3a)	All Cooling Towers (Option 4)	Dry Cooling (Option 5)	Waterbody Based (Option 6)
	Option 1	Option 2					
Cooling tower in baseline (no action)	*69*	*69*	*69*	*69*	*69*	*69*	*69*
Impingement Controls Only							
<15% capacity utilization	53	53	53	53	53	53	53
Freshwater Lakes	94	94	94	0	0	94	94
Freshwater Streams and Rivers [a]	94	94	94	0	0	94	94
Great Lakes	0	0	0	0	0	0	0
Estuaries, Tidal Rivers, and Oceans	0	0	0	0	0	0	0
Total Impingement Controls Only	*241*	*241*	*241*	*53*	*53*	*241*	*241*
I&E Controls							
Freshwater Lakes	0	0	0	94	0	0	0
Freshwater Streams and Rivers [a]	107	107	107	201	0	107	107
Great Lakes	13	13	13	13	0	13	13
Estuaries, Tidal Rivers, and Oceans [b]	58	78	109	109	0	58	0
Total I&E Controls	*178*	*198*	*229*	*417*	*0*	*178*	*120*
Flow Reduction Technology							
Freshwater Lakes	0	0	0	0	94	0	0
Freshwater Streams and Rivers	0	0	0	0	201	0	0
Great Lakes	0	0	0	0	13	0	0
Estuaries, Tidal Rivers, and Oceans [b]	51	31	0	0	109	51	109
Total Flow Reduction Technology [c]	*51*	*31*	*0*	*0*	*417*	*51*	*109*
Total	**539**	**539**	**539**	**539**	**539**	**539**	**539**

[a] Options 1, 2, 3, 5 and 6: A facility located on a freshwater river or stream with a design intake flow of ≤5% of the source water annual mean flow will be required to install impingement controls only, while a facility with a design intake flow of >5% of the source water annual mean flow will be required to install both I&E controls.

[b] Options 1, 2 and 5: A facility located on an estuary or tidal river with an intake flow ≤ 1% of the source water tidal excursion or on an ocean with an intake flow ≤500 MGD will be required to install I&E technologies. Option 1 assumes that all 51 facilities that do not meet that criteria will install flow reduction technologies commensurate with a closed-cycle recirculating system. Option 2 assumes that 31 facilities will install flow reduction commensurate with a closed-cycle recirculating system and the remaining 20 facilities will use track II (conduct a baseline characterization study) and install I&E controls. Option 5 assumes that all 51 facilities that do not meet that criteria will install flow reduction technologies commensurate with a dry cooling system.

[c] Options 1, 2, 4, 5 and 6: In addition to flow reduction technologies, facilities in specified circumstances (e.g., located where additional protection is needed due to concerns regarding threatened, endangered, or protected species or habitat; migratory, sport or commercial species of concern) would have to select and implement design and construction technologies to minimize impingement mortality and entrainment.

Source: U.S. EPA analysis, 2002.

A1-6 Organization of the EBA Report

The *Economic and Benefits Analysis for the Proposed Section 316(b) Phase II Existing Facilities Rule* (EBA) assesses the economic impacts and benefits of the proposed Phase II rule. The EBA consists of four parts. It is organized as follows:

PART A: BACKGROUND INFORMATION

- ***Chapter A1: Introduction and Overview*** presents the scope, key definitions, and a summary of the proposed rule and five alternative regulatory options.
- ***Chapter A2: The Need for Section 316(b) Regulation*** provides a brief discussion of the industry sectors and facilities affected by this regulation, discusses the environmental impacts from operating CWIS, and explains the need for this regulatory effort.
- ***Chapter A3: Profile of the Electric Power Industry*** presents a profile of the electric power market and the existing utility and nonutility steam electric power generating facilities analyzed for this regulatory effort

PART B: COSTS AND ECONOMIC IMPACTS

- ***Chapter B1: Summary of Compliance Costs*** summarizes the unit costs of compliance with the proposed rule and alternative regulatory options, presents EPA's assessment of compliance years, and presents the national cost of the proposed rule.
- ***Chapter B2: Cost Impact Analysis*** presents an assessment of the magnitude of compliance costs with the proposed Phase II rule, including a cost-to-revenue analysis at the facility and firm levels, a state-level analysis of compliance costs per household, and an analysis of compliance costs relative to electricity price projections at the North American Electric Reliability Council (NERC) level.
- ***Chapter B3: Electricity Market Model Analysis*** presents an analysis of the proposed rule using an integrated electricity market model. The chapter discusses potential energy effects of the proposed Phase II rule at the NERC region and national levels, and presents facility-level impacts.
- ***Chapter B4: Regulatory Flexibility Analysis*** presents EPA's estimates of small business impacts from the proposed Phase II rule.
- ***Chapter B5: UMRA Analysis*** outlines the requirements for analysis under the Unfunded Mandates Reform Act and presents the results of the analysis for this proposed rule.
- ***Chapter B6: Other Administrative Requirements*** presents several other analyses in support of the proposed Phase II rule. These analyses address the requirements of Executive Orders and Acts applicable to this rule.
- ***Chapter B7: Alternative Options - Costs and Economic Impacts*** describes the costs and economic impacts of four alternative regulatory options considered by EPA
- ***Chapter B8: Alternative Options - Electricity Market Model Analysis*** presents an analysis of two alternative regulatory options using an integrated electricity market model. The chapter discusses potential energy effects of the waterbody/capacity-based option (Option 1) and the all cooling towers option (Option 4) at the NERC region and national levels, and presents facility-level impacts.

PART C: NATIONAL BENEFITS

- ***Chapter C1: Introduction to the Case Studies*** provides an overview of why EPA chose a case study approach for analyzing benefits, how and why the case study sites were selected, and the design of the analyses.
- ***Chapter C2: Summary of Case Study Results*** summarizes the findings from each case study analysis and presents

EPA's estimate of I&E nation-wide based on extrapolation from case study results.

- ***Chapter C3: National Extrapolation of Baseline Economic Losses*** details the methods used to extrapolate the economic value of case study losses to obtain national loss estimates and presents EPA's best estimates of national baseline economic losses.

- ***Chapter C4: Benefits*** presents the expected national reductions in I&E under the proposed rule and five alternative regulatory options and applies these reductions to the national baseline losses reported in Chapter C3 to obtain an estimate of national benefits attributable to section 316(b) regulation.

PART D: NATIONAL BENEFIT-COST ANALYSIS

- ***Chapter D1: Comparison of National Costs and Benefits*** summarizes total private costs, develops social costs, and compares total social costs to total benefits at the national level. Results are presented for the proposed rule and five alternative regulatory options.

REFERENCES

U.S. Environmental Protection Agency (U.S. EPA). 2000. Section 316(b) Industry Survey. *Detailed Industry Questionnaire: Phase II Cooling Water Intake Structures* and *Industry Short Technical Questionnaire: Phase II Cooling Water Intake Structures*, January, 2000 (OMB Control Number 2040-0213). *Industry Screener Questionnaire: Phase I Cooling Water Intake Structures*, January, 1999 (OMB Control Number 2040-0203).

U.S. Environmental Protection Agency (U.S. EPA). 2002. *Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Rule*. EPA-821-R-02-003. February 2002.

Chapter A2: Need for the Regulation

Introduction

Section 316(b) of the Clean Water Act (CWA) directs EPA to assure that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact (AEI). Based on this statutory language, section 316(b) is already in effect and should be implemented with each NPDES permit issued to a directly discharging facility. However, no national standard for BTA that will minimize AEI from cooling water intake structures (CWIS) has been established to date. As a result, many CWIS have been constructed on sensitive aquatic systems with capacities and designs that cause damage to the waterbodies from which they withdraw water. In addition, the absence of regulations that establish standards for BTA has led to an inconsistent application of section 316(b). In fact, only 145 out of 550 facilities with flows greater than 50 million gallons per day (MGD) have indicated on EPA's 2000 Section 316(b) Industry Survey that they have ever performed a section 316(b) study (U.S. EPA, 2000).

Chapter Contents

This chapter provides a brief overview of the facilities subject to this rule and their use of cooling water, and presents the need for this regulation.

A2-1 Overview of Regulated Facilities

The Proposed Section 316(b) Phase II Existing Facilities Rule applies to existing power producing facilities with a design intake flow of 50 MGD or greater. The Phase II rule also covers substantial additions or modifications to operations undertaken at such facilities. The proposed Phase II rule does not cover (1) new steam electric power generating facilities, (2) new manufacturing facilities, (3) existing steam electric power generating facilities with a design intake flow of less than 50 MGD, and (4) existing manufacturing facilities.[1]

The remainder of this section describes the industry sectors subject to the Phase II rule and the existing utility and nonutility steam electric power generating facilities analyzed for this regulatory effort. *Chapter A3: Profile of the Electric Power Industry* and *Chapter B3: Electricity Market Model Analysis* of this Economic and Benefits Analysis (EBA) present more detailed information on the facilities subject to the Phase II rule and the market in which they operate.

A2-1.1 Phase II Sector Information

Past section 316(b) regulatory efforts and EPA's effluent guidelines program identified steam electric generators as the largest industrial users of cooling water. The condensers that support the steam turbines in these facilities require substantial amounts of cooling water. EPA estimates that steam electric utility power producers (SIC Codes 4911 and 4931) and steam electric nonutility power producers (SIC Major Group 49) account for approximately 92.5 percent of total cooling water

[1] New facilities were covered under the final section 316(b) New Facility Rule (Phase I), which EPA promulgated in November 2001. Existing steam electric power generating facilities with a design intake flow of less than 50 MGD and existing manufacturing facilities will be addressed by a separate rule.

intake in the United States (U.S. EPA, 2001). Beyond steam electric generators, other industrial facilities use cooling water in their production processes (e.g., to cool equipment, for heat quenching, etc.).

EPA's 2000 Section 316(b) Industry Survey collected cooling water information for 676 power producers and 396 other industrial facilities. These facilities withdraw 216 and 26.5 billion gallons per day (BGD) of cooling water, respectively. Of the power producers, 539 meet the "in-scope" requirements of this proposed rule. These 539 facilities represent 550 facilities in the industry.[2] Based on the survey, the 550 Phase II facilities account for approximately 216 BGD, or 96.3 percent of all estimated power producers. Industrial categories other than power producers are not covered by this proposed Phase II rule.

Table A2-1 summarizes cooling water use information of steam electric power generating facilities and major industrial categories.

Table A2-1: Estimated Cooling Water Intake by Sector - EPA Survey

Sector[a]	Estimated Number of Facilities	Total Cooling Water Intake Average Flow	Cooling Water Intake Average Flow Subject to Phase II Rule	
		Billion Gal./Yr.	Billion Gal./Yr.	Percent of Total Steam Electric and Industrial
Steam Electric Power Producers	708	81,753	78,703	82.4%
Steam Electric Utility Power Producers	*591*	*72,665*	*71,471*	*74.8%*
Steam Electric Nonutility Power Producers	*117*	*9,088*	*7,232*	*7.6%*
Major Industrial Categories[b]	773	13,752	0	0.0%
Total Steam Electric and Industrial	1,481	95,505	78,703	82.4%

[a] Estimates for each sector are based on facility categorization at the time of the survey; some utility facilities have since been sold to non-utilities.

[b] Major industrial categories (major SIC codes) surveyed with EPA questionnaires: Paper and Allied Products (SIC Major Group 26), (2) Chemicals and Allied Products (SIC Major Group 28), (3) Petroleum and Coal Products (SIC Major Group 29), and (4) Primary Metals Industries (SIC Major Group 33).

Source: U.S. EPA, 2000.

A2-1.2 Phase II Facility Information

The 550 steam electric power generating facilities subject to the proposed Phase II rule comprise a substantial portion of the U.S. electric power market. As shown in Table A2-2, the 550 facilities represent 13 percent of all facilities in the U.S. electric power market. In 2008, the Phase II facilities are projected to have a generating capacity of 416,000 MW (48 percent of total), generate 2.3 billion MWh of electricity (56 percent of total), and realize $75 billion in revenues (49 percent of total).

[2] EPA applied sample weights to the 539 facilities to account for non-sampled facilities and facilities that did not respond to the survey. For more information on EPA's 2000 Section 316(b) Industry Survey, please refer to the Information Collection Request (U.S. EPA, 2000).

Table A2-2: Summary Economic Data for Electricity Market and Phase II Facilities

Economic Measure	Industry Total[a]	Facilities Subject to Phase II Rule[b]	
		Phase II Total	% of Industry Total
Number of Facilities	4,091	550	13%
Electric Generating Capacity (MW)	875,000	416,000	48%
Net Generation (million MWh)	4,100	2,300	56%
Revenues (in billions, $2001)	$152	$75	49%

[a] Industry Totals are based on ICF Consulting's Integrated Planning Model (IPM®), section 316(b) base case, 2008. The IPM models 4,091 unique facilities. Industrial boilers are not modeled by the IPM. For a discussion of EPA's use of the IPM in support of this proposed rule, see *Chapter B3: Electricity Market Model Analysis*.

[b] The IPM models 540 of the 550 Phase II facilities. Eleven of the 540 facilities are closures in the section 316(b) base case run for 2008. The Phase II totals for capacity, generation, and revenues include the activities of the 529 in-scope facilities that are modeled by the IPM and are not closures in the base case.

Source: IPM analysis: model run for Section 316(b) base case, 2008.

Most of the analyses of economic impacts and energy effects presented in this Economic and Benefits Analysis present results by geographic region (i.e., North American Electric Reliability Council, or "NERC," region). Analyzing results by geographic region is of interest because regional concentrations of compliance costs could adversely impact electric power system reliability and prices, if a large percentage of overall capacity is affected. Some analyses are also presented by plant type. Analyzing results by plant type is of interest because a regulation that has disproportionate effects on particular types of facilities could lead to shifts in technology selection, if the effects are substantial enough.

Table A2-3 presents the distribution of facilities subject to the Phase II rule by NERC region and plant type. The table shows that the majority of facilities subject to the Phase II rule, 299, or 54.5 percent, are coal-fired steam-electric facilities. The other major plant types are oil- or gas-fired steam-electric facilities (169, or 30.8 percent) and nuclear facilities (57, or 10.4 percent). The remaining 4.4 percent are combined-cycle or other steam facilities. On a regional level, the East Central Area Reliability Council (ECAR) and the Southeastern Electric Reliability Council (SERC) account for the highest numbers of Phase II facilities with 100 (18.3 percent) and 95 (17.3 percent), respectively.

Table A2-3: Distribution of Phase II Facilities by NERC Region and Plant Type

NERC Region[a]	Coal	Combined Cycle	Nuclear	Oil/Gas	Other Steam	Total	Percent of Phase II
ASCC	1	0	0	0	0	**1**	**0.2%**
ECAR	91	0	6	3	0	**100**	**18.3%**
ERCOT[b]	9	1	2	39	0	**51**	**9.3%**
FRCC	7	5	1	17	0	**30**	**5.5%**
HI	0	0	0	3	0	**3**	**0.5%**
MAAC	17	2	7	15	2	**44**	**8.0%**
MAIN	41	0	8	2	0	**51**	**9.3%**
MAPP	34	0	4	6	0	**44**	**8.1%**
NPCC	17	4	9	28	5	**62**	**11.4%**
SERC	55	1	17	22	0	**95**	**17.3%**
SPP	19	0	1	12	0	**32**	**5.8%**
WSCC	7	3	2	21	1	**34**	**6.3%**
Total	**299**	**16**	**57**	**169**	**8**	**549**	
Percent of Phase II	**54.5%**	**2.9%**	**10.4%**	**30.8%**	**1.5%**		

[a] **Key to NERC regions:** ASCC – Alaska Systems Coordinating Council; ECAR – East Central Area Reliability Coordination Agreement; ERCOT – Electric Reliability Council of Texas; FRCC – Florida Reliability Coordinating Council; HI – Hawaii; MAAC – Mid-Atlantic Area Council; MAIN – Mid-America Interconnect Network; MAPP – Mid-Continent Area Power Pool; NPCC – Northeast Power Coordinating Council; SERC – Southeastern Electric Reliability Council; SPP – Southwest Power Pool; WSCC – Western Systems Coordinating Council.

[b] The plant type for one facility in ERCOT was not available. The total number of Phase II facilities presented in this table therefore is 549, not 550.

Source: U.S. DOE 1999a; U.S. DOE 1999b

A2-2 The Need for Section 316(b) Regulation

The withdrawal of cooling water removes trillions of aquatic organisms from waters of the U.S. 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 on components of the intake structure or entrained in the cooling water system itself. Impingement takes place when organisms are trapped on the outer part of an intake structure or against a screening device during periods of intake water withdrawal. Impingement is caused primarily by hydraulic forces in the intake stream. Impingement can result in (1) starvation and exhaustion; (2) asphyxiation when the fish are forced against a screen by velocity forces that prevent proper gill movement or when organisms are removed from the water for prolonged periods; (3) descaling and abrasion by screen wash spray and other forms of physical damage.

Entrainment occurs when organisms are drawn into the intake water flow entering and passing through a CWIS and into a cooling water system. Organisms that become entrained are those organisms that are small enough to pass through the intake screens, primarily eggs and larval stages of fish and shellfish. As entrained organisms pass through a plant's cooling water system, they are subject to mechanical, thermal, and or toxic stress. Sources of such stress include physical impacts in the pumps and condenser tubing, pressure changes caused by diversion of the cooling water into the plant or by the hydraulic

effects of the condensers, sheer stress, thermal shock in the condenser and discharge tunnel, and chemical toxemia induced by antifouling agents such as chlorine.

Rates of impingement and entrainment (I&E) depend on species characteristics, the environmental setting in which a facility is located, and the location, design, and capacity of the facility's CWIS. Species that spawn in nearshore areas, have planktonic eggs and larvae, and are small as adults experience the greatest impacts, since both new recruits and reproducing adults are affected (e.g., bay anchovy in estuaries and oceans). In general, higher I&E is observed in estuaries and near coastal waters because of the presence of spawning and nursery areas. By contrast the young of freshwater species are generally epibenthic and/or hatch from attached egg masses rather than existing as free-floating individuals, and therefore freshwater species may be less susceptible to entrainment.

The likelihood of I&E also depends on facility characteristics. If the quantity of water withdrawn is large relative to the flow of the source waterbody, a larger number of organisms will be affected. Intakes located in nearshore areas tend to have greater ecological impacts than intakes located offshore, since nearshore areas are usually more biologically productive and have higher concentrations of aquatic organisms (see the Pilgrim-Seabrook comparison in *Part G: New England Ocean* of the *Case Study Analysis for the Proposed Section 316(b) Phase II Existing Facilities Rule.* EPA estimates that CWIS used by the 550 facilities subject to the proposed rule impinge and entrain billions of age 1 equivalent fish annually (see Table C2-10 in *Chapter C2: Summary of Case Study Results* of this EBA for further detail).

In addition to direct losses of aquatic organisms from I&E, there are a number of indirect, ecosystem-level effects that may 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.

Several factors drive the need for this final section 316(b) rule. Each of these factors is discussed in the following sections.

A2-2.1 Low Levels of Protection at Phase II Facilities

Facilities in the power producing industry use a wide variety of cooling water intake technologies to maximize cooling system efficiency, minimize damage to their operating systems, and to reduce environmental impacts. The following subsections present data on technologies that have been identified as effective in protecting aquatic organisms from I&E. EPA used information from its 2000 Section 316(b) Industry Survey to characterize the 550 in-scope Phase II facilities with respect to these technologies. Based on this information, EPA believes that many facilities subject to this proposed rule are not using BTA to minimize AEI.

a. Closed-cycle cooling systems

Closed-cycle cooling systems (e.g., systems employing cooling towers) are the most effective means of protecting organisms from I&E. Cooling towers reduce the number of organisms that come into contact with a CWIS because of the significant reduction in the volume of intake water needed by a closed-cycle facilities. Reduced water intake results in a significant reduction in damaged and killed organisms. Of the 550 in-scope Phase II facilities, 73 (13 percent) reported the use of closed-cycle cooling systems.

Table A2-4: Estimated Number of Facilities by CWS Configuration and CWIS Technology (Design Flow >= 50 MGD)

CWIS Technology	CWS Configuration							
	Once Through		Recirculating		Combination		None/unknown	
	#	%	#	%	#	%	#	%
Intake screening technologies	26	6.3%	0	0.0%	5	10.0%	0	0.0%
Passive intake systems	42	10.1%	13	17.8%	9	18.0%	1	9.1%
Fish diversion or avoidance systems	17	4.1%	2	2.7%	2	4.0%	0	0.0%
Fish handling or return technologies	53	12.7%	3	4.1%	7	14.0%	2	18.2%
Other/none/unknown	213	51.2%	46	63.0%	20	40.0%	7	63.6%
Combination of technologies	65	15.6%	9	12.3%	7	14.0%	1	9.1%
Total	**416**	**100.0%**	**73**	**100.0%**	**50**	**100.0%**	**11**	**100.0%**

Source: U.S. EPA, 2000.

b. Other CWIS technologies

Discussions with NPDES permitting authorities and utility officials identified fine mesh screens as an effective technology for minimizing entrainment. They can, however, increase impingement. Data from the questionnaires indicate that of the 550 in-scope Phase II facilities, seven (one percent) employed fine mesh screens on at least one CWIS. These seven plants represented less than one percent of the cooling water withdrawn from surface waters by plants reporting data. These findings indicate that, in general, BTA is not being used and further regulation is required.

Table A2-5: Estimated Number of Facilities by CWIS Technology (Design Flow >= 50 MGD)

CWIS Technology	Number of Facilities	Percent of Total
Intake screening technologies	31	5.6%
Passive intake systems	65	11.8%
Fish diversion or avoidance systems	21	3.8%
Fish handling or return technologies	65	11.8%
Other/none/unknown technology	286	52.0%
Combination of technologies	82	14.9%
Total	**550**	**100.0%**

Source: U.S. EPA, 2000.

c. Cooling system location

Another effective approach for minimizing AEI associated with CWIS is to locate the intake structures in areas with low abundance of aquatic life and design the structures so that they do not provide attractive habitat for aquatic communities. However, this approach is of little utility for existing facilities where options for relocating intake structures are infeasible.

Table A2-6 shows the estimated number of facilities by the source of water from which cooling water is withdrawn. The table indicates that 135 steam electric power generation facilities are located on estuaries, tidal rivers, or oceans that are considered to be areas of high productivity and abundance. In addition, estuaries are often nursery areas for many species. The flow to these facilities totaled 32 percent of the total cooling water being withdrawn by all in-scope Phase II facilities. However, the remaining 415 facilities (68 percent of flow) were reported as being located on fresh waterbodies (including Great Lakes).

Table A2-6: Estimated Number of Facilities by Source of Surface Water (Design Flow >= 50 MGD)

Source of Surface Water	Number of Facilities	Percent of Total
Estuary/Tidal river	112	20.4%
Freshwater stream/River	263	47.8%
Great Lake	16	2.9%
Lake/Reservoir	135	24.6%
Ocean	23	4.3%
Total[a]	**550**	**100.0%**

[a] Individual numbers may not add up due to independent rounding.

Source: U.S. EPA, 2000.

A2-2.2 Reducing Adverse Environmental Impacts

Adverse environmental impacts occur when facilities impinge aquatic organisms on the screens of their CWIS, entrain them within their cooling system, or otherwise negatively affect habitats that support aquatic species. Exposure of aquatic organisms to I&E depends on the location, design, construction, capacity, and operation of a facility's CWIS (U.S. EPA, 1976; SAIC, 1994; SAIC, 1996). The regulatory goals of section 316(b) include the following:

- ensure that the location, design, construction, and capacity of a facility's CWIS reflect best technology available for minimizing adverse environmental impact;
- protect individuals, populations, and communities of aquatic organisms from harm (reduced viability or increased mortality) due to the physical and chemical stresses of I&E; and
- protect aquatic organisms and habitat that are indirectly affected by CWIS because of trophic interactions with species that are impinged or entrained.

Impingement occurs when fish are trapped against intake screens by the velocity of the intake flow. Organisms may die or be injured as a result of:

- starvation and exhaustion,
- asphyxiation when velocity forces prevent proper gill movement,
- abrasion by screen wash spray,
- asphyxiation due to removal from water for prolonged periods, and
- removal from the system by means other than returning them to their natural environment.

Small organisms are entrained when they pass through a plant's condenser cooling system. Injury and death can result from the following:

- physical impacts from pump and condenser tubing,
- pressure changes caused by diversion of cooling water,
- thermal shock experienced in condenser and discharge tunnels, and

- chemical toxemia induced by the addition of anti-fouling agents such as chlorine.

Mortality of entrained organisms is usually extremely high.

Review of the available literature and section 316(b) demonstration studies has identified numerous documented cases of impacts associated with I&E and the effects of I&E on individual organisms and on populations of aquatic organisms. For example, specific losses attributed to individual steam electric generating plants include annual losses of 3 to 4 billion larvae, equivalent to 23 million adult fish and shellfish,[3] 23 tons of fish and shellfish of recreational, commercial, or forage value lost each year,[4] and 1 million fish lost during a three-week study period.[5] The yearly loss of billions of individuals is not the only problem. Often, there are impacts to populations as well. For example, studies of Hudson River fish populations predicted reductions of up to 20 percent for striped bass, 25 percent for bay anchovy, and 43 percent for Atlantic tom cod, even without assuming 100 percent mortality of entrained organisms.[6] Estimates of lost midwater fish species due to direct entrainment by CWIS at the San Onofre Nuclear Generating Station (SONGS) are between 16.5 to 45 tons per year.[7] This loss represents a 41 percent mortality rate for fish (primarily northern anchovy, queenfish, and white croaker) entrained by intake water at SONGS. In a normal year, approximately 350,000 juvenile white croaker are estimated to be killed through entrainment at SONGS. This number represents 33,000 adult individuals or 3.5 tons of adult fish. Changes in densities of fish populations within the vicinity of the plant, relative to control populations, were observed in species of queen fish and white croaker. The density of queenfish and white croaker within three kilometers of SONGS decreased by 34 to 63 percent in shallow water samples and 50 to 70 percent in deep water samples.

The main purpose of this regulation is to minimize losses such as those described above. See *Part C: National Benefits* and *Part D: Benefit-Cost Analysis* of this EBA for information on the ability of the different options to reduce impingement and entrainment. See also the *Case Study Analysis for the Proposed Section 316(b) Phase II Existing Facilities Rule* for detailed information on baseline losses at case study facilities.

A2-2.3 Addressing Market Imperfections

The conceptual basis of environmental legislation in general, and the Clean Water Act and the section 316(b) regulation in particular, is the need to correct imperfections in the markets that arise from uncompensated environmental externalities. Facilities withdraw cooling water from a water of the U.S. to support electricity generation, steam generation, manufacturing, and other business activities, and, in the process impinge and entrain organisms without accounting for the consequences of these actions on the ecosystem or other parties who do not directly participate in the business transactions. The actions of these section 316(b) facilities impose environmental harm or costs on the environment and on other parties (sometimes referred to as *third parties*). These costs, however, are not recognized by the responsible entities in the conventional market-based accounting framework. Because the responsible entities do not account for these costs to the ecosystem and society, they are *external* to the market framework and the consequent production and pricing decisions of the responsible entities. In addition, because no party is compensated for the adverse consequences of I&E, the externality is *uncompensated*.

Business decisions will yield a less than optimal allocation of economic resources to production activities, and, as a result, a less than optimal mix and quantity of goods and services, when external costs are not accounted for in the production and pricing decisions of the section 316(b) industries. In particular, the quantity of AEI caused by the business activities of the responsible business entities will exceed optimal levels and society will not maximize total possible welfare. Adverse distributional effects may be an additional effect of the uncompensated environmental externalities. If the distribution of I&E and ensuing AEI is not random among the U.S. population but instead is concentrated among certain population subgroups

[3] Brunswick Nuclear Steam Electric Generating Plant (U.S. EPA, Region IV, 1979).

[4] Crystal River Power Plant (U.S. EPA, Region IV, 1986).

[5] D.C. Cook Nuclear Power Plant (Thurber, 1985).

[6] Bowline Point, Indian Point 2 & 3, and Roseton Steam Electric Generating Stations (ConEd, 2000).

[7] San Onofre Nuclear Generating station (SAIC, 1993)

based on socio-economic or other demographic characteristics, then the uncompensated environmental externalities may produce undesirable transfers of economic welfare among subgroups of the population.

The goal of environmental legislation and subsequent implementing actions, such as the section 316(b) regulation that is the subject of this analysis, is to correct environmental externalities by requiring the responsible parties to reduce their actions causing environmental damage. Congress, in enacting the authorizing legislation, and EPA, in promulgating the implementing regulations, act on behalf of society to minimize environmental impacts (i.e., achieve a lower level of I&E and associated environmental harm). These actions result in a supply of goods and services that more nearly approximates the mix and level of goods and services that would occur if the industries impinging and entraining organisms fully accounted for the costs of their AEI-generating activities.

Requiring facilities to minimize their environmental impacts by reducing levels of I&E (i.e., reducing environmental harm) is one approach to addressing the problem of environmental externalities. This approach internalizes the external costs by turning the societal cost of environmental harm into a direct business cost – the cost of achieving compliance with the regulation – for the impinging and entraining entities. A facility causing AEI will either incur the costs of minimizing its environmental impacts, or will determine that compliance is not in its best financial interest and will cease the AEI-generating activities.

It is theoretically possible to correct the market imperfection by means other than direct regulation. Negotiation and/or litigation, for example, could achieve an optimal allocation of economic resources and mix of production activities within the economy. However, the transaction costs of assembling the affected parties and involving them in the negotiation/litigation process as well as the public goods character of the improvement sought by negotiation or litigation will frequently render this approach to addressing the market imperfection impractical. Although the environmental impacts associated with CWIS have been documented since the first attempt at section 316(b) regulation in the late 1970s, implementation of section 316(b) to date has failed to address the market imperfections associated with CWIS effectively.

A2-2.4 Reducing Differences Between the States

NPDES permitting authorities have implemented the requirements of section 316(b) in widely varying ways. The language used in the statutes or regulations vary from state to state almost as much as the interpretation. Most states do not address section 316(b) at all.

Table A2-7. below illustrates a variety of ways in which states identify the section 316(b) requirements.

Table.A2-7: Selected NPDES State Statutory/Regulatory Provisions Addressing Impacts from Cooling Water Intake Structures

NPDES State	Citation	Summary of Requirements
Connecticut	RCSA § 22a, 430-4	Provides for coordination with other Federal/State agencies with jurisdiction over fish, wildlife, or public health, which may recommend conditions necessary to avoid substantial impairment of fish, shellfish, or wildlife resources
New Jersey	NJAC § 7:14A-11.6	Criteria applicable to intake structure shall be as set forth in 40 *CFR* Part 125, when EPA adopts these criteria
New York	6 NYCRR § 704.5	The location, design, construction, and capacity of intake structures in connection with point source thermal discharges shall reflect BTA for minimizing environmental impact
Maryland	MRC § 26.08.03	Detailed regulatory provisions addressing BTA determinations
Illinois	35 Ill. Admin. Code 306.201 (1998)	Requirement that new intake structures on waters designated for general use shall be so designed as to minimize harm to fish and other aquatic organisms
Iowa	567 IAC 62.4(455B)	Incorporates 40 CFR part 401, with cooling water intake structure provisions designated "reserved"
California	Cal. Wat. Code § 13142.5(b)	Requirements that new or expanded coastal power plants or other industrial installations using seawater for cooling shall use best available site, design technology, and mitigation measures feasible to minimize intake and mortality of marine life

Source: SAIC, 1994b.

Additionally, in discussions with state and EPA regional contacts, EPA has found that states differ in the manner in which they implement their section 316(b) authority. Some states and regions review section 316(b) requirements each time an NPDES permit is reissued. These permitting authorities may reevaluate the potential for impacts and/or the environment that influences the potential for impacts at the facility. Other permitting authorities made initial determinations for facilities in the 1970s but have not revisited the determinations since.

Based on the above findings, EPA believes that approaches to implementing section 316(b) vary greatly. It is evident that some authorities have regulations and other program mechanisms in place to ensure continued implementation of section 316(b) and evaluation of potential impacts from CWIS, while others do not. Furthermore, there appears to be no mechanism to ensure consistency across all states. Section 316(b) determinations are currently made on a case-by-case basis, based on permit writers' best professional judgment. Through discussions with some state permitting officials (e.g., in California, Georgia, and New Jersey), EPA was asked to establish national standards in order to help ease the case-by-case burden on permit writers and to promote national uniformity with respect to implementation of section 316(b).

When environmental policies are implemented differently by two or more states that share access to the same waterbody, a conflict may occur between the states because environmental losses caused in one state may affect the biology, environmental conditions, and benefits of another state. Differences of this type are most likely to occur when the regulations governing the operation of CWIS are established at the state level or are implemented in fundamentally different ways by the states (i.e.,

more and less stringent due to policy or failure to implement). When this happens, the state with less stringent requirements imposes "external costs" or damages on the other state.

A good example of a conflict between states is in Mount Hope Bay, an interstate water straddling the Massachusetts/Rhode Island state line. Brayton Point Station in Somerset, Massachusetts is the largest fossil fuel-burning steam-electric generating facility in New England. The facility may have caused or contributed to a documented collapse in fish populations in Mount Hope Bay affecting Rhode Island as well as Massachusetts.

The plant uses a once-through-cooling water system and is allowed by its current NPDES permit to withdraw up to 1.452 billion gallons a day (BGD) of water from Mount Hope Bay for cooling and then to discharge the heated water back to the Bay at temperatures up to 22^0F above ambient water conditions. The current NPDES permit "expired" in June, 1998, but remains in effect while EPA develops a new permit. EPA co-issues this permit with the Massachusetts DEP. EPA must also coordinate closely with Rhode Island because its waters are also affected by the plant. The permit must ensure that both Massachusetts and Rhode Island water quality standards are satisfied unless a variance authorizing excursions from those standards is granted. Similarly, both states' Coastal Zone Management Programs must be satisfied, along with the federal Essential Fish Habitat program and other federal requirements.

There has been a significant amount of controversy about the plant because of the documented collapse of fish populations in Mount Hope Bay and the debate over the power plant's role in causing or contributing to the fishery decline. On October 9, 1996, Rhode Island Department of Environmental Management issued a report which documented an alarming, sharp decline in abundance of finfish populations in Mount Hope Bay that appeared to occur about seventeen years ago with no subsequent recovery in evidence. Additional review of the data has suggested that the fishery decline actually began, albeit at a gentler pace, before the sharp decline evidenced around 1985. Adverse effects of plant cooling system operations on aquatic organisms can be divided into the following major categories: (1) cooling water intake *entrainment* of fish eggs and larvae and other small organisms into the plant's cooling system; (2) cooling water intake *impingement* of larger organisms on the intake screening systems; and (3) discharge-related effects from the impacts of the thermal effluent on the aquatic community and its habitat. Entrainment and thermal discharge appear to be especially significant issues for this plant, with impingement appearing to be a relatively less major problem.

In response to the developing controversy, federal and state regulatory agencies and former plant owner NEPCO entered into a Memorandum of Agreement (MOA) in April, 1997, regarding plant operations. The MOA places annual and seasonal caps on the level of heat discharged and the amount of cooling water withdrawn from the Bay. In the MOA the Company agreed to limit its operations to levels below that authorized by the (still) current NPDES permit and the agencies agreed not to push for an immediate modification of the permit. (NEPCO had threatened to appeal any immediate permit modification anyway.) The intake volume and thermal discharge caps in the MOA represented a compromise between the levels initially sought by the regulatory agencies and the levels the company claimed were justified. The MOA also indicated that a number of types of research should be pursued to help with development of a new NPDES permit. When PG&E bought Brayton Point Station it assumed responsibility for complying with the MOA (the MOA required that agreement to comply with the MOA be made a condition of any sale of the plant). Since the 1997 MOA, the permittee and the regulatory agencies have been engaged in extensive monitoring, modeling and study to determine the conditions for a new NPDES permit.

On October 2, 2001, PG&E publicly announced a proposed $250,000,000 environmental improvement plan for the facility including new air pollution controls, ash recycling facilities, and a new cooling water system using mechanical draft wet cooling tower that PG&E refers to as the Enhanced Multi-Mode System. The Company intends this plan to address requirements under the new State air quality regulations, a State Administrative Consent Order addressing ash management practices, and the new NPDES permit. PG&E states that this new system will reduce heat loadings into Mount Hope Bay, and reduce cooling water withdrawals from Mount Hope Bay, to pre-1984 levels. The year 1984 is significant because it was the year that Brayton Point was permitted to switch Unit 4 from a previously closed-cycle cooling system to a once-through cooling system, and some data suggests that the steep decline in fish populations was coincidental with this modification. (As noted above, there is also data suggesting that the decline had started earlier but accelerated after Unit 4 began once-through cooling operations.)

EPA is working closely with Massachusetts and Rhode Island on the permit, and has also been coordinating with the National Marine Fisheries Service. The permit will be jointly issued with the state in Massachusetts which does not have NPDES delegation. EPA is also in close communication with the company regarding the issues, and the company has submitted a substantial amount of information supporting its view of what limits should be in the new permit. EPA has also received significant communications from interested environmental groups. In addition, there has been congressional interest in both

Massachusetts and Rhode Island as well as statements of concern by the Governor of Rhode Island. Public interest in the permit development is high. Over the past year serious concerns have been raised by groups including Save the Bay, Conservation Law Foundation, the Rhode Island Salt Water Anglers, and the New England Fishery Management Council. Also, the Rhode Island Attorney General has also been actively engaged in tracking the matter and has publicly threatened to sue the company over damage to Rhode Island's natural resources. Finally, the permit issues have received substantial attention in local major media outlets, including a recent front page story in the Boston Globe.

Options considered by EPA differ considerably in their ability to reduce implementation differences between two or more states that share access to the same waterbody. The greater the level of benefits associated with a regulation, the lower the level of I&E losses that can occur in one state and affect the biology, environmental conditions, and benefits of another state. Thus the greater the benefits of a regulation, the fewer the "external costs" or damages that can be imposed by one state on other states.

A2-2.5 Reducing Transaction Costs

Transaction costs associated with the implementation of a regulation include: (1) determining the desired level of environmental quality and (2) determining how to achieve it.

Transaction costs associated with determining the desired level of environmental quality have to do with the supply and demand for environmental quality.

The presence of uncertainties increases transaction costs. Some uncertainties relate to the supply of environmental quality (e.g., the actual impact of various control technologies in terms of the effectiveness of I&E reductions); others relate to the demand for environmental quality (e.g., the value of reduced I&E in terms of individual and population impacts). Reducing uncertainties would reduce transaction costs. Standardizing the protocol for monitoring and reporting I&E impacts reduces the uncertainty about how to measure the impact of controls, and provides for a uniform "language" for communicating these impacts. A federal regulation that establishes methods for mitigating the impact of regulatory uncertainty and information uncertainty produces a benefit in the form of reduced (transaction) costs.

There is another set of uncertainties that is independent of the desired level of environmental quality. These uncertainties fall into the broad categories of "regulatory uncertainty" and "information uncertainty." The costs related to these uncertainties lead to "transaction costs," which cause inefficiencies in decision-making related to achieving a given level of environmental quality. *Regulatory uncertainty* refers to the uncertainty that facilities face when making business decisions in response to regulatory requirements when those requirements are uncertain. For example, facilities are making business decisions today based on their best guess about what future regulation will look like. The cost of this uncertainty comes in the form of delayed business decisions and poor business decisions based on incorrect guesses about the future regulation. *Information uncertainty* refers to the uncertainty related to the measurement and communication of the impact of controls on actual I&E, as well as the impact of I&E on populations. The consequence of information uncertainty is poor decision-making by stakeholders (suppliers and demanders of environmental quality) and a reduction in the cost-effectiveness of meeting a desired level of environmental quality.

Transaction costs are incurred at several levels, including the states and Tribes authorized to implement the NPDES program; the federal government; and facilities subject to section 316(b) regulation.

Section 316(b) requirements are implemented through NPDES permits. States and Tribes authorized to implement the NPDES program do so through the issuance of permits to power producing facilities. Forty-four states and the Virgin Islands are currently authorized pursuant to section 402(b) of the CWA to implement the NPDES program. In states not authorized to implement the NPDES program, EPA issues NPDES permits. Under the CWA, states are not required to become authorized to administer the NPDES program. Rather, such authorization is available to states if they operate their programs in a manner consistent with section 402(b) and applicable regulations. Generally, these provisions require that state NPDES programs include requirements that are as stringent as federal program requirements. States retain the ability to implement requirements that are broader in scope or more stringent than federal requirements (See section 510 of the CWA).

Each state's, Tribe's, or region's burden associated with permitting activities depends on their personnel's background, resources, and the number of regulated facilities under their authority. Developing a permit requires technical and clerical

staff to gather, prepare, and review various documents and supporting materials, verify data sources, plan responses, determine specific permit requirements, write the actual permit, and confer with facilities and the interested public.

Where states and Tribal governments do not have NPDES permitting authority, the federal government implements section 316(b) regulations through its regional offices. The section 316(b) regulation is also necessary to reduce the burden on the regions.

Uncertainty about what constitutes AEI, and the BTA that would minimize AEI, also increases transaction costs to facilities. Without well-defined section 316(b) requirements, facilities have an incentive to delay or altogether avoid implementing I&E technologies by trying to show that their CWIS do not have impacts at certain levels of biological organization, e.g., population or community levels. Some facilities thus spend large amounts of time and money on studies and analyses without ever implementing technologies that would reduce I&E. Better definition of section 316(b) requirements could lead to a better use of these resources by investing them in I&E reduction rather than studies and analyses.

The options considered by EPA differ considerably in their ability to reduce transactions costs. The greater the site specific nature of the regulation the greater the transaction costs associated with the regulation. Options that are simpler, even though they may involve higher technology and operation and maintenance costs, are likely to have much lower transaction costs.

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Chapter A3: Profile of the Electric Power Industry

Introduction

This profile compiles and analyzes economic and financial data for the electric power generating industry. It provides information on the structure and overall performance of the industry and explains important trends that may influence the nature and magnitude of economic impacts from the Proposed Section 316(b) Phase II Existing Facilities Rule.

The electric power industry is one of the most extensively studied industries. The Energy Information Administration (EIA), among others, publishes a multitude of reports, documents, and studies on an annual basis. This profile is not intended to duplicate those efforts. Rather, this profile compiles, summarizes, and presents those industry data that are important in the context of the proposed Phase II rule. For more information on general concepts, trends, and developments in the electric power industry, the last section of this profile, "References," presents a select list of other publications on the industry.

Chapter Contents

The remainder of this profile is organized as follows:

- Section A3-1 provides a brief overview of the industry, including descriptions of major industry sectors, types of generating facilities, and the entities that own generating facilities.
- Section A3-2 provides data on industry production and capacity.
- Section A3-3 focuses on the in-scope section 316(b) facilities. This section provides information on the geographical, physical, and financial characteristics of the in-scope phase II facilities.
- Section A3-4 provides a brief discussion of factors affecting the future of the electric power industry, including the status of restructuring, and summarizes forecasts of market conditions through the year 2020.

A3-1 Industry Overview

This section provides a brief overview of the industry, including descriptions of major industry sectors, types of generating facilities, and the entities that own generating facilities.

A3-1.1 Industry Sectors

The electricity business is made up of three major functional service components or sectors: *generation*, *transmission*, and *distribution*. These terms are defined as follows (Beamon, 1998; Joskow, 1997):[1]

- The ***generation*** sector includes the power plants that produce, or "generate," electricity.[2] Electric energy is produced using a specific generating technology, e.g., internal combustion engines and turbines. Turbines can be driven by wind, moving water (hydroelectric), or steam from fossil fuel-fired boilers or nuclear reactions. Other methods of power generation include geothermal or photovoltaic (solar) technologies.

- The ***transmission*** sector can be thought of as the interstate highway system of the business – the large, high-voltage power lines that deliver electricity from power plants to local areas. Electricity transmission involves the "transportation" of electricity from power plants to distribution centers using a complex system. Transmission requires: interconnecting and integrating a number of generating facilities into a stable, synchronized, alternating current (AC) network; scheduling and dispatching all connected plants to balance the demand and supply of electricity in real time; and managing the system for equipment failures, network constraints, and interaction with other transmission networks.

- The ***distribution*** sector can be thought of as the local delivery system – the relatively low-voltage power lines that bring power to homes and businesses. Electricity distribution relies on a system of wires and transformers along streets and underground to provide electricity to residential, commercial, and industrial consumers. The distribution system involves both the provision of the hardware (e.g., lines, poles, transformers) and a set of retailing functions, such as metering, billing, and various demand management services.

Of the three industry sectors, only electricity generation uses cooling water and is subject to section 316(b). The remainder of this profile will focus on the generation sector of the industry.

A3-1.2 Prime Movers

Electric power plants use a variety of ***prime movers*** to generate electricity. The type of prime mover used at a given plant is determined based on the type of load the plant is designed to serve, the availability of fuels, and energy requirements. Most prime movers use fossil fuels (coal, petroleum, and natural gas) as an energy source and employ some type of turbine to produce electricity. The six most common prime movers are (U.S. DOE, 2000a):

- ***Steam Turbine:*** Steam turbine, or "steam electric" units require a fuel source to boil water and produce steam that drives the turbine. Either the burning of fossil fuels or a nuclear reaction can be used to produce the heat and steam necessary to generate electricity. These units are generally ***baseload*** units that are run continuously to serve the minimum load required by the system. Steam electric units generate the majority of electricity produced at power plants in the U.S.

- ***Gas Combustion Turbine:*** Gas turbine units burn a combination of natural gas and distillate oil in a high pressure chamber to produce hot gases that are passed directly through the turbine. Units with this prime mover are generally less than 100 megawatts in size, less efficient than steam turbines, and used for ***peakload*** operation serving the highest daily, weekly, or seasonal loads. Gas turbine units have quick startup times and can be installed at a variety of site locations, making them ideal for peak, emergency, and reserve-power requirements.

- ***Combined-Cycle Turbine:*** Combined-cycle units utilize both steam and gas turbine prime mover technologies to increase the efficiency of the gas turbine system. After combusting natural gas in gas turbine units, the hot gases from the turbines are transported to a waste-heat recovery steam boiler where water is heated to produce steam for a second steam turbine. The steam may be produced solely by recovery of gas turbine exhaust or with additional fuel input to the steam boiler. Combined-cycle generating units are generally used for ***intermediate loads***.

[1] Terms highlighted in bold and italic font are defined in the glossary at the end of this chapter.

[2] The terms "plant" and "facility" are used interchangeably throughout this profile.

- ***Internal Combustion Engines:*** Internal combustion engines contain one or more cylinders in which fuel is combusted to drive a generator. These units are generally about 5 megawatts in size, can be installed on short notice, and can begin producing electricity almost instantaneously. Like gas turbines, internal combustion units are generally used only for peak loads.

- ***Water Turbine:*** Units with water turbines, or "hydroelectric units," use either falling water or the force of a natural river current to spin turbines and produce electricity. These units are used for all types of loads.

- ***Other Prime Movers:*** Other methods of power generation include geothermal, solar, wind, and biomass prime movers. The contribution of these prime movers is small relative to total power production in the U.S., but the role of these prime movers may expand in the future because recent legislation includes incentives for their use.

Table A3-1 provides data on the number of existing utility and nonutility power plants by prime mover. This table includes all plants that have at least one non-retired unit and that submitted Forms EIA-860A (Annual Electric Generator Report - Utilities) or EIA-860B (Annual Electric Generator Report - Nonutilities) in 1999.[3] For the purpose of this analysis, plants were classified as "steam turbine" or "combined-cycle" if they have at least one generating unit of that type. Plants that do not have any steam electric units, were classified under the prime mover type that accounts for the largest share of the plant's total electricity generation.

Table A3-1: Number of Existing Utility and Nonutility Plants by Prime Mover, 1999

Prime Mover	Utility[a]	Nonutility[a]
	Number of Plants	Number of Plants
Steam Turbine	803	821
Combined-Cycle	59	201
Gas Turbine	335	372
Internal Combustion	642	245
Hydroelectric	1,237	476
Other	49	90
Total	**3,125**	**2,205**

[a] See definition of utility and nonutility in Section A3-1.3.

Source: U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c.

Only prime movers with a steam electric generating cycle use substantial amounts of cooling water. These generators include steam turbines and combined-cycle technologies. As a result, the analysis in support of the proposed Phase II rule focuses on generating plants with a steam electric prime mover. This profile will, therefore, differentiate between steam electric and other prime movers.

A3-1.3 Ownership

The U.S. electric power industry consists of two broad categories of firms that own and operate electric generating plants: utilities and nonutilities. Generally, they can be defined as follows (U.S. DOE, 2000a):

- ***Utility:*** A regulated entity providing electric power, traditionally vertically integrated. Utilities may or may not generate electricity. "Transmission utility" refers to the regulated owner/operator of the transmission system only. "Distribution utility" refers to the regulated owner/operator of the distribution system serving retail customers.

[3] At the time of publication of this document, 1999 was the most recent year for which complete EIA data were available for existing utility and nonutility plants. As of March 2002 EIA 860B data were not available for year 2000. As such, this profile is based on 1999 data.

- ***Nonutility:*** Entities that generate power for their own use and/or for sale to utilities and others. Nonutility power producers include cogenerators, small power producers, and independent power producers. Nonutilities do not have a designated franchised service area and do not transmit or distribute electricity.

Utilities can be further divided into three major ownership categories: investor-owned utilities, publicly-owned utilities, and rural electric cooperatives. Each category is discussed below.

a. Investor-owned utilities

Investor-owned utilities (IOUs) are for-profit businesses that can take two basic organizational forms: the individual corporation and the holding company. An individual corporation is a single utility company with its own investors; a holding company is a business entity that owns one or more utility companies and may have other diversified holdings as well. Like all businesses, the objective of an IOU is to produce a return for its investors. IOUs are entities with designated franchise areas. They are required to charge reasonable and comparable prices to similar classifications of consumers and give consumers access to services under similar conditions. Most IOUs engage in all three activities: generation, transmission, and distribution. In 1999, IOUs operated 1,662 facilities, which accounted for approximately 58 percent of all U.S. electric generation capacity (U.S. DOE, 1999a; U.S. DOE, 1999c; U.S. DOE, 1998c).

b. Publicly-owned utilities

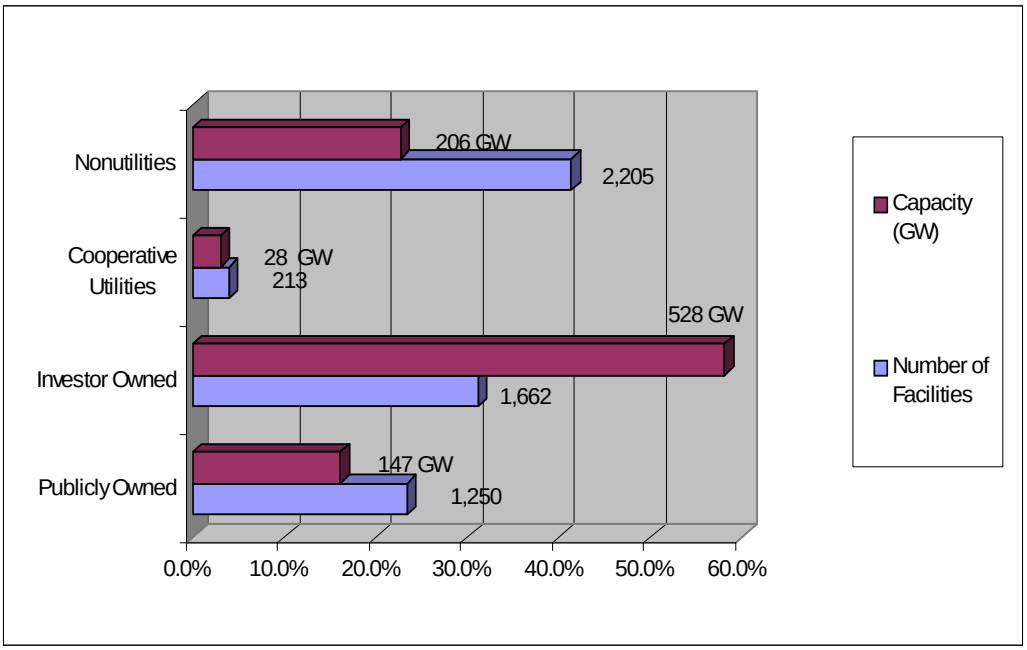
Publicly-owned electric utilities can be municipalities, public power districts, state authorities, irrigation projects, and other state agencies established to serve their local municipalities or nearby communities. Excess funds or “profits” from the operation of these utilities are put toward community programs and local government budgets, increasing facility efficiency and capacity, and reducing rates. This profile also includes federally-owned facilities in this category. Most municipal utilities are nongenerators engaging solely in the purchase of wholesale electricity for resale and distribution. The larger municipal utilities, as well as state and federal utilities, usually generate, transmit, and distribute electricity. In general, publicly-owned utilities have access to tax-free financing and do not pay certain taxes or dividends, giving them some cost advantages over IOUs. In 1999, publicly-owned utilities operated 1,250 facilities and accounted for approximately 16 percent of all U.S. electric generation capacity (U.S. DOE, 1999a; U.S. DOE, 1999c; U.S. DOE, 1998c).

c. Rural electric cooperatives

Cooperative electric utilities (“coops”) are member-owned entities created to provide electricity to those members. These utilities, established under the Rural Electrification Act of 1936, provide electricity to small rural and farming communities (usually fewer than 1,500 consumers). The National Rural Utilities Cooperative Finance Corporation, the Federal Financing Bank, and the Bank of Cooperatives are important sources of financing for these utilities. Cooperatives operate in 34 states and are incorporated under state laws. In 1999, rural electric cooperatives operated 213 generating facilities, and accounted for approximately 3 percent of all U.S. electric generation capacity. (U.S. DOE, 1999a; U.S. DOE, 1999c; U.S. DOE, 1998c).

Figure A3-1 presents the number of generating facilities and their capacity in 1999, by type of ownership.[4] The horizontal axis also presents the percentage of the U.S. total that each type represents. This figure is based on data for all plants that have at least one non-retired unit and that submitted Forms EIA-860A or EIA-860B in 1999. The graphic shows that nonutilities account for the largest percentage of facilities (2,205, or about 41 percent), but only represent 23 percent of total U.S. generating capacity. Investor-owned utilities operate the second largest number of facilities, 1,662, and generate 58 percent of total U.S. capacity.

Figure A3-1: Distribution of Facilities and Capacity by Ownership Type, 1999 [a]



[a] In order to best understand the landscape of the electric power generating market EPA tracked ownership changes from utilities to nonutilities, and vice versa, through January, 2002. These changes have been incorporated into the analysis where possible.

Source: U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c; U.S. DOE 1998c.

Plants owned and operated by utilities and nonutilities may be affected differently by the proposed Phase II rule due to differing competitive roles in the market. Much of the following discussion therefore differentiates between these two groups.

A3-2 Domestic Production

This section presents an overview of U.S. generating capacity and electricity generation. Subsection A3-2.1 provides data on capacity, and Subsection A3-2.2 provides data on generation. Subsection A3-2.3 presents an overview of the geographic distribution of generation plants and capacity.

[4] EPA tracked ownership changes from utilities to nonutilities, and vice versa, through January 2002. These changes are incorporated into the profile. As such, the universe of facilities (and their corresponding characteristics) is based on EIA 1999 data, adjusted to reflect EPA's most current knowledge.

A3-2.1 Generating Capacity[5]

Utilities own and operate the majority of the generating capacity in the United States (77 percent). Nonutilities owned only 23 percent of the total capacity in 1999 and produced roughly 21 percent of the electricity in the country. Nonutility capacity and generation have increased substantially in the past few years, however, since passage of legislation aimed at increasing competition in the industry. Nonutility capacity has increased by 247 percent between 1991 and 1998, compared with the decrease in utility capacity of eight percent over the same time period.[6]

Figure A3-2 shows the growth in utility and nonutility capacity from 1991 to 1999. The growth in nonutility capacity, combined with a slight decrease in utility capacity, has resulted in a modest growth in total generating capacity. The significant increase in nonutility capacity, and decrease in utility capacity in 1999 is attributable to utilities being sold to nonutilities.

CAPACITY/CAPABILITY

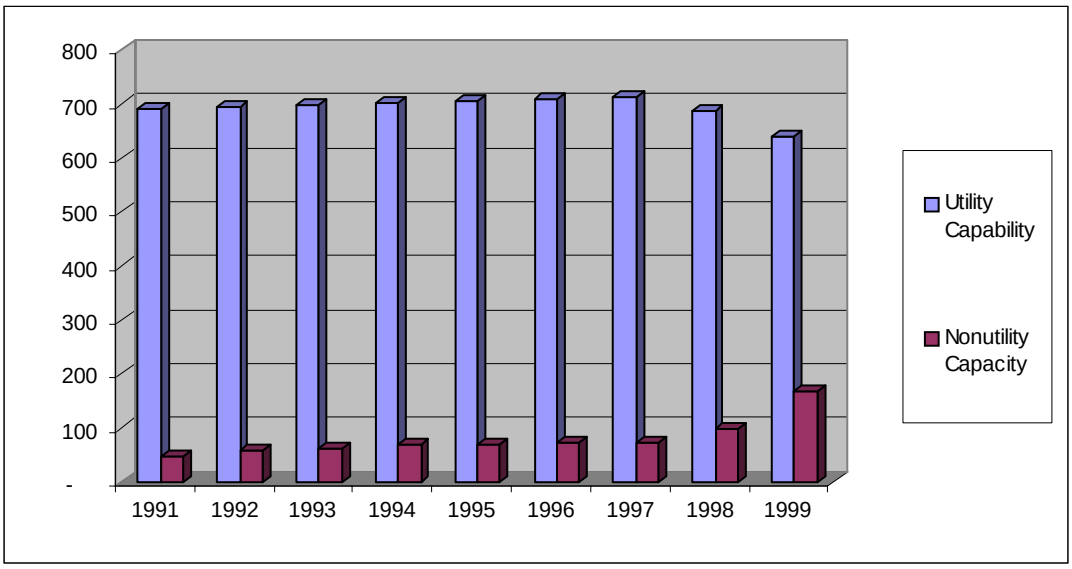
The rating of a generating unit is a measure of its ability to produce electricity. Generator ratings are expressed in megawatts (MW). Capacity and capability are the two common measures:

Nameplate capacity is the full-load continuous output rating of the generating unit under specified conditions, as designated by the manufacturer.

Net capability is the steady hourly output that the generating unit is expected to supply to the system load, as demonstrated by test procedures. The capability of the generating unit in the summer is generally less than in the winter due to high ambient-air and cooling-water temperatures, which cause generating units to be less efficient. The nameplate capacity of a generating unit is generally greater than its net capability.

U.S. DOE, 2000a

Figure A3-2: Generating Capability & Capacity, 1991 to 1999[a]



Source: U.S. DOE, 2000c; U.S. DOE,1996b.

[5] The numbers presented in this section are *capability* for utilities and *capacity* for nonutilities (see text box for the difference between these two measures). For convenience purposes, this section will refer to both measures as"capacity."

[6] More accurate data were available starting in 1991, therefore, 1991 was selected as the initial year for trends analysis.

A3-2.2 Electricity Generation

Total net electricity generation in the U.S. for 1999 was 3,723 billion kWh. Utility-owned plants accounted for 85 percent of this amount. Total net generation has increased by 21 percent over the nine-year period from 1991 to 1999. During this period, nonutilities increased their electricity generation by 131 percent. In comparison, generation by utilities increased by only 12 percent (U.S. DOE, 2000b; U.S. DOE, 2000c; U.S. DOE, 1995a; U.S. DOE, 1995b). This trend is expected to continue with deregulation in the coming years, as more facilities are purchased and built by nonutility power producers.

Table A3-2 shows the change in net generation between 1991 and 1999 by fuel source for utilities and nonutilities.

MEASURES OF GENERATION

The production of electricity is referred to as generation and is measured in ***kilowatthours (kWh)***. Generation can be measured as:

Gross generation: The total amount of power produced by an electric power plant.

Net generation: Power available to the transmission system beyond that needed to operate plant equipment. For example, around 7% of electricity generated by steam electric units is used to operate equipment.

Electricity available to consumers: Power available for sale to customers. Approximately 8 to 9 percent of net generation is lost during the transmission and distribution process.

U.S. DOE, 2000a

Table A3-2: Net Generation by Energy Source and Ownership Type, 1991 to 1999 (GWh)

Energy Source	Utilities			Nonutilities[a]			Total		
	1991	1999	% Change	1991	1999	% Change	1991	1999	% Change
Coal	1,551	1,768	14%	39	126	219%	1,591	1,893	19%
Hydropower	280	294	5%	6	22	248%	286	315	10%
Nuclear	613	725	18%	0	9	0%	613	734	20%
Petroleum	111	87	-22%	8	21	181%	119	108	-9%
Gas	264	296	12%	127	296	132%	392	592	51%
Renewables[b]	10	4	-63%	57	76	33%	67	80	19%
Total	**2,830**	**3,174**	**12%**	**238**	**549**	**131%**	**3,067**	**3,723**	**21%**

[a] Nonutility generation was converted from gross to net generation based on prime mover-specific conversion factors (U.S. DOE, 2000c). As a result of this conversion, the total net generation estimates differ slightly from EIA published totals by fuel type.

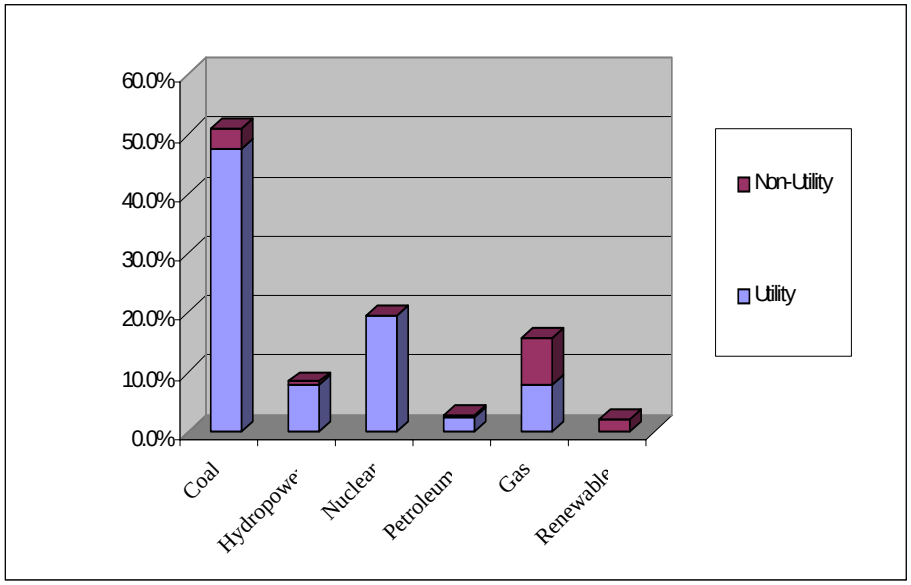
[b] Renewables include solar, wind, wood, biomass, and geothermal energy sources.

Source: U.S. DOE, 2000b;U.S. DOE, 2000c; U.S. DOE, 1995a; U.S. DOE,1995b.

As shown in Table A3-2, nuclear generation grew the fastest among the utility fuel source categories, increasing by 18 percent between 1991 and 1999. Coal generation increased by 14 percent, while gas generation increased by 12 percent. Utility generation from renewable energy sources decreased significantly (63 percent) between 1991 and 1999. A majority of this decline (48 percent) occurred from 1998 to 1999. Nonutility generation has grown at a much higher rate between 1991 and 1999 with the passage of legislation aimed at increasing competition in the industry. Nonutility hydroelectric generation grew the fastest among the energy source categories, increasing 248 percent between 1991 and 1999. Generation from coal-fired facilities also increased substantially, with a 219 percent increase in generation between 1991 and 1999.

Figure A3-3 shows total net generation for the U.S. by primary fuel source for utilities and nonutilities. Electricity generation from coal-fired plants accounts for 47 percent of total 1999 generation. Electric utilities generate 93 percent (1,768 billion kWh) of the 1,893 billion kWh of electricity generated by coal-fired plants. This represents approximately 56 percent of total utility generation. The remaining 7 percent (126 billion kWh) of coal-fired generation is provided by nonutilities, accounting for 23 percent of total nonutility generation. The second largest source of electricity generation is nuclear power plants, accounting for 20 percent of both total generation and total utility generation. Figure A3-3 shows that virtually 99.8 percent of nuclear generation is owned and operated by utilities. Another significant source of electricity generation is gas-fired power plants, which account for 54 percent of nonutility generation and 16 percent of total generation.

Figure A3-3: Percent of Electricity Generation by Primary Fuel Source, 1999



Source: U.S. DOE,2000b; U.S. DOE,2000c.

The proposed Phase II rule will affect facilities differently based on the fuel sources and prime movers used to generate electricity. As mentioned in Section A3-1.2 above, only prime movers with a steam electric generating cycle use substantial amounts of cooling water.

A3-2.3 Geographic Distribution

Electricity is a commodity that cannot be stored or easily transported over long distances. As a result, the geographic distribution of power plants is of primary importance to ensure a reliable supply of electricity to all customers. The U.S. bulk power system is composed of three major networks, or power grids:

- the *Eastern Interconnected System*, consisting of one third of the U.S., from the east coast to east of the Missouri River;
- the *Western Interconnected System*, west of the Missouri River, including the Southwest and areas west of the Rocky Mountains; and
- the *Texas Interconnected System*, the smallest of the three, consisting of the majority of Texas.

The Texas system is not connected with the other two systems, while the other two have limited interconnection to each other. The Eastern and Western systems are integrated or have links to the Canadian grid system. The Western and Texas systems have links with Mexico.

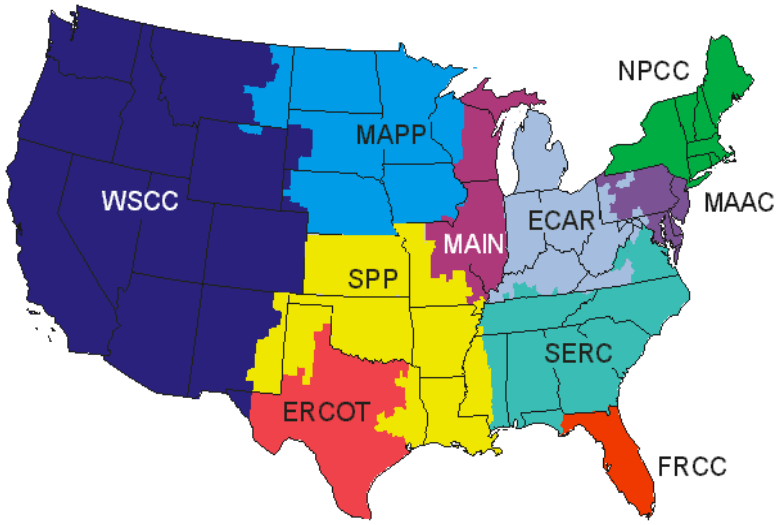
These major networks contain extra-high voltage connections that allow for power transactions from one part of the network to another. Wholesale transactions can take place within these networks to reduce power costs, increase supply options, and ensure system reliability. ***Reliability*** refers to the ability of power systems to meet the demands of consumers at any given time. Efforts to enhance reliability reduce the chances of power outages.

The North American Electric Reliability Council (NERC) is responsible for the overall reliability, planning, and coordination of the power grids. This voluntary organization was formed in 1968 by electric utilities, following a 1965 blackout in the Northeast. NERC is organized into nine regional councils that cover the 48 contiguous states, Hawaii, part of Alaska, and portions of Canada and Mexico. These regional councils are responsible for the overall coordination of bulk power policies that affect their regions' reliability and quality of service. Each NERC region deals with electricity reliability issues in its region, based on available capacity and transmission constraints. The councils also aid in the exchange of information among member utilities in each region and among regions. Service areas of the member utilities determine the boundaries of the NERC regions. Though limited by the larger bulk power grids described in the previous section, NERC regions do not necessarily follow any state boundaries. Figure A3-4 below provides a map of the NERC regions, which include:

- ECAR – East Central Area Reliability Coordination Agreement
- ERCOT – Electric Reliability Council of Texas
- FRCC – Florida Reliability Coordinating Council
- MAAC – Mid-Atlantic Area Council
- MAIN – Mid-America Interconnect Network
- MAPP – Mid-Continent Area Power Pool (U.S.)
- NPCC – Northeast Power Coordinating Council (U.S.)
- SERC – Southeastern Electric Reliability Council
- SPP – Southwest Power Pool
- WSCC – Western Systems Coordinating Council (U.S.)

Alaska and Hawaii are not shown in Figure A3-4. Part of Alaska is covered by the Alaska Systems Coordinating Council (ASCC), an affiliate NERC member. The state of Hawaii also has its own reliability authority (HI).

Figure A3-4: North American Electric Reliability Council (NERC) Regions



Source: EIA, 1996.

The proposed Phase II rule may affect plants located in different NERC regions differently. Economic characteristics of existing facilities affected by the proposed Phase II rule are likely to vary across regions by fuel mix, and the costs of fuel,

transportation, labor, and construction. Baseline differences in economic characteristics across regions may influence the impact of the proposed Phase II rule on profitability, electricity prices, and other impact measures. However, as discussed in *Chapter B3: Electricity Market Model Analysis*, the proposed Phase II rule will have little or no impact on electricity prices in each region since the proposed Phase II rule is relatively inexpensive relative to the overall production costs in any region.

Table A3-3 shows the distribution of all existing utilities, utility-owned plants, and capacity by NERC region. The table shows that while the Mid-Continent Area Power Pool (MAPP) has the largest number of utilities, 24 percent, these utilities only represent five percent of total capacity. Conversely, only five percent of the nation's utilities are located in the Southeastern Electric Reliability Council (SERC), yet these utilities are generally larger and account for 23 percent of the industry's total generating capacity.

Table A3-3: Distribution of Existing Generation Utilities, Utility Plants, and Capacity by NERC Region, 1999

NERC Region	Generation Utilities		Utility Plants		Capacity	
	Number	% of Total	Number	% of Total	Total MW	% of Total
ASCC	52	6%	168	5%	2,019	0%
ECAR	100	11%	301	10%	112,439	16%
ERCOT	28	3%	107	3%	55,908	8%
FRCC	18	2%	62	2%	38,155	5%
HI	3	0%	16	1%	1,592	0%
MAAC	21	2%	93	3%	23,649	3%
MAIN	65	7%	207	7%	45,120	6%
MAPP	212	24%	406	13%	36,094	5%
NPCC	73	8%	394	13%	45,948	7%
SERC	43	5%	333	11%	164,235	23%
SPP	144	16%	262	8%	45,782	7%
WSCC	129	14%	773	25%	131,644	19%
Unknown	3	0%	3	0%	39	0%
Total	**891**	**100%**	**3,125**	**100%**	**702,624**	**100%**

Source: U.S. DOE, 1999a; U.S. DOE, 1999c.

Table A3-4 shows the distribution of existing nonutility plants and capacity by NERC region. The table shows that the Western Systems Coordinating Council (WSCC) has the largest number of nonutility plants, with 613. MAAC, which contains only 7 percent of the total number of nonutility plants, accounts for the largest portion of capacity, with 43,547 MW (21 percent).

Table A3-4: Distribution of Nonutility Plants and Capacity by NERC Region, 1999

NERC Region	Nonutility Plants		Capacity	
	Number	% of Total	Total MW	% of Total
ASCC	26	1%	300	0%
ECAR	139	6%	8,883	4%
ERCOT	75	3%	9,525	5%
FRCC	57	3%	4,173	2%
HI	11	0%	740	0%
MAAC	155	7%	43,547	21%
MAIN	136	6%	30,398	15%
MAPP	70	3%	1,599	1%
NPCC	531	24%	39,720	19%
SERC	279	13%	16,293	8%
SPP	43	2%	1,844	1%
WSCC	613	28%	39,894	19%
Unknown	70	3%	9,584	5%
Total	**2,205**	**100%**	**206,500**	**100%**

Source: U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c.

A3-3 Existing Plants with CWIS and NPDES Permit

Section 316(b) of the Clean Water Act applies to a point source facility uses or proposes to use a cooling water intake structure water that directly withdraws cooling water from a water of the United States. Among power plants, only those facilities employing a steam electric generating technology require cooling water and are therefore of interest to this analysis. Steam electric generating technologies include units with steam electric turbines and combined-cycle units with a steam component.

The following sections describe existing utility and nonutility power plants that would be subject to the proposed Phase II rule. The Proposed Section 316(b) Phase II Existing Facilities Rule applies to existing steam electric power generating facilities that meet all of the following conditions:

- They meet the definition of an existing steam electric power generating facility as specified in § 125.93 of this rule;
- They use a cooling water intake structure or structures, or obtain cooling water by any sort of contract or arrangement with an independent supplier who has a cooling water intake structure;
- Their cooling water intake structure(s) withdraw(s) cooling water from waters of the U.S., and at least twenty-five (25) percent of the water withdrawn is used for contact or non-contact cooling purposes;
- They have an NPDES permit or are required to obtain one; and
- They have a design intake flow of 50 MGD or greater.

The proposed Phase II rule also covers substantial additions or modifications to operations undertaken at such facilities. While all facilities that meet these criteria are subject to the regulation, this Economic and Benefit Analysis (EBA) focuses on 539 utility and non-utility steam electric power generating facilities identified in EPA's 2000 Section 316(b) Industry Survey as being "in-scope" of this proposed rule. These 539 facilities represent 550 facilities nation-wide.[7] The remainder of this chapter will refer to these facilities as "existing section 316(b) plants."

Utilities and nonutilities are discussed in separate subsections because the data sources, definitions, and potential factors influencing the magnitude of impacts are different for the two sectors. Each subsection presents the following information:

- ***Ownership type:*** This section discusses existing section 316(b) facilities with respect to the entity that owns them. Utilities are classified into investor-owned utilities, rural electric cooperatives, municipalities, and other publicly-owned utilities (see Section A3-1.3). This differentiation is important because EPA has separately considered impacts on governments in its regulatory development (see *Chapter B9: UMRA Analysis* for the analysis of government impacts of the proposed Phase II rule). The utility ownership categories do not apply to nonutilities. The ownership type discussion for nonutilities differentiates between two types of plants: (1) plants that were originally built by nonutility power producers ("original nonutility plants") and (2) plants that used to be owned by utilities but that were sold to nonutilities as a result of industry deregulation ("former utility plants"). Differentiation between these two types of nonutilities is important because of their different economic and operational characteristics.

- ***Ownership size:*** This section presents information on the Small Business Administration (SBA) entity size of the owners of existing section 316(b) facilities. EPA has considered economic impacts on small entities when developing this regulation (see *Chapter B4: Regulatory Flexibility Analysis* for the small entity analysis of new facilities subject to the proposed Phase II rule).

- ***Plant size:*** This section discusses the existing section 316(b) facilities by the size of their generation capacity. The size of a plant is important because it partly determines its need for cooling water.

- ***Geographic distribution:*** This section discusses plants by NERC region. The geographic distribution of facilities is important because a high concentration of facilities with costs under a regulation could lead to impacts on a regional level. Everything else being equal, the higher the share of plants with costs, the higher the likelihood that there may be economic and/or system reliability impacts as a result of the regulation.

- ***Water body and cooling system type:*** This section presents information on the type of water body from which existing section 316(b) facilities draw their cooling water and the type of cooling system they operate. Cooling systems can be either once-through or recirculating systems.[8] Plants with once-through cooling water systems withdraw between 70 and 98 percent more water than those with recirculating systems.

Water Use by Steam Electric Power Plants

Steam electric generating plants are the single largest industrial users of water in the United States. In 1995:

- steam electric plants withdrew an estimated 190 billion gallons per day, accounting for 39 percent of freshwater use and 47 percent of combined fresh and saline water withdrawals for offstream uses (uses that temporarily or permanently remove water from its source);
- fossil-fuel steam plants accounted for 71 percent of the total water use by the power industry;
- nuclear steam plants and geothermal plants accounted for 29 percent and less than 1 percent, respectively;
- surface water was the source for more than 99 percent of total power industry withdrawals;
- approximately 69 percent of water intake by the power industry was from freshwater sources, 31 percent was from saline sources.

USGS, 1995

[7] EPA applied sample weights to the 539 facilities to account for non-sampled facilities and facilities that did not respond to the survey. For more information on EPA's 2000 Section 316(b) Industry Survey, please refer to the Information Collection Request (U.S. EPA 2000).

[8] Once-through cooling systems withdraw water from the water body, run the water through condensers, and discharge the water after a single use. Recirculating systems, on the other hand, reuse water withdrawn from the source. These systems take new water into the system only to replenish losses from evaporation or other processes during the cooling process. Recirculating systems use cooling towers or ponds to cool water before passing it through condensers again.

A3-3.1 Existing Section 316(b) Utility Plants

EPA identified steam electric prime movers that require cooling water using information from the EIA data collection U.S. DOE, 1999a.[9] These prime movers include:

- Atmospheric Fluidized Bed Combustion (AB)
- Combined-Cycle Steam Turbine with Supplementary Firing (CA)
- Combined Cycle - Total Unit (CC)
- Steam Turbine – Common Header (CH)
- Combined-Cycle – Single Shaft (CS)
- Combined-Cycle Steam Turbine – Waste Heat Boiler Only (CW)
- Steam Turbine – Geothermal (GE)
- Integrated Coal Gasification Combined-Cycle (IG)
- Steam Turbine – Boiling Water Nuclear Reactor (NB)
- Steam Turbine – Graphite Nuclear Reactor (NG)
- Steam Turbine – High Temperature Gas-Cooled Nuclear Reactor (NH)
- Steam Turbine – Pressurized Water Nuclear Reactor (NP)
- Steam Turbine – Solar (SS)
- Steam Turbine – Boiler (ST)

Using this list of steam electric prime movers, and U.S. DOE, 1999a information on the reported operating status of units, EPA identified 862 facilities that have at least one generating unit with a steam electric prime mover. Additional information from the section 316(b) Industry Surveys was used to determine that 416 of the 862 facilities operate a CWIS and hold an NPDES permit. Table A3-5 provides information on the number of utilities, utility plants, and generating units, and the generating capacity in 1999. The table provides information for the industry as a whole, for the steam electric part of the industry, and for the part of the industry potentially affected by the proposed Phase II rule.

Table A3-5: Number of Existing Utilities, Utility Plants, Units, and Capacity, 1999

	Total[a]	Steam Electric[b]		Steam Electric with CWIS and NPDES Permit[c]	
		Number	% of Total	Number	% of Total
Utilities	891	315	35%	148	17%
Plants	3,125	862	28%	416	13%
Units	10,460	2,226	21%	1,220	12%
Nameplate Capacity (MW)	702,624	533,503	76%	344,849	49%

[a] Includes only generating capacity not permanently shut down or sold to nonutilities.
[b] Utilities and plants are listed as steam electric if they have at least one steam electric unit.
[c] The number of plants, units, and capacity was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999c.

Table A3-5 shows that the while the 862 steam electric plants account for only 28 percent of all plants, these plants account for 76 percent of all capacity. The 416 in-scope plants represent 13 percent of all plants, are owned by 17 percent of all utilities, and account for approximately 49 percent of reported utility generation capacity. The remainder of this section will focus on the 416 utility plants.

[9] U.S. DOE, 1999a (Annual Electric Generator Report) collects data used to create an annual inventory of utilities. The data collected includes: type of prime mover; nameplate rating; energy source; year of initial commercial operation; operating status; cooling water source, and NERC region.

a. Ownership type

Table A3-6 shows the distribution of the 148 utilities that own the 416 existing section 316(b) plants, as well as the total generating capacity of these entities, by type of ownership. The table also shows the total number of plants, utilities, and capacity by type of ownership. Utilities can be divided into three major ownership categories: investor-owned utilities, publicly-owned utilities (including municipalities, political subdivision, and federal and state-owned utilities), and rural electric cooperatives. Table A3-6 shows that approximately 19 percent of plants operated by investor-owned utilities have a CWIS and an NPDES permit. These 313 facilities account for 75 percent of all existing plants with a CWIS and an NPDES permit (313 divided by 416). The percentage of all plants that have a CWIS and an NPDES permit is lower for the other ownership types: 12 percent for rural electric cooperatives, six percent for municipalities, and seven percent for other publicly owned utilities.

Table A3-6: Existing Utilities, Plants, and Capacity by Ownership Type, 1999[a]

Ownership Type	Utilities			Plants			Capacity (MW)		
	Total Number of Utilities	Utilities with Plants with CWIS and NPDES		Total Number of Plants	Plants with CWIS and NPDES[b]		Total Capacity	Capacity with CWIS and NPDES[b]	
		Number	% of Total		Number	% of Total		MW	% of Total
Investor-Owned	177	88	50%	1,662	313	19%	527,948	287,774	55%
Coop	71	14	20%	213	25	12%	28,151	8,582	30%
Municipal	578	38	7%	867	50	6%	42,904	15,870	37%
Other Public	65	8	12%	383	27	7%	103,621	32,623	31%
Total	**891**	**148**	**17%**	**3,125**	**416**	**13%**	**702,624**	**344,850**	**68%**

[a] Numbers may not add up to totals due to independent rounding.
[b] The number of plants and capacity was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999c.

b. Ownership size

EPA used the Small Business Administration (SBA) small entity size standards for SIC code 4911 (electric output of four million megawatt hours or less per year) to make the small entity determination.[10] Table A3-7 provides information on the total number of utilities and utility plants owned by small entities by type of ownership. The table shows that 26 of the 148 utilities with existing section 316(b) plants, or 18 percent, may be small. The size distribution varies considerably by ownership type: only 13 percent of all other public utilities and zero percent of all investor-owned utilities with existing section 316(b) plants may be small, compared to 43 percent of all coop and 50 percent of all municipalities. The same is true on the plant level: none of the 313 existing section 316(b) plants operated by an investor-owned utility, and four percent of the other publicly owned utilities are owned by a small entity. The corresponding percentages for municipalities and electric cooperatives are 38 percent and 24 percent, respectively.[11]

Table A3-7 also shows the percentage of all small utilities and all plants owned by small utilities that comprise the "section 316(b)" part of the industry. Twenty-six, or four percent, of all 697 small utilities operate existing section 316(b) plants. At the plant level, between one percent (other public) and four percent (Coop) of small utility plants have CWIS and NPDES permits.

Table A3-7: Existing Small Utilities and Utility Plants by Ownership Type, 1999

Ownership Type	Total				With CWIS and NPDES Permit [a,b]				Small with CWIS and NPDES/ Total Small
	Total	Small	Unknown	% Small	Total	Small	Unknown	% Small	
Utilities									
Investor-Owned	177	47	11	27%	88	0	0	0%	0%
Coop	71	54	1	76%	14	6	0	43%	11%
Municipal	578	557	11	96%	38	19	2	50%	3%
Other Public	65	39	9	60%	8	1	0	13%	3%
Total	**891**	**697**	**32**	**78%**	**148**	**26**	**2**	**18%**	**4%**
Plants									
Investor-Owned	1,662	211	26	13%	313	0	0	0%	0%
Coop	213	154	0	72%	25	6	0	24%	4%
Municipal	867	781	9	90%	50	19	2	38%	2%
Other Public	383	136	71	36%	27	1	0	4%	1%
Total	**3,125**	**1,282**	**106**	**41%**	**416**	**26**	**2**	**11%**	**2%**

[a] Numbers may not add up to totals due to independent rounding.
[b] The number of plants was sample weighted to account for survey non-respondents.

Source: U.S. SBA, 2000; U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999c; U.S. DOE 1999d.

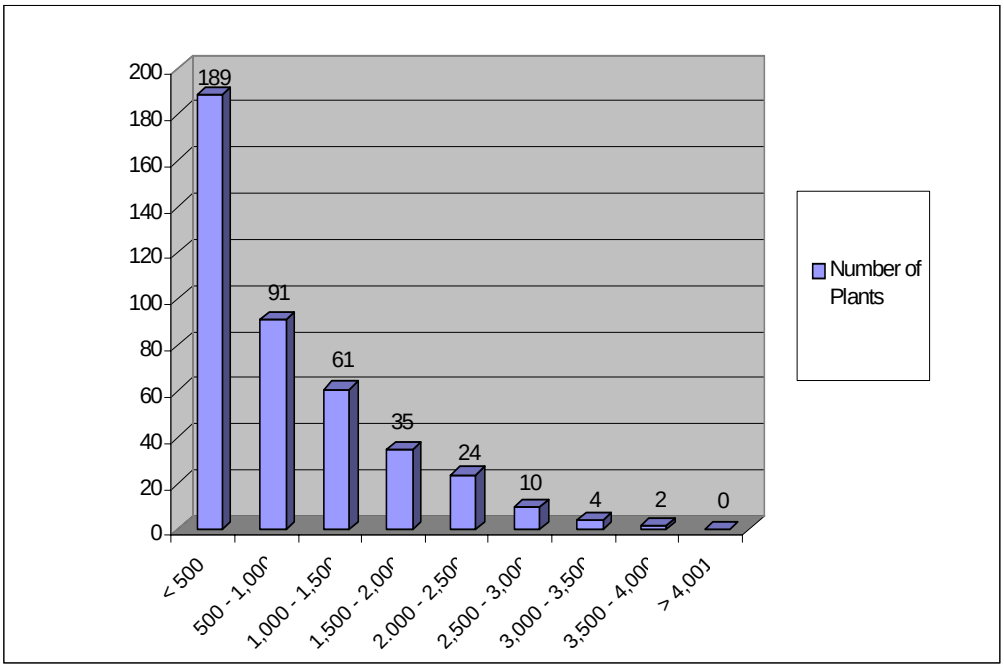
[10] SBA defines "small business" as a firm with an annual electricity output of four million MWh or less and "small governmental jurisdictions" as governments of cities, counties, towns, school districts, or special districts with a population of less than 50,000 people. Information on the population of all municipal utilities was not readily available for all municipalities. EPA therefore used the small business standard for all utilities.

[11] Note that for investor-owned utilities, the small business determination is generally made at the holding company level. Holding company information was not available for all investor-owned utilities. The small business determination was therefore made at the utility level. This approach will overstate the number of investor-owned utilities and their plants that are classified as small.

c. Plant size

EPA also analyzed the steam electric facilities with a CWIS and an NPDES permit with respect to their generating capacity. Figure A3-5 presents the distribution of existing utility plants with a CWIS and an NPDES permit by plant size. Of the 416 plants, 189 (45 percent) have a total nameplate capacity of 500 megawatts or less, and 280 (67 percent) have a total capacity of 1,000 megawatts or less.

Figure A3-5: Number of Existing Phase II Facilities by Plant Size (in MW), 1999 [a,b]



[a] Numbers may not add up to totals due to independent rounding.
[b] The number of plants was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999c.

d. Geographic distribution

Table A3-8 shows the distribution of existing section 316(b) utility plants by NERC region. The table shows that there are considerable differences between the regions in terms of both the number of existing utility plants with a CWIS and an NPDES permit, and the percentage of all plants that they represent. Excluding Alaska, which only has one utility plant with a CWIS and an NPDES permit, the percentage of existing section 316(b) facilities ranges from two percent in the Western Systems Coordinating Council (WSCC) to 49 percent in the Electric Reliability Council of Texas (ERCOT). The Southeastern Electric Reliability Council (SERC) has the highest absolute number of existing section 316(b) facilities with 94, or 23 percent of all facilities, followed by the East Central Area Reliability Coordination Agreement (ECAR) with 90 facilities, or 22 percent of all facilities.

Table A3-8: Existing Utility Plants by NERC Region, 1999

NERC Region	Total Number of Plants	Plants with CWIS and NPDES Permit[a,b]	
		Number	% of Total
ASCC	168	1	1%
ECAR	301	90	30%
ERCOT	107	52	49%
FRCC	62	29	47%
HI	16	3	19%
MAAC	93	3	3%
MAIN	207	33	16%
MAPP	406	43	11%
NPCC	394	17	4%
SERC	333	94	28%
SPP	262	32	12%
WSCC	773	18	2%
Unknown	3	0	0%
Total	**3,125**	**416**	**13%**

[a] Numbers may not add up to totals due to independent rounding.
[b] The number of plants was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999c.

e. Water body and cooling system type

Table A3-9 shows that most of the existing utility plants with a CWIS and an NPDES permit draw water from a freshwater river (204, or 49 percent). The next most frequent water body types are lakes or reservoirs with 138 plants (33 percent) and estuaries or tidal rivers with 47 plants (11 percent). The table also shows that most of these plants, 314 or 75 percent, employ a once-through cooling system. Of the plants that withdraw from an estuary, the most sensitive type of water body, only nine percent use a recirculating system while 85 percent have a once-through system.

Table A3-9: Number of Existing Utility Plants by Water Body Type and Cooling System Type[a]

Water Body Type	Cooling System Type										
	Recirculating		Once-Through		Combination		Other		Unknown		Total [b]
	No.	% of Total	No.	% of Total	No.	% of Total	No.	% of Total	No.	% of Total	
Estuary/ Tidal River	4	9%	40	85%	1	2%	2	4%	0	0%	**47**
Ocean	0	0%	15	100%	0	0%	0	0%	0	0%	**15**
Lake/ Reservoir	29	21%	103	75%	4	3%	2	1%	0	0%	**138**
Freshwater River	36	18%	149	73%	8	4%	10	5%	1	0%	**204**
Multiple Freshwater	0	0%	6	60%	3	30%	1	10%	0	0%	**10**
Other/ Unknown	1	50%	1	50%	0	0%	0	0%	0	0%	**2**
Total	**70**	**17%**	**314**	**75%**	**16**	**4%**	**15**	**4%**	**1**	**0%**	**416**

[a] The number of plants was sample weighted to account for survey non-respondents.
[b] Numbers may not add up to totals due to independent rounding.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999c.

A3-3.2 Existing Section 316(b) Nonutility Plants

EPA identified nonutility steam electric prime movers that require cooling water using information from the EIA data collection Forms EIA-860B[12] and the section 316(b) Industry Survey. These prime movers include:

- Geothermal Binary (GB)
- Steam Turbine – Fluidized Bed Combustion (SF)
- Solar – Photovoltaic (SO)
- Steam Turbine (ST)

In addition, prime movers that are part of a combined-cycle unit were classified as steam electric.

U.S. DOE, 1998b includes two types of nonutilities: facilities whose primary business activity is the generation of electricity, and manufacturing facilities that operate industrial boilers in addition to their primary manufacturing processes. The discussion of existing section 316(b) nonutilities focuses on those nonutility facilities that generate electricity as their primary line of business.

[12] U.S. DOE, 1998b (Annual Nonutility Electric Generator Report) is the equivalent of U.S. DOE, 1998a for utilities. It is the annual inventory of nonutility plants and collects data on the type of prime mover, nameplate rating, energy source, year of initial commercial operation, and operating status.

Using the identified list of steam electric prime movers, and U.S. DOE, 1999b information on the reported operating status of generating units, EPA identified 559 facilities that have at least one generating unit with a steam electric prime mover. Additional information from the section 316(b) Industry Survey determined that 134 of the 559 facilities operate a CWIS and hold an NPDES permit. Table A3-10 provides information on the number of parent entities, nonutility plants, and generating units, and their generating capacity in 1999. The table provides information for the industry as a whole, for the steam electric part of the industry, and for the "section 316(b)" part of the industry.

Table A3-10: Number of Nonutilities, Nonutility Plants, Units, and Capacity, 1999

	Total	Total Steam Electric Nonutilities [a]	Nonutilities with CWIS and NPDES Permit[a,b]	
			Number	% of Steam Electric
Parent Entities	1,509	441	47	11%
Nonutility Plants	2,205	559	134	24%
Nonutility Units	5,958	1,255	343	27%
Nameplate Capacity (MW)	206,500	153,032	107,054	70%

[a] Includes only nonutility plants generating electricity as their primary line of business.
[b] The number of plants, units, and capacity was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c.

a. Ownership type

Nonutility power producers that generate electricity as their main line of business fall into two different categories: "original nonutility plants" and "former utility plants."

❖ *Original nonutility plants*

For the purposes of this analysis, original nonutility plants are those that were originally built by a nonutility. These plants primarily include facilities qualifying under the Public Utility Regulatory Policies Act of 1978 (PURPA), cogeneration facilities, independent power producers, and exempt wholesale generators under the Energy Policy Act of 1992 (EPACT).

EPA identified original nonutility plants with a CWIS and an NPDES permit through the section 316(b) Industry Survey. This profile further differentiates original nonutility plants by their primary Standard Industrial Classification (SIC) code, as reported in the section 316(b) Industry Survey. Reported SIC codes include:

- 4911 – Electric Services
- 4931 – Electric and Other Services Combined
- 4939 – Combination Utilities, Not Elsewhere Classified
- 4953 – Refuse Systems

❖ *Former utility plants*

Former utility plants are those that used to be owned by a utility power producer but have been sold to a nonutility as a result of industry deregulation. These were identified from U.S. DOE, 1999a, by their plant code, section 316(b) Industry Survey, and research conducted through January 2002.[13]

Table A3-11 shows that original nonutilities account for the vast majority of plants (1,894 out of 2,205, or 86 percent). Only 311 out of the 2,205 nonutility plants, or 14 percent, were formerly owned by utilities. However, these 311 facilities account for about 63 percent of all nonutility generating capacity (130,526 MW divided by 206,499 MW). One-hundred thirty-four of

[13] Plants formerly owned by a regulated utility have an identification code number that is less than 10,000 whereas nonutilities have a code number greater than 10,000. When utility plants are sold to nonutilities, they retain their original plant code. EPA tracked ownership changes from utilities to nonutilities, and vice versa, through January 2002. These changes are incorporated into the profile. As such, the universe of facilities (and their corresponding characteristics) is based on EIA 1999 data, adjusted to reflect EPA's most current knowledge.

the 2,205 nonutility plants operate a CWIS and hold an NPDES permit. Most of these section 316(b) facilities (120, or 91 percent) are former utility plants, and account for almost 99 percent of all section 316(b) nonutility capacity (105,672 MW divided by 107,054 MW). The table also shows that only one percent of all original nonutility plants have a CWIS and an NPDES permit,[14] compared to 49 percent of all former utility plants.

Table A3-11: Existing Nonutility Firms, Plants, and Capacity by SIC Code, 1998[a]

SIC Code	Firms			Plants			Capacity (MW)		
	Total Number of Firms[b]	Firms with Plants with CWIS and NPDES[b]		Total Number of Plants	Plants with CWIS and NPDES[b]		Total Capacity	Capacity with CWIS and NPDES[b]	
		Number	% of Total		Number	% of Total		MW	% of Total
Original Nonutilities									
4911	1,428	2	1%	1,894	2	1%	75,973	193	1%
4931		2			2			189	
4939		1			1			505	
4953		3			5			219	
Other SIC		3			3			252	
Former Utility Plants									
n/a	81	36	44%	311	120	39%	130,526	105,672	81%
Total	**1,509**	**47**	**3%**	**2,205**	**134**	**6%**	**206,499**	**107,030**	**52%**

[a] Numbers may not add up to totals due to independent rounding.
[b] The number of plants and capacity was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c.

[14] This percentage understates the true share of section 316(b) nonutility plants because the total number of plants includes industrial boilers while the number of section 316(b) nonutilities does not.

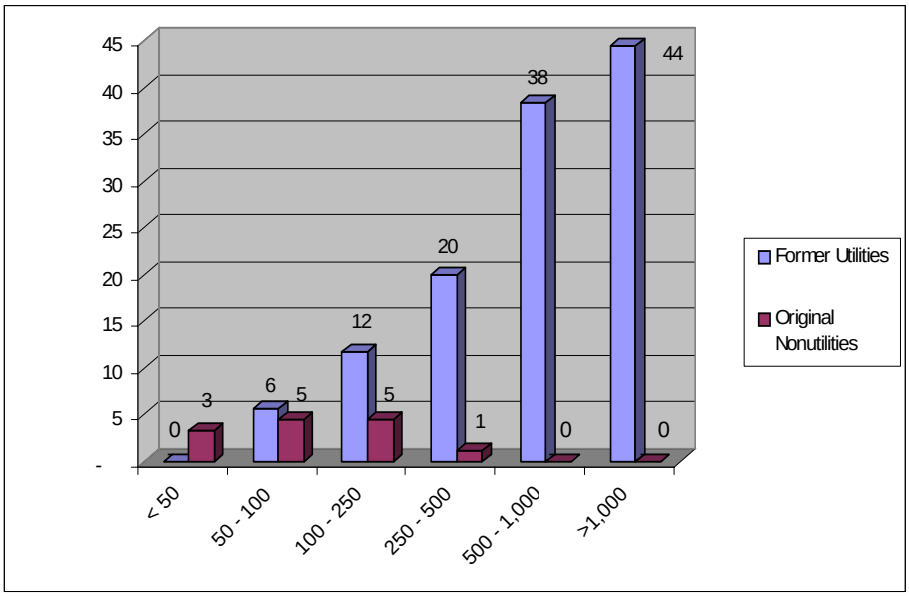
b. Ownership size

EPA used the Small Business Administration (SBA) small entity size standards to determine the number of existing section 316(b) nonutility plants owned by small firms. The thresholds used by EPA to determine if a domestic parent entity is small depend on the entity type. Since multiple entity types were analyzed, multiple data sources were needed to determine the entity sizes. EPA found that none of the parent entities of the 134 nonutility plants were small. For a detailed discussion of the identification and size determination of the parent entities please see *Chapter B4: Regulatory Flexibility Analysis.*

c. Plant size

EPA also analyzed the steam electric nonutilities with a CWIS and an NPDES permit with respect to their generating capacity. Figure A3-6 shows that the original nonutility plants are much smaller than the former utility plants. Of the 14 original utility plants, 3 (25 percent) have a total nameplate capacity of 50 MW or less, and 8 (58 percent) have a capacity of 100 MW or less. No original nonutility plant has a capacity of more than 500 MW. In contrast, only 18 (15 percent) former utility plants are smaller than 250 MW while 83 (69 percent) are larger than 500 MW and 44 (37 percent) are larger than 1,000 MW.

Figure A3-6: Number of Existing Nonutility Plants with CWIS and NPDES Permit by Generating Capacity (in MW), 1998[a,b]



[a] Numbers may not add up to totals due to independent rounding.
[a] The number of plants was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c.

d. Geographic distribution

Table A3-12 shows the distribution of existing section 316(b) nonutility plants by NERC region. The table shows that the Northeast Power Coordinating Council (NPCC) has the highest absolute number of existing section 316(b) nonutility plants with 45 (9 percent) of the 134 plants with a CWIS and an NPDES permit, followed by the Mid-Atlantic Area Council (MAAC) with 41 plants. MAAC also has the largest percentage of plants with a CWIS and an NPDES permit compared to all nonutility plants within the region, at 26 percent.[15]

Table A3-12: Nonutility Plants by NERC Region, 1998

NERC Region	Total Number of Plants	Plants with CWIS & NPDES Permit[a,b]	
		Number	% of Total
ASCC	26	0	0%
ECAR	139	10	7%
ERCOT	75	0	0%
FRCC	57	1	2%
HI	11	0	0%
MAAC	155	41	26%
MAIN	136	18	13%
MAPP	70	1	2%
NPCC	531	45	9%
SERC	279	1	0%
SPP	43	0	0%
WSCC	613	16	3%
Not Available	70	0	0%
Total	**2,205**	**134**	**6%**

[a] Numbers may not add up to totals due to independent rounding.
[b] The number of plants was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c.

[15] As explained earlier, the total number of plants includes industrial boilers while the number of plants with a CWIS and an NPDES permit does not. Therefore, the percentages are likely higher than presented.

e. Water body and cooling system type

Table A3-13 shows the distribution of existing section 316(b) nonutility plants by type of water body and cooling system. The table shows that for both original and former nonutilities, a majority of plants with a CWIS and an NPDES permit draw water from either a freshwater river, or an estuary or tidal river. Out of the 14 total original nonutilities, seven (50 percent) pull from a freshwater river, and six (42 percent) pull from an estuary or tidal river. Out of the 120 former utilities, 53 (44 percent) pull from a freshwater river, and 47 (39 percent) pull from an estuary or tidal river.

The table also shows that most of the nonutilities employ a once-through system: 13 out of 14 plants (92 percent) for original nonutilities and 101 out of 120 (84 percent) for former nonutility plants. Of the plants that withdraw from an estuary/tidal river, the most sensitive type of waterbody, only two use a recirculating system, while 50 (94 percent) operate a once-through system.

Table A3-13: Number of Nonutility Plants by Water Body Type and Cooling System Type[a]

Water Body Type	Cooling System Type								
	Recirculating		Once-Through		Combination		Other		Total [b]
	No.	% of Total	No.	% of Total	No.	% of Total	No.	% of Total	
Original Nonutilities									
Estuary/ Tidal River	0	0%	6	100%	0	0%	0	0%	6
Ocean	0	0%	0	0%	0	0%	0	0%	0
Lake/ Reservoir	0	0%	0	0%	1	100%	0	0%	1
Freshwater River	0	0%	7	100%	0	0%	0	0%	7
Other/ Unknown	0	0%	0	0%	0	0%	0	0%	0
Total	**0**	**0%**	**13**	**92%**	**1**	**8%**	**0**	**0%**	**14**
Former Utility Plants									
Estuary/ Tidal River	2	4%	50	94%	1	2%	0	0%	53
Ocean	0	0%	9	100%	0	0%	0	0%	9
Lake/ Reservoir	2	19%	9	81%	0	0%	0	0%	11
Freshwater River	13	29%	32	71%	0	0%	1	2%	46
Other/ Unknown	0	0%	1	100%	0	0%	0	0%	1
Total	**17**	**14%**	**101**	**84%**	**1**	**1%**	**1**	**1%**	**120**

[a] The number of plants was sample weighted to account for survey non-respondents.
[b] Numbers may not add up to totals due to independent rounding.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c.

A3-4 INDUSTRY OUTLOOK

This section discusses industry trends that are currently affecting the structure of the electric power industry and may therefore affect the magnitude of impacts from the proposed section 316(b) Phase II Rule. The most important change in the electric power industry is deregulation – the transition from a highly regulated monopolistic to a less regulated, more competitive industry. Subsection 3.4.1 discusses the current status of deregulation. Subsection 3.4.2 presents a summary of forecasts from the Annual Energy Outlook 2002.

A3-4.1 Current Status of Industry Deregulation

The electric power industry is evolving from a highly regulated, monopolistic industry with traditionally-structured electric utilities to a less regulated, more competitive industry.[16] The industry has traditionally been regulated based on the premise that the supply of electricity is a natural monopoly, where a single supplier could provide electric services at a lower total cost than could be provided by several competing suppliers. Today, the relationship between electricity consumers and suppliers is undergoing substantial change. Some states have implemented plans that will change the procurement and pricing of electricity significantly, and many more plan to do so during the first few years of the 21st century (Beamon, 1998).

a. Key changes in the industry's structure

Industry deregulation already has changed and continues to fundamentally change the structure of the electric power industry. Some of the key changes include:

- ***Provision of services:*** Under the traditional regulatory system, the generation, transmission, and distribution of electric power were handled by vertically-integrated utilities. Since the mid-1990s, federal and state policies have led to increased competition in the generation sector of the industry. Increased competition has resulted in a separation of power generation, transmission, and retail distribution services. Utilities that provide transmission and distribution services will continue to be regulated and will be required to divest of their generation assets. Entities that generate electricity will no longer be subject to geographic or rate regulation.

- ***Relationship between electricity providers and consumers:*** Under traditional regulation, utilities were granted a geographic franchise area and provided electric service to all customers in that area at a rate approved by the regulatory commission. A consumer's electric supply choice was limited to the utility franchised to serve their area. Similarly, electricity suppliers were not free to pursue customers outside their designated service territories. Although most consumers will continue to receive power through their local distribution company (LDC), retail competition will allow them to select the company that generates the electricity they purchase.

- ***Electricity prices:*** Under the traditional system, state and federal authorities regulated all aspects of utilities' business operations, including their prices. Electricity prices were determined administratively for each utility, based on the average cost of producing and delivering power to customers and a reasonable rate of return. As a result of deregulation, competitive market forces will set generation prices. Buyers and sellers of power will negotiate through power pools or one-on-one to set the price of electricity. As in all competitive markets, prices will reflect the interaction of supply and demand for electricity. During most time periods, the price of electricity will be set by the generating unit with the highest operating costs needed to meet spot market generation demand (i.e., the "marginal cost" of production) (Beamon, 1998).

b. New industry participants

The Energy Policy Act of 1992 (EPACT) provides for open access to transmission systems, to allow nonutility generators to enter the wholesale market more easily. In response to these requirements, utilities are proposing to form Independent System Operators (ISOs) to operate the transmission grid, regional transmission groups, and open access same-time information systems (OASIS) to inform competitors of available capacity on their transmission systems. The advent of open transmission access has fostered the development of power marketers and power brokers as new participants in the electric power industry. Power marketers buy and sell wholesale electricity and fall under the jurisdiction of the Federal Energy

[16] Several key pieces of federal legislation have made the changes in the industry's structure possible. The ***Public Utility Regulatory Policies Act (PURPA)*** of 1978 opened up competition in the generation market by creating a class of nonutility electricity-generating companies referred to as "qualifying facilities." The ***Energy Policy Act (EPACT)*** of 1992 removed constraints on ownership of electric generation facilities, and encouraged increased competition in the wholesale electric power business (Beamon, 1998).

Regulatory Commission (FERC), since they take ownership of electricity and are engaged in interstate trade. Power marketers generally do not own generation or transmission facilities or sell power to retail customers. A growing number of power marketers have filed with the FERC and have had rates approved. Power brokers, on the other hand, arrange the sale and purchase of electric energy, transmission, and other services between buyers and sellers, but do not take title to any of the power sold.

c. State activities

Many states have taken steps to promote competition in their electricity markets. The status of these efforts varies across states. Some states are just beginning to study what a competitive electricity market might mean; others are beginning pilot programs; still others have designed restructured electricity markets and passed enabling legislation. However, the difficult transition to a competitive electricity market in California, characterized by price spikes and rolling black-outs, has affected restructuring in that state and several others. Since those difficulties in 2000, a total of seven states (Arkansas, Montana, Nevada, New Mexico, Oklahoma, Oregon, and West Virginia) have delayed the restructuring process pending further review of the issues while California has suspended direct retail access. As of March 2002, the following states have either enacted restructuring legislation or issued a regulatory order to implement retail access (U.S. DOE, 2002):

- Arizona
- Connecticut
- Delaware
- District of Columbia
- Illinois
- Maine
- Maryland
- Massachusetts
- Michigan
- New Hampshire
- New Jersey
- New York
- Ohio
- Pennsylvania
- Rhode Island
- Texas
- Virginia

Even in states where consumer choice is available, important aspects of implementation may still be undecided. Key aspects of implementing restructuring include treatment of stranded costs, pricing of transmission and distribution services, and the design market structures required to ensure that the benefits of competition flow to all consumers (Beamon, 1998).

A3-4.2 Energy Market Model Forecasts

This section discusses forecasts of electric energy supply, demand, and prices based on data and modeling by the EIA and presented in the *Annual Energy Outlook 2002* (U.S. DOE, 2001)]. The EIA models future market conditions through the year 2020, based on a range of assumptions regarding overall economic growth, global fuel prices, and legislation and regulations affecting energy markets. The projections are based on the results from EIA's National Energy Modeling System (NEMS) using assumptions reflecting economic conditions as of July 2001. EPA used ICF Consulting's Integrated Planning Model (IPM®), an integrated energy market model, to conduct the economic analyses supporting the proposed section 316(b) Phase II Rule (see *Chapter B3: Electricity Market Model Analysis*). The IPM generates baseline and post compliance estimates of each of the measures discussed below. For purposes of comparison, this section presents a discussion of EIA's reference case results.

a. Electricity demand

The AEO2002 projects electricity demand to grow by approximately 1.8 percent annually between 2000 and 2020. This growth is driven by an estimated 2.3 percent annual increase in the demand for electricity from the commercial sector associated with a projected annual growth in commercial floor space. Residential demand is expected to increase by 1.7 percent annually as a result of an increase in the number of U.S. households of 1 percent per year between 2000 and 2020. EIA expects electricity demand from the industrial sector to increase by 1.4 percent annually over the same forecast period, largely in response to an increase in industrial output of 2.6 per year.

b. Capacity retirements

The AOE2002 projects total nuclear capacity to decline by an estimated 10 percent (or 10 gigawatts) between 2000 and 2020 due to nuclear power plant retirement. These closures are primarily assumed to be the result of the high costs of maintaining the performance of nuclear units compared with the cost of constructing the least cost alternative. EIA also expects total fossil fuel-fired generation capacity to decline due to retirements. EIA forecasrs that total fossil-steam capacity will decrease by an estimated 7 percent (or 37 gigawatts) over the same time period including 20 gigawatts of oil and natural gas fired steam capacity.

c. Capacity additions

Additional generation capacity will be needed to meet the estimated growth in electricity demand and offset the retirement of existing capacity. EIA expects utilities to employ other options, such as life extensions and repowering, to power imports from Canada and Mexico, and purchases from cogenerators before building new capacity. EIA forecasts that utilities will choose technologies for new generation capacity that seek to minimize cost while meeting environmental and emission constraints. Of the new capacity forecasted to come on-line between 2000 and 2020, 88 percent is projected to be combined-cycle technology or combustion turbine technology, including distributed generation capacity. This additional capacity is expected to be fueled by natural gas and to supply primarily peak and intermediate capacity. Approximately nine percent of the additional capacity forecasted to come on line between 2000 and 2020 is expected to be provided by new coal-fired plants, while the remaining three percent is forecasted to come from renewable technologies.

d. Electricity generation

The AEO2002 projects increased electricity generation from both natural gas and coal-fired plants to meet growing demand and to offset lost capacity due to plant retirements. The forecast projects that coal-fired plants will remain the largest source of generation throughout the forecast period. Although coal-fired generation is predicted to increase steadily between 2000 and 2020, its share of total generation is expected to decrease from 52 percent to an estimated 46 percent. This decrease in the share of coal generation is in favor of less capital-intensive and more efficient natural gas generation technologies. Investment in existing nuclear plants is expected to hold nuclear generation at current levels until 2006, after which it is forecast to decline as older units are retired. The share of total generation associated with gas-fired technologies is projected to increase from approximately 16 percent in 2001 to an estimated 32 percent in 2020, replacing nuclear power as the second largest source of electricity generation. Generation from oil-fired plants is expected to remain fairly small throughout the forecast period.

e. Electricity prices

EIA expects the average price of electricity, as well as the price paid by customers in each sector (residential, commercial, and industrial), to decrease between 2000 and 2020 as a result of competition among electricity suppliers. Specific market restructuring plans differ from state to state. Some states have begun deregulating their electricity markets; EIA expects most states to phase in increased customer access to electricity suppliers. Increases in the cost of fuels like natural gas and oil are not expected to increase electricity prices; these increases are expected to be offset by reductions in the price of other fuels and shifts to more efficient generating technologies.

GLOSSARY

Baseload: A baseload generating unit is normally used to satisfy all or part of the minimum or base load of the system and, as a consequence, produces electricity at an essentially constant rate and runs continuously. Baseload units are generally the newest, largest, and most efficient of the three types of units. (http://www.eia.doe.gov/cneaf/electricity/page/prim2/chapter2.html)

Combined-Cycle Turbine: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Distribution: The portion of an electric system that is dedicated to delivering electric energy to an end user.

Electricity Available to Consumers: Power available for sale to customers. Approximately 8 to 9 percent of net generation is lost during the transmission and distribution process.

Energy Policy Act (EPACT): In 1992 the EPACT removed constraints on ownership of electric generation facilities and encouraged increased competition on the wholesale electric power business.

Gas Combustion Turbine: A gas turbine typically consisting of an axial-flow air compressor and one or more combustion chambers, where liquid or gaseous fuel is burned and the hot gases are passed to the turbine. The hot gases expand to drive the generator and are then used to run the compressor.

Generation: The process of producing electric energy by transforming other forms of energy. Generation is also the amount of electric energy produced, expressed in watthours (Wh).

Gross Generation: The total amount of electric energy produced by the generating units at a generating station or stations, measured at the generator terminals.

Intermediate load: Intermediate-load generating units meet system requirements that are greater than baseload but less than peakload. Intermediate-load units are used during the transition between baseload and peak load requirements. (http://www.eia.doe.gov/cneaf/electricity/page/prim2/chapter2.html)

Internal Combustion Engine: An internal combustion engine has one or more cylinders in which the process of combustion takes place, converting energy released from the rapid burning of a fuel-air mixture into mechanical energy. Diesel or gas-fired engines are the principal fuel types used in these generators.

Kilowatthours (kWh): One thousand ***watthours (Wh)***.

Nameplate Capacity: The amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated by the manufacturer.

Net Capacity: The amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated by the manufacturer, exclusive of station use, and unspecified conditions for a given time interval.

Net Generation: Gross generation minus plant use from all plants owned by the same utility.

Nonutility: A corporation, person, agency, authority, or other legal entity or instrumentality that owns electric generating capacity and is not an electric utility. Nonutility power producers include qualifying cogenerators, qualifying small power producers, and other nonutility generators (including independent power producers) without a designated franchised service area that do not file forms listed in the Code of Federal Regulations, Title 18, Part 141. (http://www.eia.doe.gov/emeu/iea/glossary.html)

Other Prime Movers: Methods of power generation other than ***steam turbine***, ***combined-cycle***, ***gas combustion turbine***, ***internal combustion engine***, and ***water turbine***. Other prime movers include: geothermal, solar, wind, and biomass.

Peakload: A peakload generating unit, normally the least efficient of the three unit types, is used to meet requirements during the periods of greatest, or peak, load on the system. (http://www.eia.doe.gov/cneaf/electricity/page/prim2/chapter2.html)

Power Marketers: Business entities engaged in buying, selling, and marketing electricity. Power marketers do not usually own generating or transmission facilities. Power marketers, as opposed to brokers, take ownership of the electricity and are involved in interstate trade. These entities file with the Federal Energy Regulatory Commission for status as a power marketer. (http://www.eia.doe.gov/cneaf/electricity/epav1/glossary.html)

Power Brokers: An entity that arranges the sale and purchase of electric energy, transmission, and other services between buyers and sellers, but does not take title to any of the power sold. (http://www.eia.doe.gov/cneaf/electricity/epav1/glossary.html)

Prime Movers: The engine, turbine, water wheel or similar machine that drives an electric generator. Also, for reporting purposes, a device that directly converts energy to electricity, e.g., photovoltaic, solar, and fuel cell(s).

Public Utility Regulatory Policies Act (PURPA): In 1978 PURPA opened up competition in the electricity generation market by creating a class of nonutility electricity-generating companies referred to as "qualifying facilities."

Reliability: Electric system reliability has two components: adequacy and security. Adequacy is the ability of the electric system to supply customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system facilities. (http://www.eia.doe.gov/cneaf/electricity/epav1/glossary.html)

Steam Turbine: A generating unit in which the prime mover is a steam turbine. The turbines convert thermal energy (steam or hot water) produced by generators or boilers to mechanical energy or shaft torque. This mechanical energy is used to power electric generators, including combined-cycle electric generating units, that convert the mechanical energy to electricity.

Stranded Costs: The difference between revenues under competition and costs of providing service, including the inherited fixed costs from the previous regulated market. (http://www.eia.doe.gov/cneaf/electricity/epav1/glossary.html)

Transmission: The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

Utility: A corporation, person, agency, authority, or other legal entity or instrumentality that owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public and files forms listed in the Code of Federal Regulations, Title 18, Part 141. Facilities that qualify as cogenerators or small power producers under the Public Utility Regulatory Policies Act (PURPA) are not considered electric utilities. (http://www.eia.doe.gov/emeu/iea/glossary.html)

Water Turbine: A unit in which the turbine generator is driven by falling water.

Watt: The electrical unit of power. The rate of energy transfer equivalent to 1 ampere flowing under the pressure of 1 volt at unity power factor.(Does not appear in text)

Watthour (Wh): An electrical energy unit of measure equal to 1 watt of power supplied to, or take from, an electric circuit steadily for 1 hour. (Does not appear in text)

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Chapter B1: Summary of Compliance Costs

INTRODUCTION

This chapter presents the estimated costs to facilities of complying with the Proposed Section 316(b) Phase II Existing Facilities Rule. EPA developed unit costs of complying with the various requirements of the proposed rule and the alternative regulatory options, including costs of section 316(b) technologies, energy costs, and administrative costs. Unit costs were then assigned to the 550 in-scope facilities, based on the facilities' modeled compliance responses, and aggregated to the national level.

CHAPTER CONTENTS

Chapter A1: Introduction and Overview summarizes the requirements of the proposed Phase II rule and five alternative regulatory options considered by EPA. EPA costed four of these options. This chapter discusses the unit costs for the proposed rule and the alternative regulatory options, the compliance years of Phase II facilities, and the total private industry costs of the proposed rule. Compliance years for the alternative options are presented in the appendix to this chapter; costs for the alternative options are presented in *Chapter B7: Alternative Options - Costs and Economic Impacts*.

B1-1 UNIT COSTS

Unit costs are estimated costs of certain activities or actions, expressed on a uniform basis (i.e., using the same units), that a facility may take to meet the regulatory requirements. Unit costs are developed to facilitate comparison of the costs of different actions. For this analysis, the unit basis is dollars per gallon per minute ($/gpm) of cooling water intake flow. All capital and operating and maintenance (O&M) costs were estimated in these units. These unit costs are the building blocks for developing costs at the facility and national levels.

EPA developed cost estimates for a number of alternative regulatory options, based on a variety of technologies for impingement mortality and entrainment reduction. For each regulatory option, individual facilities will incur only a subset of the unit costs, depending on the extent to which their current technologies already comply with the requirements of that regulatory option and on the compliance response they select. The unit costs presented in this section are engineering cost estimates, expressed in 2001 dollars. More detail on the development of these unit costs is provided in the *Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Rule*, hereafter referred to as the "*Phase II Technical Development Document*" (EPA, 2002a).

To characterize the existing facilities' current technologies, EPA compiled facility-level, cooling system, and intake structure data for the 225 in-scope 316(b) Detailed Questionnaire (DQ) respondents and, to the extent possible, for the 314 in-scope 316(b) Short Technical Questionnaire (STQ) respondents. The Agency then used this tabulation of data to make determinations about costing decisions that hinged on the cooling systems and intake technologies in place. Where the STQ responses did not provide sufficient information to make the necessary costing decisions, EPA applied the concept of data projection to the DQ facilities to estimate the missing data pieces for the STQ facilities, as described in the *Phase II Technical Development Document*.

B1-1.1 Technology Costs

Existing facilities that do not currently comply with the Proposed Section 316(b) Phase II Existing Facilities Rule would have to implement one or more technologies to reduce impingement mortality and entrainment. The specific technologies vary for the different alternative regulatory options considered by EPA, but overall these technologies reduce impingement and entrainment (I&E) through one of two general methods:

- implementing design and construction technologies to reduce impingement mortality and entrainment, and
- converting cooling systems from once-through to recirculating operation to reduce the design intake flow.

EPA developed distinct sets of cooling water intake structure compliance costs for existing facility model plants expected to (1) upgrade intake technologies only, (2) upgrade cooling systems and intake structure technologies, and (3) upgrade cooling systems only. The remainder of Section B1-1.1 discusses specific section 316(b) technologies and their respective costs.

a. Intake technologies

All of the regulatory options (with the exception of the dry cooling option) considered by EPA would require some existing facilities to upgrade their cooling water intake structure technologies. Upgrades to intake structure technologies at existing facilities may include retrofitting of impingement technologies, entrainment technologies, or both. In some cases, retrofitting of intake structure technologies may also necessitate modifying the intake structures themselves. For example, retrofitting an intake to entrainment-reducing fine-mesh screens (which would have reduced open cross-sectional area as compared to coarse-mesh screens) may also necessitate expanding, fanning, or adding additional bays to an existing intake structure in order to maintain the required intake flow rate.

❖ *Fine-Mesh Traveling Screen*

For those model facilities projected to install or upgrade entrainment technologies without flow reduction, EPA based the CWIS technology costs on unit costs developed for fine-mesh traveling screens. Fine-mesh screens are typically mounted on conventional traveling screens and are used to exclude eggs, larvae, and juvenile forms of fish from intakes. Fine-mesh screens generally include those with mesh sizes of 5 mm or less. A detailed explanation of the development of "greenfield" facility traveling screen unit costs can be found in the *Technical Development Document for the Final Regulations Addressing Cooling Water Intake Structures for New Facilities*. The "greenfield" capital costs for fine-mesh traveling screens were then inflated by the "retrofit" capital cost factor of 30 percent. A 10 percent contingency factor and a 5 percent allowance were also applied to account for uncertainties inherent in intake modifications at existing facilities. Therefore, the Agency views the retrofit capital costs developed for upgrading intake screens to be appropriate for existing model plants.

For those plants projected to only incur entrainment related costs of cooling water intake structure upgrades, the Agency estimated that intake fanning/expansion would be necessary for the majority of plants projected to install entrainment-reducing fine-mesh screens. Therefore, the Agency developed capital costs that incorporated the costs of expanding/fanning or adding an additional bay to an existing intake structure to provide an increase in screen area of 50 percent, in order to accommodate the fine-mesh screens. Because fine-mesh screens have reduced open cross-sectional area when compared to coarse-mesh screens, the Agency considers the intake expansion/fanning costs to be appropriate in these cases. Even though there is no set of velocity-based requirements for this proposal, the Agency projected that the model plants expected to upgrade their intake screens from coarse to fine-mesh would reduce their through-screen velocity from the median facility value of 1.5 feet/second to 1.0 foot/second as a result of this rule. The Agency used costs developed for fine-mesh screens with a through-screen velocity of 1.0 foot/second to size the intake for the full design intake flow. The O&M costs of these screens were calculated based on the same principle. The Agency applied a capital cost inflation factor of 30 percent (55 percent for nuclear facilities), in addition to the 30 percent "retrofit" factor, to account for the expansion/fanning of the intake structure, but did not estimate further O&M costs for this one-time activity.

For those plants projected to incur costs of flow reduction and entrainment-reducing fine-mesh screens, the Agency considered the existing intake structures to be of a size too large for a realistic screen retrofit. Therefore, in these cases, the Agency estimated that one-half of the intake bay(s) would be blocked/closed and the retrofitted fine-mesh intake screens would apply to only one-half of the size of the original intake. The Agency considers this a reasonable approach to estimating realistic scenarios where the average plant uses multiple intake bays. In the Agency's view, the plant, when presented an equal opportunity option, would use the potential cost-saving option of installing the fine-mesh screens on only the maximum intake area necessary. The O&M costs were also developed using this size of an intake.

❖ *Fish Handling and Return System*

For those model plants projected to install or upgrade impingement control or survival technologies, EPA based the CWIS technology costs on unit costs developed for fish handling and return systems. Conventional vertical traveling screens contain a series of wire-mesh screen panels that are mounted end to end on a band to form a vertical loop. As water flows through the panels, debris and fish that are larger than the screen openings are caught on the screen or at the base of each panel in a basket. As the screen rotates, each panel in turn reaches a top area where a high-pressure jet spray wash pushes debris and fish from the basket into a trash trough for disposal. As the screen rotates over time, the clean panels move down, back into the water to screen the intake flow.

Conventional traveling screens can be operated intermittently or continuously. However, when these screens are fitted with fish baskets (also called modified conventional traveling screens or Ristroph screens), the screens must be operated continuously so that fish that are collected in the fish baskets can be released to a bypass/return using a low pressure spray wash when the basket reaches the top of the screen. A detailed explanation of the development of "greenfield" unit costs for fish handling and return systems can be found in the *Technical Development Document for the Final Regulations Addressing Cooling Water Intake Structures for New Facilities*. The "greenfield" capital costs for fish handling and return systems were then inflated by the "retrofit" capital cost factor of 30 percent. A 10 percent contingency factor and a 5 percent allowance were also applied to account for uncertainties inherent in intake modifications at existing facilities.

For those model plants projected only to incur costs of adding fish handling/return systems to existing screens, EPA developed costs by estimating the size of coarse-mesh, 1.0 foot/second screens. The median through-screen velocity for all 316(b) survey respondents was 1.5 feet/second. The Agency thus determined that use of a 1.0 foot/sec metric to size the fish handling/return systems was a conservative assumption (that is, would most likely result in an overestimate of fish handling/return system costs) for the variety of plants projected to incur their capital and O&M costs as a result of the proposed rule.

❖ *Fine-Mesh Traveling Screens with Fish Handling and Return Systems*

For those plants projected to install or upgrade both impingement and entrainment technologies, EPA based the CWIS technology costs on unit costs for fine-mesh traveling screens with fish handling and return systems, which were developed as noted above.

For those plants projected to incur costs of both impingement and entrainment technologies, but not flow reduction, EPA developed capital costs that incorporated the costs of expanding/fanning or adding an additional bay to an existing intake structure to provide an increase in screen area of 50 percent, in order to accommodate the fine-mesh screens. The Agency used costs developed for fine-mesh screens with a through-screen velocity of 1.0 feet/second to size the intake for the full design intake flow. The O&M costs of these screens were calculated based on the same principle. Capital and O&M costs for the fish handling and return systems were also based on the size of the larger screens. The Agency applied a capital cost inflation factor of 15 percent (30 percent for nuclear facilities), in addition to the 30 percent "retrofit" factor, to account for the expansion/fanning of the intake structure, but did not estimate further O&M costs for this one-time activity.

For those plants projected to incur costs of flow reduction and both impingement and entrainment technologies, EPA estimated CWIS technology costs based on the assumption that one-half of the intake bay(s) would be blocked/closed. Therefore, the installed capital costs and O&M costs of the intake screens and fish handling/return systems were approximately one-half of those for a full-size screen replacement.

b. Wet cooling towers

Certain of the alternative regulatory options considered by EPA would require some existing facilities to reduce their flow to a level commensurate with a closed-cycle recirculating system. Facilities are not required to install wet cooling towers to reduce their flow to that level. While that level can be achieved by purchasing water from another source or using gray water, EPA has assumed for costing purposes that the facility would recycle their water. Switching an existing facility to a recirculating system involves retrofitting the facility to convert the cooling system from once-through to recirculating operation. Cooling towers are by far the most common type of recirculating system; however, if enough land is available, cooling ponds offer another, and potentially less expensive, approach. For the regulatory options that involved switching to recirculating systems, EPA therefore assumed that all facilities switching to recirculating systems would use cooling towers.

The methodology for estimating costs of these cooling system conversions is based on a set of common principles:

- recirculating systems can be connected to the existing condensers and operated successfully under certain (but not all) conditions,
- condenser flows generally do not change due to the conversions,

- portions of the existing condenser conduit systems can be used for the recirculating tower systems,
- the existing intake structures can be used for supplying make-up water to the recirculating towers,
- tower structures can be constructed on-site before connection to the existing conduit system, and
- modification and branching is generally necessary for connecting the recirculating system to the existing conduits and for providing make-up water to the towers.

❖ *Wet Tower Costs*

Based on the principles outlined above, EPA developed capital cost estimates for cooling system conversions using those developed for new "greenfield" facilities under the 316(b) Phase I Rule for New Facilities. For most model facilities that were projected to install cooling towers, EPA based the cooling tower capital costs on unit costs developed for redwood mechanical draft cooling towers with splash fill, which represents a median tower cost. However, EPA determined that redwood tower unit costs were not appropriate for nuclear facilities. EPA thus based cooling tower capital costs for nuclear facilities on unit costs developed for concrete mechanical draft cooling towers. A detailed explanation of the development of "greenfield" facility cooling tower unit costs can be found in the *Technical Development Document for the Final Regulations Addressing Cooling Water Intake Structures for New Facilities.*

EPA then inflated these capital cost estimates by applying a "retrofit" factor to account for activities outside the scope of the "greenfield" cost estimates. These activities relate to the "retrofit," or upgrade, of existing cooling water systems. Retrofit activities associated with installation of recirculating wet cooling systems may include (but are not necessarily limited to) branching or diversion of cooling water delivery systems, reinforcement of retrofitted conduit system connections, partial or full demolition of conduit systems and/or structures, additional excavation activities, expedited construction schedules, and administrative and construction-related safety precautions. The Agency estimated that a capital cost inflation factor of 20 percent applied to the costs developed for new "greenfield" projects would account for the cooling system retrofit activities described above.

In addition to the 20 percent "retrofit" factor, EPA also used a 10 percent contingency factor for existing facilities. To account for variations in capital construction costs for different locations within the United States, EPA adjusted the capital cost estimates for the existing facilities using state-specific cost factors, which ranged from 0.739 for South Carolina to 1.245 for Alaska. The applicable state cost factors were multiplied by the model-facility cost estimates to obtain location-specific model facility capital costs. The Agency derived the state-specific capital cost factors from the "location cost factor database" in R.S. Means Cost Works 2001 (R.S. Means, 2001). The Agency used the weighted-average factor category for total costs (including material and installation). The RS Means database provides cost factors (by 3-digit Zip code) for numerous locations within each state. The Agency selected the median of the cost factors for all locations reported within each state as the state-specific capital cost factor. Additional detail on the development of the retrofit, contingency, and state-specific cost factors used by EPA can be found in the *Phase II Technical Development Document*.

EPA estimated that O&M costs of wet cooling tower systems for conversion projects would be the same as those developed for new "greenfield" facilities during the 316(b) Phase I Rule for New Facilities. Detail on O&M costs of wet cooling tower systems can be found in the *Technical Development Document for the Final Regulations Addressing Cooling Water Intake Structures for New Facilities*. The Agency notes that recirculating pumping costs included in these O&M costs will roughly equal those of the baseline once-through system, which the Agency deducts from annual costs of cooling system conversion projects. In the end, the O&M costs of cooling tower pumping will roughly cancel between those included within the cooling tower recurring annual costs and those deducted as recurring annual costs of an abandoned system. In EPA's view, this methodology presents a realistic estimate of the actual O&M costs of cooling tower conversion projects.

❖ *Intake Piping Modification Costs*

Conversions from once-through to recirculating cooling systems do not necessarily require construction of new intake structures to provide make-up water to the cooling tower systems. Installation of a fully recirculating cooling system reduces intake flow by upwards of approximately 92 percent as compared to a once-through system. The intake structure designed for a once-through cooling system is oversized for moving flows reduced to this level. Based on example cases, EPA anticipates that most existing facilities will be able to continue to use their baseline intake structures and portions of the associated intake piping systems after converting to recirculating cooling systems. A branch from the original intake conduit system would be needed to provide make-up flow to the cooling tower via a separate pump system. Thus, for purposes of capital cost development, EPA excluded the itemized costs of make-up water pumps in favor of the larger recirculating cooling water pumps inherent in the Agency's cooling tower cost estimates. However, the Agency included capital costs for the conduit system required to bring make-up water to the cooling tower and basin and to discharge blowdown. The Agency estimated that a range of 2000 feet to 4000 feet (depending on intake flow) of concrete-lined steel piping would be used for cooling tower make-up water and blowdown.

The Agency included these costs to account for conversion cases in which significant distances may exist between intake locations and cooling tower sites. While this was not necessarily true for the example cases reviewed by EPA, the Agency views these costs as appropriate for a variety of hypothetical cases. For instance, the Agency is aware of concerns from some existing facilities regarding the need to maintain a reasonably high velocity within the intake structure conduit system to minimize deposition and/or biological growth. By including the make-up water piping capital costs, the Agency's estimates address these concerns by accounting for construction of relatively small-sized intake piping within existing large-sized, once-through intake conduits, closure of a portion of intake bays and/or conduits to maintain in-conduit velocity, and/or branching from the existing intake conduit systems.

As with the wet cooling tower cost estimates, these piping capital costs were further inflated by a "retrofit" factor. The Agency uses a factor of 30 percent to account for construction techniques and situations outside the scope of a typical "greenfield" cost estimate. In addition, EPA applied a 10 percent contingency factor and a 5 percent allowance to account for uncertainties inherent in intake modifications at existing facilities.

❖ ***Intake Pumping Costs***

The Agency did not include the costs of installing pumps for supplying make-up water to the cooling towers. The Agency developed costs for variable-speed pumps for make-up water intakes in its cost development for new facilities, but excluded them from the costs of cooling system conversions. The Agency estimated, based on a set of example cases, that existing intake structures could be reused for the recirculating cooling systems and that a portion of the existing pumping system would be reused.

The Agency used estimates of O&M costs of once-through cooling based on a methodology similar to that used to develop costs for the 316(b) Phase I Rule for New Facilities.

It should be noted that the O&M costs associated with a wet cooling tower do not include consideration of the effects on turbine efficiency resulting from the differences in turbine exhaust pressure caused by changes in the cooling system (see discussion in Section B1-1.2 below).

c. Condensers

For the regulatory options that include wet cooling towers, EPA included costs for premature condenser refurbishments for a portion of the model plants projected to incur costs of cooling tower conversions. The Agency projected premature condenser refurbishments, in part, to alleviate potential condenser tube failures related to cooling tower conversions, such as that experienced at one of the example case facilities. EPA consulted with condenser manufacturing representatives for advice on probable causes for condenser failures due to cooling system conversions, motivations for condenser replacements or refurbishments, useful lives of condensers, and appropriate tube materials for recirculating cooling systems for a variety of water types. The Agency learned from condenser vendors that plants would likely elect to upgrade condenser tube materials to increase the efficiency of the recirculating cooling system. In addition, for plants using brackish or saline cooling water, the Agency judged that the material of the tubes would need to withstand corrosive effects of chemical addition and increased salt content of the cooling water (due to concentration in a recirculating system). Hence, the Agency developed a baseline standard of condenser tube material and based on that determined which model plants would most likely upgrade condenser tube materials.

EPA judged that the minimum standard material would be copper-nickel alloy (of any mixture) for brackish water (i.e., for facilities with intakes withdrawing water from estuaries/tidal rivers) and stainless steel (of any type) for saline water (i.e., for facilities with intakes withdrawing water from oceans). The Agency then consulted the 1994 UDI database to determine the condenser tube material for the existing plants projected to incur cooling tower conversion costs. For the units at each plant with condenser tube materials judged to be of a quality below that of the minimum standards, the Agency estimated that the plant would refurbish the condenser (thereby upgrading the condenser tubes) as a result of the cooling system conversion. The Agency projected that tube material for the upgrades would be stainless steel for all model plants receiving upgrade refurbishments. At some plants, EPA projected that only a portion of the site's condensers would require refurbishment.

EPA contacted condenser vendors to obtain cost estimates for refurbishing existing condensers and for full condenser replacements. Using the vendor information, EPA developed unit cost estimates (on a flow basis) for several types of condenser tube materials – copper-nickel alloy, stainless steel, and titanium – as detailed in the *Phase II Technical Development Document*. The capital cost estimates for condenser refurbishing were lower than those for full replacements, and the Agency determined that, given equal opportunity, facilities would make the economic decision to refurbish existing condensers rather than replace the shell and the tubes. The condenser refurbishing costs developed by the Agency account for the tube materials, full labor, overhead, and potential bracing of the shell due to buoyancy changes (related to differences in replacement tube material and, hence, densities).

Power plants will refurbish or replace condensers on a periodic basis. Condenser vendors estimated the average useful life of condenser tubes as 20 years. In order to determine remaining useful life of the condensers at the model plants, the Agency calculated a condenser replacement/refurbishing schedule based on the 20-year useful life estimate and the age of the generating units at the plants. The average useful life remaining for a condenser at the model plants was approximately 9.5 years (in 2001). The Agency rounded this to 10 years and used this figure to represent lost operating years as a result of premature condenser refurbishments. EPA estimated that the baseline condenser material for any plant upgrading a condenser would be copper-nickel alloy. Therefore, plants upgrading condensers in order to install recirculating cooling would incur the costs of the full condenser refurbishment/upgrade to stainless steel. However, 10 years later, they would save the costs of replacing the original condenser, with a new condenser made of the same, lesser material (e.g., copper-nickel alloy). Both the cost of condenser replacement and the savings associated with not having to replace the original condenser 10 years later, are accounted for in EPA's cost analysis.

d. Dry cooling

One of the alternative regulatory options considered by EPA would require some existing facilities to switch to dry cooling (air cooled condensers). EPA developed capital cost estimates for dry cooling system conversions using those developed for new "greenfield" facilities under the 316(b) Phase I Rule for New Facilities. A detailed explanation of the development of "greenfield" facility dry cooling unit costs can be found in the *Technical Development Document for the Final Regulations Addressing Cooling Water Intake Structures for New Facilities.*

The capital cost equations were based on equivalent cooling water flow rates (gpm), using the once-through design intake cooling flow as the independent variable. EPA inflated the "greenfield" capital cost estimates by applying a "retrofit" factor of 5 percent, a contingency factor of 10 percent, and a 5 percent allowance to account for activities outside the scope of the "greenfield" cost estimates. Intake pumping was assumed to decrease to zero or near zero. Therefore, no costs were included for intake or piping modifications. In addition, it should be noted that the dry cooling capital costs do not include any consideration for replacement or modification of the steam turbines. The Agency developed dry cooling costs for new "greenfield" facilities based on the installation of direct dry cooling systems. Since direct dry cooling systems would require existing facilities to replace their steam-turbines, EPA assumed that indirect dry cooling systems would be used instead. Therefore, the Agency has developed facility-level dry cooling costs for indirect systems by using data from direct dry cooling systems.

EPA revised the O&M costs for dry cooling using a different basis than was used for the New Facility Rule compliance cost estimates. Rather than base the technology costs on factors applied to the capital costs as previously done, EPA based the O&M unit costs on energy requirements and cost information obtained from facility personnel and vendors. A detailed explanation of the development of the dry cooling O&M costs can be found in the *Phase II Technical Development Document*. It should be noted that these dry cooling O&M costs do not consider the effects on turbine efficiency resulting from the differences in turbine exhaust pressure caused by changes in the cooling system (see discussion in Section B1-1.2 below). As noted above, the Agency estimates that if dry cooling were used at existing facilities, the indirect dry cooling system would be employed. The Agency developed the size and energy requirements of its new "greenfield" dry cooling systems based on the more efficient (and, therefore, smaller) direct dry cooling systems.

B1-1.2 Energy Costs

Converting a cooling system from a once-through system to a recirculating system with a wet cooling tower or to a dry cooling system could affect a plant's operation in two ways. The first potential effect is an "energy penalty" from the operation of the recirculating or dry cooling system. Energy penalty estimates reflect the long-term reduction in available capacity due to the ongoing operation of the new system. The second potential effect is a one-time, temporary outage of the plant when the new system is connected to the plant's existing cooling system. Both effects are discussed in the subsections below. The third subsection discusses EPA's monetary valuation of the energy penalty and the cost of downtime.

a. Energy penalty

The energy penalty is the long-term reduction in available capacity as a result of operating a recirculating or dry cooling system and is expressed as a percent of generating capacity. The energy penalty consists of two components: (1) a reduction in unit efficiency due to increased turbine back-pressure and (2) an increase in auxiliary power requirements to operate the new system (e.g., for pumping and fanning). EPA estimated energy penalties for different types of generators (nuclear, combined-cycle, and fossil fuel) and different geographic regions (northeast, south, mid-west, and U.S. average). The

estimated mean annual energy penalty for a recirculating system with wet cooling towers is 1.70 percent for nuclear units, 1.65 percent for fossil fuel units (including coal, oil, and natural gas), and 0.40 percent for combined-cycle units. The estimated mean annual energy penalty for a dry cooling system is 8.53 percent for nuclear units, 8.58 percent for fossil fuel units (including coal, oil, and natural gas), and 2.09 percent for combined-cycle units. EPA also considered the energy requirements of other compliance technologies, such as rotating screens, but found them insignificant and thus excluded them from this analysis.

As described in Section B1-1 above, EPA's estimates of O&M costs already include the second portion of the energy penalty, the increase in auxiliary power requirements. Therefore, to avoid double-counting these costs, only the turbine back-pressure part of the energy penalty was applied to the national cost estimate.

Table B1-1 below presents EPA's estimate of the energy penalty for wet cooling towers and dry cooling systems by facility type and geographic region.

Table B1-1: Annual Energy Penalty (% of Plant Capacity) by Facility Type and Geographic Region

Region	Nuclear			Fossil Fuel			Combined-Cycle		
	Turbine	Aux. Power	Total	Turbine	Aux. Power	Total	Turbine	Aux. Power	Total
Recirculating Systems with Wet Cooling Towers									
Northeast (MA)	0.73%	0.85%	**1.58%**	0.88%	0.77%	**1.65%**	0.14%	0.26%	**0.39%**
South (FL)	1.03%	0.85%	**1.88%**	0.93%	0.77%	**1.69%**	0.18%	0.26%	**0.44%**
Midwest (IL)	0.96%	0.85%	**1.82%**	1.00%	0.77%	**1.77%**	0.16%	0.26%	**0.41%**
West (WA)	0.67%	0.85%	**1.52%**	0.74%	0.77%	**1.51%**	0.11%	0.26%	**0.37%**
U.S. Average	**0.85%**	**0.85%**	**1.70%**	**0.89%**	**0.77%**	**1.65%**	**0.15%**	**0.26%**	**0.40%**
Dry Cooling Systems									
Northeast (MA)	4.96%	2.40%	**7.36%**	4.69%	2.45%	**7.14%**	0.98%	0.82%	**1.80%**
South (FL)	9.63%	2.40%	**12.0%**	10.06%	2.45%	**12.5%**	2.14%	0.82%	**2.96%**
Midwest (IL)	5.35%	2.40%	**7.75%**	5.26%	2.45%	**7.71%**	1.06%	0.82%	**1.88%**
West (WA)	4.60%	2.40%	**7.00%**	4.50%	2.45%	**6.95%**	0.90%	0.82%	**1.72%**
U.S. Average	**6.13%**	**2.40%**	**8.53%**	**6.13%**	**2.45%**	**8.58%**	**1.27%**	**0.82%**	**2.09%**

Source: Phase II Technical Development Document (U.S. EPA, 2002a).

b. Connection outage

The second energy effect associated with the conversion to a recirculating or a dry cooling system is a one-time, temporary outage of the plant when the new system is connected to the plant's existing cooling system. EPA estimates that the average construction and installation outage would be one month. This is the net outage attributable to the installation. EPA assumes that plants would minimize the disruption to their operations by installing the new system during times of scheduled maintenance outages. Scheduled maintenance outages can range from several weeks to several months, depending on the type of facility and the specific maintenance requirements.[1] Therefore, by scheduling the connection of the new system during maintenance periods, facilities could minimize the net impact to approximately one month but have several months to complete the connection.

c. Monetary valuation of energy cost

The energy penalty and the connection outage represent a cost to the facilities that incur them. For the energy penalty, this cost manifests itself as a reduction in revenues (the same amount of fuel is required to produce less electricity available for sale). For the connection outage, this cost is a loss in revenues offset by a simultaneous reduction in fuel costs (while the plant is out of service, it loses revenues but also does not incur variable costs of production).

EPA calculated facility-level baseline revenues using estimates of facility-specific average annual electricity sales and wholesale electricity prices:

- ***Facility Average Annual Electricity Sales (MWh):*** EPA calculated electricity sales for a "typical" operating year for each in-scope facility. This estimate is based on net generation data for each facility, adjusted to reflect that not all net generation will be sold for revenue. EPA calculated the average annual net generation for each in-scope facility over the five-year period 1995 to 1999 and excluded from this average "outlier" years, i.e., years of unusually low levels of generation. This analysis defines outlier years as net generation of 70 percent or more below the facility's average 1995 to 1999 net generation.[2] To derive electricity sales for a "typical" operating year, EPA adjusted the average net generation estimate to account for generation that is (1) lost due to transmission or distribution inefficiencies, (2) furnished without charge, or (3) used by the utility's own electricity department. The electricity sales adjustment is based on the average (1995 to 1999) percent of utility-level energy disposition that is sold. This percentage was calculated for each facility's owner.[3] For facilities without available utility-level energy disposition information, EPA used the 1995 to 1999 average for all in-scope facilities for which this information was available (95 percent of total energy sold, based on 531 facilities).

- ***Wholesale Electricity Price:*** EPA used utility-level revenues and electricity sales from Form EIA-861 to calculate the utility-specific wholesale price of electricity. EPA calculated each utility's average wholesale price of electricity by dividing revenues from *sales for resale* by the quantity of *sales for resale*.[4] EPA used revenue from sales for resale instead of average revenue per unit sale by the total company for this calculation since sales for resale represents the value of electricity at the generator busbar and does not include the price of additional value-added services provided by the company as it delivers generated electricity to its customers. Thus, the average price received for sales for resale is approximately a wholesale electricity price as received by the company. EPA estimated this price for each year between 1995 and 1999 and adjusted the values to constant year-2001 dollars using the electric power producer price index (PPI).

EPA estimated ***fuel cost per MWh of generation*** for each facility costed with a cooling tower under one of the regulatory options considered based on annual data forms for utility-owned power plants (FERC Form 1 for investor-owned utilities, Form EIA-412 for public electric utilities, and Form RUS 12 for rural electric cooperatives) compiled in OPRI's DataPik Electric Generating Plant Database (as of February 2000 and May 2001).

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[1] For a detailed discussion of scheduled maintenance outages, see the *Phase II Technical Development Document*.

[2] Annual net generation is based on the U.S. Department of Energy's (U.S. DOE) Form EIA-906 (formerly known as Forms EIA-759 and EIA-900). When data were not available from EIA Form-906, EPA used a compilation of annual data forms for utility-owned power plants (FERC Form 1 for investor-owned utilities, Form EIA-412 for public electric utilities, and Form RUS 12 for rural electric cooperatives; compiled in OPRI's DataPik Electric Generating Plant Database, as of February 2000 and May 2001).

[3] EPA used utility-level energy disposition information from the U.S. DOE's Form EIA-861.

[4] When the wholesale price could not be calculated, EPA calculated a price based on all utility-level revenues and electricity sales (including both electricity sales to ultimate consumers and electricity sales for resale).

❖ ***Energy Penalty***

To estimate the monetary value of the energy penalty, EPA calculated the loss in electricity sales by multiplying the facility's average annual electricity sales by the energy penalty percentages in Table B1-1 above. The penalty estimate used in this calculation is the turbine part of the penalty and is based on each facility's type and geographic region. EPA multiplied the loss in electricity sales by each facility's electricity price estimate to calculate the annual revenue loss from the energy penalty.

The following formulas were used to calculate this revenue loss:

$$\textit{Annual Revenue Loss} = \textit{Annual Loss of Electricity Sales} \times \textit{Electricity Price}$$

where:

$$\textit{Annual Loss of Electricity Sales} = \textit{Annual Electricity Sales} \times \textit{Energy Penalty}$$

❖ ***Connection outage***

The average cost of the connection outage is the revenue loss during the downtime less the fuel expenses that would normally be incurred during that period. EPA calculated the revenue loss due to the connection outage by dividing the facility's average annual sales by twelve and multiplying this value by the facility's electricity price estimate. EPA calculated the fuel cost by dividing the facility's average annual net generation by twelve and multiplying this value by each facility's fuel cost per MWh of generation.

The following formulas were used to calculate the net loss due to downtime:

$$\textit{Cost of Connection Outage} = \textit{Revenue Loss} - \textit{Fuel Costs}$$

where:

$$\textit{Revenue Loss} = \frac{\textit{Average Annual Electricity Sales}}{12} \times \textit{Electricity Price}$$

and

$$\textit{Fuel Costs} = \frac{\textit{Average Annual Net Generation}}{12} \times \textit{Fuel Cost per MWh of Generation}$$

This approach may overstate the cost of the connection outage because it uses average electricity sales and prices. If downtime is scheduled during off-peak times, both the loss in electricity sales and the price per MWh could be lower. In addition, variable production costs other than fuel costs may be avoided during downtime. By only including fuel costs, EPA again may have overestimated the cost of the connection outage.

B1-1.3 Administrative Costs

Compliance with the proposed Phase II rule would require facilities to carry out certain administrative functions. These are either one-time requirements (compilation of information for the initial post-promulgation NPDES permit) or recurring requirements (compilation of information for subsequent NPDES permit renewals; and monitoring, record keeping, and reporting). This section describes each of these administrative requirements and their estimated costs.

a. Initial post-promulgation NPDES permit application

The proposed rule would require existing facilities to submit information regarding the location, construction, design, and capacity of their existing or proposed cooling water intake structures, technologies, and operational measures as part of their initial post-promulgation NPDES permit applications. Some of these activities would be required regardless under the current case-by-case cooling water intake structure permitting procedures, so to some extent the permitting costs of this proposed rule are over-costed. Ideally, these costs would be estimated on only an incremental basis. Activities and costs associated with the initial permit renewal application include:

- ***start-up activities:*** reading and understanding the rule; mobilizing and planning; and training staff;

- ***permit application activities:*** developing drawings that show the physical characteristics of the source water; developing a description of the CWIS configuration; developing a facility water balance diagram; developing a narrative of operational characteristics; developing a description of the existing cooling water system; submitting materials for review by the Director; and keeping records;
- ***source water baseline biological characterization data:*** identifying available data and documenting efforts; compiling and analyzing existing data; submitting materials for review by the Director; and keeping records;
- ***proposal for collection of information for comprehensive demonstration study:*** developing a proposal for the collection of information; developing a description of the proposed and/or implemented technologies, operational measures, and restoration measures to be evaluated; developing a description of historical studies that will be used; developing a summary of public participation and consultation with fish and wildlife agencies; developing a sampling plan; submitting data and plans for review; revising plans based on state review; and keeping records;
- ***source waterbody flow information****:* determining the annual mean flow of the waterbody for freshwater rivers/streams; developing a description of the thermal stratification of the waterbody for lakes/reservoirs; preparing supporting documentation and engineering calculations; submitting data for review; and keeping records;
- ***impingement mortality and entrainment characterization study:*** performing biological sampling; developing a taxonomic identification and characterization of species of fish and shellfish and their life stages; documenting impingement mortality and entrainment of all life stages of fish and shellfish; identifying protected species; submitting the study for review; and keeping records;
- ***impingement mortality and entrainment characterization study capital and O&M costs:*** contract laboratory analysis of samples;
- ***design and construction technology plan:*** calculating facility capacity utilization rate; describing in-place or selected technologies and operational measures; documenting efficacy of the technologies; performing design calculations and preparing drawings and estimates; submitting the plan for review; and keeping records;
- ***evaluation of potential cooling water intake structure effects:*** calculating the baseline upon which to assess total reduction in impingement mortality and entrainment; calculating reduction in impingement mortality and entrainment that would be achieved by the technologies and operational measures selected; demonstrating that the location, design, construction and capacity of the intake reflects the best technology available (BTA) for minimizing adverse environmental impact; performing impingement and entrainment pilot studies; submitting data and analysis for review; and keeping records;
- ***impingement and entrainment pilot study capital and O&M costs:*** purchasing, installing and operating pilot study technology; laboratory analysis of samples;
- ***information to support site-specific determination of best technology available (BTA) for minimizing adverse environmental impact:*** performing a comprehensive cost evaluation study; developing a monetized valuation of the benefits of reducing impingement and entrainment; performing engineering calculations and drawings; submitting results for review; and keeping records;
- ***site-specific technology plan:*** describing selected technologies, operational measures and restoration measures; documenting efficacy of the proposed and/or implemented technologies or operational measures; developing site-specific evaluation of suitability of technologies or operational measures; performing design calculations and preparing drawings and estimates; submitting the plan for review; and keeping records;
- ***verification monitoring plan:*** developing a narrative description of the frequency of monitoring, parameters to be monitored, and the basis for determining the parameters and frequency and duration of monitoring; and keeping records;
- ***remote monitoring device capital and O&M costs:*** installation of remote monitoring devices.

Table B1-2 below lists the estimated maximum costs of each of the initial post-promulgation NPDES permit application activities described above. The specific activities that a facility will have to undertake depend on the facility's source water body type, whether it exceeds capacity utilization rate and proportional flow thresholds, and whether it chooses to meet the proposed rule's performance standards or to make a site-specific determination of BTA. Certain activities are expected to be more costly for marine facilities than for freshwater facilities. Some activities will apply to all facilities, while other activities will apply only if the facility exceeds the capacity utilization rate or proportional flow thresholds or chooses to make a site-specific determination of BTA. The maximum cost a facility that implements all the activities would incur for its initial post-promulgation NPDES permit application is estimated to be approximately $1.4 million.

Table B1-2: Cost of Initial Post-Promulgation NPDES Permit Application Activities ($2001)

Activity	Estimated Maximum Cost per Permit				
	Freshwater River/ Stream	Lake	Great Lake	Estuary/ Tidal River	Ocean
Start-up activities	$2,014	$2,014	$2,014	$2,014	$2,014
Permit application activities[a]	$9,571	$9,571	$9,571	$9,571	$9,571
Source water baseline biological characterization data[a]	$11,372	$11,372	$11,372	$11,372	$11,372
Proposal for collection of information for comprehensive demonstration study	$12,407	$12,407	$12,407	$12,407	$12,407
Source waterbody flow information[a]	$3,370	$3,894	$0	$0	$0
Impingement mortality and entrainment characterization study[b]	$243,483	$243,483	$302,061	$302,061	$302,061
Impingement mortality and entrainment characterization capital and O&M costs[b]	$118,500	$118,500	$118,500	$199,230	$199,230
Design and construction technology plan[a]	$5,310	$3,807	$5,310	$5,310	$5,310
Evaluation of potential cooling water intake structure effects[a]	$122,246	$76,893	$145,338	$145,338	$145,338
Impingement and entrainment pilot study capital and O&M costs[a]	$321,600	$280,000	$280,000	$350,210	$350,210
Information to support site-specific determination of BTA[a]	$32,823	$32,823	$32,823	$32,823	$32,823
Site-specific technology plan[a]	$7,038	$7,038	$7,038	$7,038	$7,038
Verification monitoring plan[a]	$6,489	$6,489	$6,489	$6,489	$6,489
Remote monitoring device capital and O&M costs[a]	$280,000	$280,000	$280,000	$280,000	$280,000
Total Initial Post-Promulgation NPDES Permit Application Cost	**$1,176,223**	**$1,088,291**	**$1,212,923**	**$1,363,863**	**$1,363,863**

[a] The costs for these activities are incurred in the year prior to the permit application.
[b] The costs for these activities are incurred in the three years prior to the permit application.

Source: U.S. EPA, 2002b.

b. Subsequent NPDES permit renewals

Each existing facility will have to apply for NPDES permit renewal every five years. Subsequent permit renewal applications will require collecting and submitting the same type of information as required for the initial permit renewal application. EPA expects that facilities can use some of the information from the initial permit renewal. Building upon existing information is expected to require less effort than developing the data the first time especially in situations where conditions have not changed.

Table B1-3 lists the maximum estimated costs of each of the NPDES repermit application activities. The specific activities that a facility will have to undertake depend on the facility's source water body type, whether it exceeds the capacity utilization rate and proportional flow thresholds, and whether it chooses to meet the proposed rule's performance standards or to make a site-specific determination of BTA. Certain activities are expected to be more costly for facilities located on a

Great Lake, estuary, tidal river, or ocean than for freshwater facilities. The maximum cost a facility that implements all the activities would incur for its NPDES repermit application is estimated to be $53,000.

Table B1-3: Cost of NPDES Repermit Application Activities ($2001)

Activity	Estimated Maximum Cost per Permit				
	Freshwater River/ Stream	Lake	Great Lake	Estuary/ Tidal River	Ocean
Start-up activities[a]	$542	$542	$542	$542	$542
Permit application activities[a]	$6,265	$6,265	$6,265	$6,265	$6,265
Source water baseline biological characterization data[a]	$4,076	$4,076	$4,076	$4,076	$4,076
Proposal for collection of information for comprehensive demonstration study[a]	$4,579	$4,579	$4,579	$4,579	$4,579
Source waterbody flow information[a]	$1,981	$2,138	$0	$0	$0
Impingement mortality and entrainment characterization study[a]	$14,733	$14,733	$15,023	$15,023	$15,023
Design and construction technology plan[a]	$2,797	$2,011	$2,797	$2,797	$2,797
Evaluation of potential CWIS effects[a]	$7,138	$7,138	$7,138	$7,138	$7,138
Information to support site-specific determination of BTA[a]	$8,011	$8,011	$8,011	$8,011	$8,011
Site-specific technology plan[a]	$2,623	$2,623	$2,623	$2,623	$2,623
Total NPDES Repermit Application Cost	**$52,745**	**$52,116**	**$51,054**	**$51,054**	**$51,054**

[a] The costs for these activities are incurred in the year prior to the application for a permit renewal.

Source: U.S. EPA, 2002b.

c. Monitoring, record keeping, and reporting

All existing facilities subject to the proposed rule will be required to monitor to show compliance with the requirements set forth in the proposed rule. Facilities must keep records of their monitoring activities and report the results in a yearly status report. Monitoring, record keeping, and reporting activities and costs include:

- ***impingement sampling:*** collecting monthly samples for at least two years after the initial permit issuance; enumerating organisms; and keeping records;
- ***entrainment sampling:*** collecting biweekly samples during the primary period of reproduction, larval recruitment, and peak abundance for at least two years after the initial permit issuance; enumerating organisms; and keeping records;
- ***entrainment sampling capital and O&M costs:*** contract laboratory analysis of entrainment samples;
- ***visual or remote inspections:*** conducting weekly visual inspections or employing remote monitoring devices to ensure that design and construction technologies continue to function as designed; and keeping records;
- ***verification study:*** conducting technology performance monitoring; submitting monitoring results and study analysis; and keeping records;
- ***yearly status report activities:*** detailing biological monitoring results; reporting on visual or remote inspection; compiling and submitting the report; and keeping records.

Table B1-4 lists the estimated costs of each of the monitoring, record keeping, and reporting activities described above. Certain activities are expected to be more costly for marine facilities than for freshwater facilities. The maximum cost a facility will incur for its monitoring, record keeping, and reporting activities is estimated to be $110,000.

Table B1-4: Cost of Annual Monitoring, Record Keeping, and Reporting Activities ($2001)

Activity	Estimated Cost				
	Freshwater River/ Stream	Lake	Great Lake	Estuary/ Tidal River	Ocean
Impingement sampling	$16,985	$16,985	$21,623	$21,623	$21,623
Entrainment sampling	$37,369	$37,369	$46,044	$46,044	$46,044
Entrainment sampling capital and O&M costs	$8,300	$8,300	$10,640	$10,640	$10,640
Visual or remote inspections	$9,094	$9,094	$9,094	$9,094	$9,094
Remote monitoring capital and O&M costs	$250	$250	$250	$250	$250
Verification study	$6,427	$6,427	$6,427	$6,427	$6,427
Yearly status report activities	$15,656	$15,656	$15,656	$15,656	$15,656
Total Monitoring, Record Keeping, and Reporting Cost	**$94,081**	**$94,081**	**$109,734**	**$109,734**	**$109,734**

Source: U.S. EPA, 2002b.

B1-2 Assigning Compliance Years to Facilities

This section discusses the methodology used to estimate the compliance years of facilities subject to Phase II regulations. The estimated compliance years of facilities are important for two reasons: (1) they determine by how much compliance costs are discounted in the national cost estimate and (2) for options that include cooling tower requirements, a high concentration of facilities estimated to be out of service for cooling tower connection in the same region and at the same time could lead to temporary energy effects in that region.

Facilities not costed with a cooling tower have to come into compliance with the proposed Phase II rule during the year their first post-promulgation NPDES permit is issued. Since NPDES permits are renewed every five years, all facilities not costed with cooling towers will come into compliance between 2004 and 2008. Table B1-5 below presents the distribution of Phase II facilities by North American Electric Reliability Council (NERC) region and compliance year. The NERC regions presented in the table are:

- ASCC – Alaska
- ECAR – East Central Area Reliability Coordination Agreement
- ERCOT – Electric Reliability Council of Texas
- FRCC – Florida Reliability Coordinating Council
- HI – Hawaii
- MAAC – Mid-Atlantic Area Council
- MAIN – Mid-America Interconnect Network
- MAPP – Mid-Continent Area Power Pool
- NPCC – Northeast Power Coordinating Council
- SERC – Southeastern Electric Reliability Council
- SPP - Southwest Power Pool
- WSCC – Western Systems Coordinating Council

Table B1-5: Weighted Number of Phase II Facilities by NERC Region and Compliance Year

Compliance Year	NERC Region												
	ASCC	ECAR	ERCOT	FRCC	HI	MAAC	MAIN	MAPP	NPCC	SERC	SPP	WSCC	Total
2004	0	14	18	8	3	6	10	6	10	13	5	5	**99**
2005	1	20	4	10	0	11	16	6	11	20	10	16	**125**
2006	0	30	8	2	0	16	13	16	18	21	3	7	**133**
2007	0	21	7	3	0	6	5	6	12	28	5	2	**94**
2008	0	15	15	7	0	5	7	10	12	13	9	4	**97**
Total	**1**	**100**	**52**	**30**	**3**	**44**	**51**	**44**	**62**	**95**	**32**	**34**	**550**

Source: U.S. EPA analysis, 2002.

The appendix to this chapter presents EPA's methodology for assigning compliance years to facilities costed with cooling towers, and the compliance year assignment for regulatory options that include cooling tower requirements for some or all facilities.

B1-3 Total Private Compliance Costs

EPA estimated the total private pre-tax compliance costs for the proposed Phase II rule and the alternative regulatory options based on the unit costs discussed in Section B1-1 and the compliance years discussed in Section B1-2. Technology compliance costs were developed in 1999 dollars and converted to year-2001 dollars using the construction cost index (CCI). Administrative costs were developed in 2001 dollars.

B1-3.1 Methodology

The private cost of the Phase II rule represents the total compliance costs of the 550 in-scope section 316(b) Phase II facilities. Under the proposed rule, facilities are expected to comply over a five-year period between 2004 and 2008; under policy options that include a cooling tower requirement, the compliance period is between 2004 and 2012. EPA estimated the total private cost of the rule by calculating the present value of each facility's one-time costs as of 2004. To derive the constant annual value of the one-time costs, EPA annualized the costs of each compliance technology over its expected useful life, using a seven percent discount rate. EPA then added the annualized one-time costs to the annual costs to derive each facility's total annual cost of complying with the Phase II rule. EPA estimated the post-tax value of private compliance costs by applying state-specific corporate income tax rates to privately-owned facilities (government-owned entities and cooperatives are not subject to income taxes).

a. Present value of compliance costs

EPA calculated the present value of the one-time capital, downtime, and initial permit costs using a seven percent discount rate. The following assumptions were made regarding the timing of these one-time costs:

- ***Cooling Tower Capital Costs:*** This cost is incurred over a two-year period. EPA assumed that in the first year, engineering work would be completed and in the second year, the facility would install the cooling tower. The first year of this cost is the year before the facility installs a cooling tower.

- ***Other Capital Costs:*** For facilities that do not require cooling towers, this cost is incurred in the year that the facility's first post-promulgation permit is issued. For facilities requiring cooling towers, this cost is incurred in the year that the facility installs the cooling tower.

- ***Condenser Improved Material Costs:*** This cost is incurred by facilities that require cooling towers to comply with the regulation. This cost is incurred in the year that the facility installs a cooling tower.

- ***Condenser Existing Material Costs:*** This is a cost that would have been incurred by the facility ten years after installing their cooling tower if the facility had not upgraded to an improved condenser material.

- ***Cost of Connection Outage:*** EPA estimates that the average outage to construct and install a cooling tower would be one month. A more detailed description of this cost is presented in Section B1-1.2 above. This cost is incurred in the year that the facility installs the cooling tower.

- ***Baseline Characterization Study:*** This is a three-year study required for facilities with a cooling tower requirement under the waterbody/capacity-based option that decide to take Track II. The cost of this study is incurred over three years. The first year of costs is in the year that the facility's first post-promulgation permit is issued.

The following formula was used to calculate the net present value of the one-time costs as of 2004:[5]

$$Present\ Value_x = \frac{Cost_{x,t}}{(1 + r)^{2004-t}}$$

where:

$Cost_{x,t}$	=	Costs in category x and year t
x	=	Cost category
r	=	Discount rate (7% in this analysis)
t	=	Year in which cost is incurred (2004 to 2012)

b. Annualization of compliance costs

Annualized compliance costs include all capital costs, O&M costs, administrative costs, energy penalty costs, and plant outage costs of compliance with the proposed Phase II rule and alternative regulatory options. O&M costs include the cost of auxiliary power requirements as a result of the operation of recirculating cooling towers. To derive the constant annual value of the capital costs and the value of the cooling tower construction and/or connection plant outage, EPA annualized them over 30 years, using a seven percent discount rate. The costs of condenser upgrades were annualized over 20 years. Other capital costs, which include fine-mesh traveling screens with and without fish handling as well as fish handling and return systems, were annualized over 10 years. EPA calculated the annualized capital costs using the following formula:

$$Annualized\ Capital\ Cost = Total\ Capital\ Costs \times \frac{r \times (1 + r)^n}{(1 + r)^n - 1}$$

where:

r	=	Discount rate (7% in this analysis)
n	=	Amortization period (useful life of equipment; 30 years for cooling tower equipment; 20 years for condensers; 10 years for other flow reduction and I&E technologies)

EPA then added the annualized capital and outage costs to annual O&M, administrative costs and energy penalty costs to derive each facility's total annual cost of complying with the proposed Phase II rule.

c. Consideration of taxes

Compliance costs associated with the section 316(b) regulation reduce the income of facilities subject to the rule. As a result, the tax liability of these facilities decreases. The net cost of the rule to facilities is therefore the compliance costs of the rule less the tax savings that result from these compliance costs. EPA estimated the tax savings by developing a total tax rate that integrates the federal corporate income tax rate (35 percent) and state-specific state corporate income tax rates. The total effective tax rate was calculated as follows:

$$Total\ Tax\ Rate = State\ Tax\ Rate + Federal\ Tax\ Rate - (State\ Tax\ Rate * Federal\ Tax\ Rate)$$

[5] Calculation of the present value assumes that the cost is incurred at the end of the year.

The amount by which a facility's annual tax liability would be reduced is the annualized compliance cost of the rule multiplied by the total tax rate.[6]

B1-3.2 Total Private Costs of the Proposed Rule

EPA estimates that the total annual facility compliance cost of the proposed Phase II rule for the 550 in-scope facilities is $182 million annually. Table B1-6 presents annualized facility compliance costs by cost category and NERC region. The annualized cost by NERC region ranges from approximately $200,000 for facilities located in ASCC to $33 million for facilities located in ECAR.[7]

Table B1-6: Private (Post-Tax) Annualized Facility Compliance Costs by NERC Region (in millions, $2001)

NERC Region	One-Time Costs			Recurring Costs				Total
	Capital Technology	Connection Outage	Initial Permit Application	O&M	Monitoring, Record Keeping & Reporting	Energy Penalty	Permit Renewal	
ASCC	$0.0	$0.0	$0.1	$0.0	$0.1	$0.0	$0.0	**$0.2**
ECAR	$15.2	$0.0	$6.5	$3.6	$5.9	$0.0	$1.4	**$32.6**
ERCOT	$4.6	$0.0	$3.7	$1.2	$3.4	$0.0	$0.8	**$13.8**
FRCC	$7.2	$0.0	$2.5	$1.8	$2.1	$0.0	$0.5	**$14.1**
HI	$1.2	$0.0	$0.2	$0.2	$0.2	$0.0	$0.0	**$1.9**
MAAC	$9.3	$0.0	$2.9	$1.8	$2.5	$0.0	$0.6	**$17.1**
MAIN	$6.4	$0.0	$3.3	$1.4	$3.0	$0.0	$0.7	**$14.8**
MAPP	$2.0	$0.0	$3.1	$0.4	$2.9	$0.0	$0.7	**$9.1**
NPCC	$13.3	$0.0	$4.3	$2.7	$3.7	$0.0	$0.8	**$24.9**
SERC	$14.7	$0.0	$6.4	$3.9	$5.9	$0.0	$1.4	**$32.3**
SPP	$1.3	$0.0	$2.2	$0.4	$2.1	$0.0	$0.5	**$6.4**
WSCC	$8.2	$0.0	$2.6	$1.5	$2.2	$0.0	$0.5	**$15.1**
Total	**$83.5**	**$0.0**	**$37.8**	**$19.0**	**$34.1**	**$0.0**	**$8.0**	**$182.4**

Source: U.S. EPA analysis, 2002.

Table B1-7 presents total annual facility compliance costs by cost category and steam plant type. The annual compliance costs range from approximately $2 million for waste facilities to $91 million for coal facilities.

[6] This calculation is a conservative approximation of the actual tax effect of the compliance costs. For capital costs, it assumes that the total annualized cost, which includes imputed interest and principal charge components, is subject to a tax benefit. In effect, the schedule of principal charges *over time* in the annualized cost value is treated, for tax purposes, as though it were the depreciation schedule *over time*. In fact, the actual tax depreciation schedule that would be available to a company would be accelerated in comparison to the principal charge schedule embedded in the annualized cost calculation. As a result, explicit accounting for the deprecation schedule would yield a slightly higher present value of tax benefits than is reflected in the analysis presented here.

[7] See definitions of NERC regions in section B1-2.

Table B1-7: Private (Post-Tax) Annualized Facility Compliance Costs by Steam Plant Type (in millions, $2001)

Steam Plant Type	One-Time Costs			Recurring Costs				Total
	Capital Technology	Connection Outage	Initial Permit Application	O&M	Monitoring, Record Keeping & Reporting	Energy Penalty	Permit Renewal	
Coal	$38.8	$0.0	$20.1	$9.4	$18.3	$0.0	$4.3	**$90.9**
Combined Cycle	$1.7	$0.0	$1.2	$0.5	$1.0	$0.0	$0.2	**$4.6**
Nuclear	$15.4	$0.0	$3.7	$3.0	$3.3	$0.0	$0.8	**$26.2**
Oil/Gas	$27.2	$0.0	$12.2	$6.0	$10.9	$0.0	$2.5	**$58.9**
Waste	$0.3	$0.0	$0.6	$0.1	$0.5	$0.0	$0.1	**$1.6**
Unspecified	$0.0	$0.0	$0.1	$0.0	$0.1	$0.0	$0.0	**$0.1**
Total	**$83.5**	**$0.0**	**$37.8**	**$19.0**	**$34.1**	**$0.0**	**$8.0**	**$182.4**

Source: U.S. EPA analysis, 2002.

The total costs of the alternative regulatory options are presented in Chapter B7: Alternative Options - Costs and Economic Impacts.

B1-4 Uncertainties and Limitations

EPA's estimates of the compliance costs associated with the proposed Section 316(b) Existing Facilities Rule are subject to limitations because of uncertainties about the number and characteristics of the existing facilities that will be subject to the rule. Projecting the number of existing facilities that meet the design intake flow threshold is subject to uncertainties associated with the quality of data reported by the facilities in their DQ and STQ surveys, and with the accuracy of the design flow estimates for the STQ facilities. Characterizing the cooling systems and intake technologies in use at existing facilities is also subject to uncertainties associated with the quality of data reported by the facilities in their surveys and with the projected technologies for the STQ facilities. The estimated national facility compliance costs may be over- or understated if the projected number of Phase II existing facilities is incorrect or if the characteristics of the Phase II existing facilities are different from those assumed in the analysis.

There is additional uncertainty about the valuation of the energy penalty and the connection outage. EPA's analysis used historical information on electricity generation, electricity sales, electricity prices, and fuel costs, which may not be representative of conditions at the time when facilities comply with Phase II regulation.

Limitations in EPA's ability to consider a full range of compliance responses may result in an overestimate of facility compliance costs. The Agency was not able to consider certain compliance responses, including the costs of using alternative sources of cooling water, the costs of some methods of changing the cooling system design, and the costs of restoration. Costs will be overstated if these excluded compliance responses are less expensive than the projected compliance response for some facilities.

Alternative less stringent requirements based on both costs and benefits are allowed under the proposed rule. There is some uncertainty in predicting compliance responses because the number of facilities requesting alternative less stringent requirements based on costs and benefits is unknown.

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Appendix to Chapter B1

B1-A.1 Assignment of Compliance Years for Cooling Tower Options

APPENDIX CONTENTS

This section discusses the methodology used to estimate the compliance years of facilities subject to alternative regulatory options that include cooling towers as compliance requirements for some facilities. Under the waterbody/capacity-based option (Option 1), facilities that withdraw cooling water from oceans or estuaries and have certain intake flow characteristics are required to reduce flow to a level commensurate with that of wet cooling towers; EPA costed 54 facilities with cooling towers under this option. The all cooling towers option (Option 4) requires that all facilities that do not currently have a cooling tower to install one; EPA costed 426 facilities with cooling towers under this option. Due to the longer lead-time required to design and install cooling towers, facilities that install cooling towers have a longer time frame within which to comply with a policy option. Facilities not costed with a cooling tower have the same compliance years as described in Section B1-2 of this chapter.

B1-A.1.1 Methodology

Under a regulatory option that would require facilities to reduce their flow to a level commensurate to a closed-cycle recirculating system, a facility installing a cooling tower would have to comply by the end of the first permit issued after the Phase II promulgation date (August 28, 2003). Facilities that got their last NPDES permit in 1999 would receive their first post-promulgation permit in 2004 and would have until the end of that permit term, 2008, to comply with the rule.[8] Similarly, facilities that get a new permit in 2003 would receive their first post-promulgation permit in 2008 and have until the end of that permit term, 2012, to comply with the rule. Therefore, for facilities costed with a cooling tower, the latest possible year of compliance with the proposed rule ranges from 2008 to 2012. Since facilities have the option to comply earlier, the potential compliance period for facilities costed with a cooling tower would be between 2004 and 2012. This analysis assumes that each facility costed with a cooling tower would comply during the five-year term of its first post-promulgation permit.

At a large electric generating plant, a cooling tower takes approximately two years to design, construct, and then connect (U.S. EPA-U.S. DOE personal correspondence, 2002). In the first year, engineers prepare for the construction of a cooling tower. In the second year, the cooling tower is installed. A facility that is issued its first post-promulgation permit in 2004 could do the preparation work in that year and install their cooling tower in 2005. Therefore, the compliance period for facilities costed with a cooling tower is 2005 to 2012. EPA obtained NPDES permit information from its Permit Compliance System (PCS) database, using NPDES permit ID's from the 1994 UDI database or Envirofacts.[9]

Table B1-A-1 below presents the five-year compliance period for facilities costed with a cooling tower, based on the year of their last NPDES permit.

[8] The dates used for this analysis are based on a five-year permit term. For the purpose of analysis simplicity, we assume that each facility's permit period will begin on January 1st and end on December 31st.

[9] NPDES permit IDs could not be identified for eight facilities. EPA randomly assigned these facilities to a compliance year.

Table B1-A-1: Compliance Schedule for Facilities Costed with Cooling Towers

Year of Last NPDES Permit	Compliance Period		
	Year of First Post-Promulgation Permit	First Year of Cooling Tower Installation	Last Year of Cooling Tower Installation
1999	2004	2005	2008
2000	2005	2005	2009
2001	2006	2006	2010
2002	2007	2007	2011
2003	2008	2008	2012

Source: U.S. EPA analysis, 2002.

The following subsections explain how a specific compliance year was identified from the five-year compliance period available to each facility.

a. Nuclear facilities

Periodic in-service inspections (ISIs) are typically performed at nuclear power plants at five- and ten-year intervals. Five-year ISIs are scheduled for the 5th, 15th, 25th, and 35th years of a plant's operation, and ten-year ISIs are performed in the 10th, 20th, and 30th years. Each of these outages typically requires two to four months of downtime for the plant. EPA assumed that all nuclear facilities costed with cooling towers will install them at times that coincide with their ISIs. This analysis used Forms EIA-860A and EIA-860B to identify the year that each non-retired nuclear unit began operation. When a facility has more than one unit, it was assumed that the ISIs would occur during five-year intervals from the time that the earliest unit began operation. The compliance year used in the analysis is therefore a five-year multiple of the first year of operation of each nuclear facility. The compliance year is additionally constrained by the NPDES permitting schedule, as described above. For example, for a facility which has two active generating units that began operation in 1983 and 1984, EPA assumed that the facility is on an inspection schedule which began in 1983, with inspections occurring in five-year intervals. The facility's current NPDES permit expires in 2005. Therefore, this analysis assumes that the facility would install a cooling tower in 2008, which is 25 years after the facility began operation and occurs during its first post-promulgation permit period (2005 to 2009).

b. Other facilities

Information on routine maintenance shut-downs is not available for non-nuclear facilities, so the algorithm used to determine the compliance year of nuclear facilities could not be used for non-nuclear facilities. Instead, EPA used NPDES permit expiration dates to estimate compliance years. EPA assigned the non-nuclear cooling tower facilities to compliance years so that the capacity and steam electric generating capacity that would be out of service at one time in any NERC region was evenly distributed over the compliance period (2005-2012). In doing so, EPA also took into account the nuclear capacity that would be out of service.

The methodology used to assign compliance years to facilities may not accurately predict the actual shut-down time for any given facility, but it is unbiased and provides a reasonable estimate of national costs.

B1-A.1.2 Summary of Cooling Tower Facilities by Compliance Year

a. Waterbody/capacity-based option

This option would require existing facilities located on estuaries and tidal rivers to reduce intake capacity commensurate with the use of a closed-cycle recirculating cooling system. EPA analyzed two different cases of the waterbody/capacity based option: the first case assumes that all 54 facilities with recirculating cooling system-based requirements would comply with Track I and install a wet cooling tower (Option 1); the second, more likely, case assumes that 21 of the 54 facilities with recirculating cooling system-based requirements would comply with Track II. These 21 facilities would conduct a comprehensive waterbody characterization study and install technologies other than wet cooling towers (Option 2). The following tables and discussion present only the Option 1 analysis. The 33 facilities assumed to install a wet cooling tower under Option 2 are a subset of the 54 facilities analyzed with the wet cooling tower technology in Option 1 and the compliance results for the Option 2 case are less than those presented for the Option 1 case.

The 54 facilities that were costed with a cooling tower in Option 1 account for 62,500 MW of baseline steam capacity. The following three tables present the distribution of capacity costed with a cooling tower by (1) NERC region and steam plant type, (2) NERC region and estimated compliance year, and (3) steam plant type and estimated compliance year.

Table B1-A-2: Weighted Baseline Steam Capacity (MW) by NERC Region and Steam Plant Type

NERC Region	Steam Plant Type					
	Coal	Combined-Cycle	Nuclear	Oil	Other Steam	Total
ERCOT	0	0	0	0	3,902	**3,902**
FRCC	6,651	0	1,700	3,132	0	**11,483**
HI	0	0	0	1,085	0	**1,085**
MAAC	4,346	219	4,211	1,769	0	**10,544**
NPCC	2,927	600	3,076	4,842	3,529	**14,974**
SERC	2,612	0	3,485	0	2,051	**8,148**
WSCC	0	0	4,555	0	7,807	**12,362**
Total	**16,537**	**819**	**17,027**	**10,827**	**17,289**	**62,497**

Source: U.S. EPA analysis, 2002.

Table B1-A-3: Weighted Baseline Steam Capacity (MW) by NERC Region and Compliance Year

Compliance Year	NERC Region							
	ERCOT	FRCC	HI	MAAC	NPCC	SERC	WSCC	Total
2005	0	1,112	610	1,829	0	2,301	1,656	**7,508**
2006	0	1,700	0	1,229	0	3,426	2,396	**8,751**
2007	0	1,320	475	2,382	1,695	1,295	1,317	**8,483**
2008	0	3,333	0	1,767	812	2,254	625	**8,791**
2009	426	0	0	768	2,051	1,447	2,591	**7,283**
2010	514	0	0	1,059	1,790	1,639	3,326	**8,327**
2011	647	1,998	0	801	1,800	0	1,124	**6,370**
2012	2,315	2,019	0	710	0	0	1,940	**6,984**
Total	**3,902**	**11,483**	**1,085**	**10,544**	**8,148**	**12,362**	**14,974**	**62,497**

Source: U.S. EPA analysis, 2002.

Table B1-A-4: Weighted Baseline Steam Capacity (MW) by Steam Plant Type and Compliance Year

Compliance Year	Steam Plant Type					
	Coal	Combined-Cycle	Nuclear	Oil	Other Steam	Total
2005	987	0	4,129	1,722	669	**7,508**
2006	1,229	0	1,700	1,516	4,306	**8,751**
2007	1,320	0	4,898	475	1,790	**8,483**
2008	5,694	819	2,254	0	25	**8,791**
2009	768	0	0	1,242	5,273	**7,283**
2010	0	0	3,032	3,142	2,152	**8,327**
2011	4,599	0	1,013	0	758	**6,370**
2012	1,940	0	0	2,730	2,315	**6,985**
Total	**16,537**	**819**	**17,027**	**10,827**	**17,289**	**62,497**

Source: U.S. EPA analysis, 2002.

b. All cooling towers option

To comply with the all cooling towers option, EPA estimated that 426 facilities would need to install cooling towers. These facilities account for 353,750 MW of baseline steam capacity. The following three tables present the distribution of capacity costed with a cooling tower by (1) NERC region and steam plant type, (2) NERC region and estimated compliance year, and (3) steam plant type and estimated compliance year.

Table B1-A-5: Weighted Baseline Steam Capacity (MW) by NERC Region and Steam Plant Type

NERC Region	Steam Plant Type					
	Coal	Combined- Cycle	Nuclear	Oil	Other Steam	Total
ASCC	28	0	0	0	0	**28**
ECAR	55,762	0	3,503	1,953	0	**61,218**
ERCOT	7,237	110	2,430	22,940	0	**32,717**
FRCC	7,666	3,402	1,700	10,252	0	**23,021**
HI	0	0	0	1,189	0	**1,189**
MAAC	8,685	219	7,155	6,664	262	**22,985**
MAIN	25,661	0	4,921	0	0	**30,581**
MAPP	12,702	0	3,075	197	0	**15,973**
NPCC	7,867	1,105	10,430	20,104	282	**39,787**
SERC	57,496	127	23,699	16,050	0	**97,373**
SPP	6,456	0	0	2,149	0	**8,605**
WSCC	2,183	344	4,555	13,186	0	**20,267**
Total	**191,742**	**5,306**	**61,468**	**94,685**	**543**	**353,745**

Source: U.S. EPA analysis, 2002.

Table B1-A-6: Weighted Baseline Steam Capacity (MW) by NERC Region and Compliance Year

Comp-liance Year	NERC Region												
	ASCC	ECAR	ERCOT	FRCC	HI	MAAC	MAIN	MAPP	NPCC	SERC	SPP	WSCC	Total
2005	0	7,090	5,559	3,245	714	2,312	6,588	948	3,711	9,288	1,309	3,497	**44,263**
2006	28	6,832	4,789	1,842	0	2,425	5,159	2,233	4,262	12,312	816	3,937	**44,636**
2007	0	8,439	3,179	1,551	475	5,295	4,137	784	3,337	12,736	386	3,866	**44,186**
2008	0	6,423	3,708	3,414	0	2,603	3,004	2,995	4,332	14,026	562	3,824	**44,892**
2009	0	6,078	3,238	2,250	0	4,279	4,265	2,634	8,574	10,763	654	2,373	**45,109**
2010	0	8,480	2,998	2,852	0	4,105	2,085	2,055	7,205	13,738	2,044	1,639	**47,200**
2011	0	8,573	3,442	3,361	0	1,256	1,605	1,431	4,461	15,987	1,220	25	**41,362**
2012	0	9,304	5,803	4,504	0	710	3,737	2,893	3,905	8,523	1,613	1,105	**42,098**
Total	**28**	**61,218**	**32,717**	**23,021**	**1,189**	**22,985**	**30,581**	**15,973**	**39,787**	**97,373**	**8,605**	**20,267**	**353,745**

Source: U.S. EPA analysis, 2002.

Table B1-A-7: Weighted Baseline Steam Capacity (MW) by Steam Plant Type and Compliance Year

Compliance Year	Steam Plant Type					
	Coal	Combined-Cycle	Nuclear	Oil	Other Steam	Total
2005	25,795	127	9,416	8,924	0	**44,263**
2006	27,043	0	7,229	10,364	0	**44,636**
2007	22,078	1,430	8,069	12,354	254	**44,186**
2008	23,793	1,162	7,383	12,444	110	**44,892**
2009	14,851	218	16,045	13,925	68	**45,109**
2010	20,501	0	9,872	16,827	0	**47,200**
2011	29,028	382	3,454	8,386	111	**41,362**
2012	28,651	1,986	0	11,460	0	**42,098**
Total	**191,742**	**5,306**	**61,468**	**94,685**	**543**	**353,745**

Source: U.S. EPA analysis, 2002.

c. Dry cooling

Compliance year assignments for the dry cooling option (Option 5) are identical to those for facilities in the waterbody/capacity-based option (Option 1), assuming that all facilities will go track 1 and install cooling towers.

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Chapter B2: Cost Impact Analysis

Introduction

Chapter Contents

This chapter presents an assessment of the magnitude of compliance costs associated with the Proposed Section 316(b) Phase II Existing Facilities Rule, including a cost-to-revenue analysis at the facility and firm levels, a state-level analysis of compliance costs per household, and an analysis of compliance costs relative to electricity price projections at the North American Electric Reliability Council (NERC) level. Later chapters consider the potential energy effects of the proposed rule on regional energy markets and facilities subject to Phase II regulation (*Chapter B3: Electricity Market Model Analysis*), impacts on small entities (*Chapter B4: Regulatory Flexibility Analysis*), and impacts on governments (*Chapter B5: UMRA Analysis*). *Chapter B7: Alternative Options - Costs and Economic Impacts* evaluates the magnitude of four other regulatory alternatives considered by EPA.

Based on the analyses presented in this chapter, EPA concludes that compliance with this proposed rule is both economically practicable and achievable.[1]

B2-1 Cost-to-Revenue Measure

The "cost-to-revenue measure" is used to assess the magnitude of compliance costs relative to revenues. This test is commonly used to evaluate the economic practicability of regulatory requirements. The cost-to-revenue measure is a useful test because it compares the cost of reducing adverse environmental impact from the operation of the facility's cooling water intake structure (CWIS) with the economic value (i.e., revenue) of the facility's economic activities. EPA conducted this test at the facility and firm levels.

Depending on the policy option analyzed, annualized compliance costs include all capital costs, O&M costs, administrative costs, energy penalty costs, and plant outage costs of compliance with the proposed Phase II rule. O&M costs include the cost of auxiliary power requirements as a result of the operation of recirculating cooling towers. To derive the constant annual value of the capital costs and the value of the cooling tower construction and/or connection plant outage, EPA annualized them over 30 years, using a seven percent discount rate. The costs of condenser upgrades were annualized over 20 years. Other capital costs, which include fine-mesh traveling screens with and without fish handling as well as fish handling and return systems, were annualized over 10 years. EPA then added the annualized capital and connection outage costs to annual O&M costs, administrative costs, and the cost of the energy penalty to derive each facility's total annual cost of complying with the Phase II rule.[2] For a detailed analysis of the compliance cost components developed for this analysis, see *Chapter B1: Summary of Compliance Costs* and the *§ 316(b) Technical Development Document*.

EPA compared the annualized compliance costs to the estimated facility and firm revenues to determine the economic practicability of the proposed Phase II rule on both the facility and firm levels. This analysis uses impact thresholds of one and three percent.

[1] It should be noted that the following measures are intended to give an indication of the magnitude of compliance costs. These measures are not used to predict closures or other types of economic impacts on facilities subject to the proposed Phase II rule. EPA did not rely on any one of these measures to assess the magnitude of costs.

[2] This annualization methodology is different from that conducted for the national cost estimate presented in *Chapter B1: Overview of Costs and Economic Impacts*. For the national cost estimate, the present value was determined as of the first year the Phase II rule will take effect (2004). In contrast, for the impact analysis, the present value was determined as of the first year of compliance of each facility (2004 to 2012).

B2-1.1 Facility Analysis

To estimate the impact on facilities due to the proposed Phase II rule, EPA compared the annualized post-tax compliance costs of the proposed rule as a percentage of annual revenues for each of the 550 in-scope facilities. EPA used facility-specific revenue projections from ICF Consulting's Integrated Planning Model (IPM®) for 2008 for this analysis. The IPM did not provide revenues for 21 of the 550 in-scope facilities. Eleven of these facilities are estimated to be baseline closures and 10 facilities were not modeled by the IPM. In addition, 9 facilities were projected by IPM to have zero baseline revenues. EPA used facility-specific electricity generation and firm-specific wholesale prices as reported to the Energy Information Administration (EIA) to calculate the cost-to-revenue ratio for the 19 non-baseline closure facilities with missing information. The revenues for one of these facilities remained unknown.

Table B2-1 below presents the results of the facility-level cost-to-revenue measure conducted for the 550 electric generating facilities subject to the Phase II rule, by facility ownership type and fuel type. For each facility type the table presents (1) the total number of facilities; (2) the number of facilities with a cost-to-revenue ratio of less than 0.5 percent, between 0.5 and one percent, between one and three percent, and greater than three percent; and (3) the minimum and maximum ratio.

Table B2-1: Facility-Level Cost-to-Revenue Measure

Facility Type	Total Number of Facilities	Number of Facilities with a Ratio of						Minimum Ratio	Maximum Ratio
		<0.5%	0.5 -1%	1 - 3%	> 3%	Baseline Closure	n/a		
By Ownership Type									
Investor-Owned Utility	313	218	39	37	12	6	1	0.02%	15.8%
Federal Utility	13	12	1	-	-	-	-	0.07%	0.5%
State-Owned Utility	6	3	2	1	-	-	-	0.09%	1.9%
Political Subdivision	8	4	-	2	1	1	-	0.07%	28.0%
Municipality & Municipal Marketing Authority	50	13	6	16	15	-	-	0.09%	34.3%
Rural Electric Cooperative	25	10	4	6	5	-	-	0.09%	9.0%
Nonutility (former utility)	120	69	24	15	8	4	-	0.02%	6.4%
Nonutility (original)	14	2	2	5	5	-	-	0.29%	12.1%
Total[a]	**550**	**331**	**78**	**82**	**46**	**11**	**1**	**0.02%**	**32.3%**
By Fuel Type									
Coal	299	218	44	26	10	-	-	0.02%	12.1%
Combined-Cycle	16	6	3	3	3	-	-	0.04%	11.5%
Nuclear	57	47	2	-	-	8	-	0.02%	0.8%
Oil	169	60	26	48	31	3	-	0.05%	34.3%
Other Steam	8	-	2	5	1	-	-	0.51%	4.5%
Unknown	1	-	-	-	-	-	1	n/a	n/a
Total[a]	**550**	**331**	**78**	**82**	**46**	**11**	**1**	**0.02%**	**32.3%**

[a] Individual numbers may not add up due to independent rounding.

Source: IPM analysis: model run for Section 316(b) base case; U.S. EPA analysis, 2002.

Table B2-1 shows that the vast majority of facilities subject to the proposed Phase II rule incur very low compliance costs when compared to facility-level revenues. Out of the 550 facilities subject to the proposed Phase II rule, 409, or approximately 74 percent, incur annualized costs of less than 1 percent of revenues. Of these, 331, or approximately 60 percent, incur annualized costs of less than 0.5 percent of revenues. Eighty-two facilities, or 15 percent would incur costs of between 1 and 3 percent of revenues, and 46 facilities, or 8 percent, would incur costs of greater than 3 percent. EPA estimates that eleven facilities would be baseline closures, and for one facility, revenues are unknown. Based on these results, EPA concludes that the proposed Phase II rule would be economically practicable at the facility level.

B2-1.2 Firm Analysis

The facility-level analysis above showed that compliance costs are low compared to facility-level revenues. However, impacts experienced at the firm-level may be significant for firms that own multiple facilities subject to the proposed Phase II rule. EPA therefore also analyzed the economic practicability of the proposed Phase II rule at the firm level.

To evaluate the economic practicability of this rule on the firms owning the in-scope facilities, EPA first identified the domestic parent entity of each in-scope Phase II facility. For a detailed description of how EPA identified the domestic parent entity of each in-scope facility, see *Chapter B4: Regulatory Flexibility Analysis.* From this analysis, EPA identified the 131 unique domestic parent entities owning facilities subject to the proposed Phase II regulation. EPA obtained the sales revenues for the 131 domestic parent entities from publicly available data sources (the 1999 Forms EIA-860A, EIA-860B, and EIA-861; and the Dun and Bradstreet database) as well as EPA's 2000 Section 316(b) Industry Survey. The firm-level analysis is based on the aggregated post-tax compliance costs for each facility owned by the 131 parent entities to the firm's total sales revenue. EPA identified 70 entities, out of the 131 unique domestic parent entities, that own more than one facility subject to the proposed Phase II rule.

Table B2-2 below summarizes the results of the cost-to-revenue measure conducted for the 131 entities owning in-scope electric generating facilities by the parent entity type. For each entity type the table presents (1) the total number of facilities owned; (2) the total number of firms; (3) the number of firms with a cost-to-revenue ratio of less than 0.5 percent, between 0.5 and one percent, between one and three percent, greater than three percent; and (4) the minimum and maximum ratio.

Table B2-2: Firm-Level Cost-to-Revenue Measure by Entity Type

Entity Type	Total Number of Facilities	Total Number of Firms	Number of Firms with a Ratio of					Minimum Ratio	Maximum Ratio
			<0.5%	0.5-1%	1 - 3%	> 3%	Baseline Closure		
Municipality & Municipal Marketing Authority	50	37	18	8	8	3	-	0.05%	5.29%
Political Subdivision	8	4	3	-	1	-	-	0.03%	1.22%
Rural Electric Cooperative	25	15	12	2	1	-	-	0.06%	1.41%
State	7	4	2	2	-	-	-	0.10%	0.84%
Federal	13	1	1	-	-	-	-	0.16%	0.16%
Private	446	70	68	-	-	-	2	0.00%	0.44%
Total[a]	**550**	**131**	**104**	**12**	**10**	**3**	**2**	**0.00%**	**5.29%**

[a] Individual numbers may not add up to totals due to independent rounding.

Source: IPM analysis: model run for Section 316(b) base case; EPA analysis, 2002.

EPA estimates that the compliance costs will comprise a very low percentage of firm-level revenues. Of the 131 unique entities with facilities subject to the proposed Phase II rule, 116, or approximately 89 percent, incur annualized costs of less than 1 percent of revenues. Of these, 104, or approximately 79 percent, incur annualized costs of less than 0.5 percent of revenues. Ten entities would incur costs of between 1 and 3 percent of revenues, and only three entities would incur costs of greater than 3 percent. EPA estimates that two entities only own facilities projected to be baseline closures. For both entities, the compliance costs incurred would have been less than 0.5 percent of revenues. Overall, the estimated annualized compliance costs represent between 0.002 and 5.3 percent of the entities' annual sales revenue. Based on the results from this analysis, EPA concludes that the proposed Phase II rule would be economically practicable at the firm level.

B2-2 Cost Per Household

EPA also conducted an analysis that evaluates the potential cost per household[3], if Phase II facilities were able to pass compliance costs on to their customers. This analysis estimates the average compliance cost per household for each NERC region, using two data inputs: (1) the average annual compliance cost per megawatt hour (MWh) of sales and (2) the average annual MWh of electricity sales per household. Both data elements were calculated by NERC region using the following approach.

Average annual compliance cost per MWh of sales: EPA compiled data on total electricity sales (including residential, commercial, industrial, public street highway and lighting, and other sales) from the 2000 Form EIA-861 database. Utility-level sales were aggregated by NERC region to derive each region's total electricity sales in 2000. In addition, EPA aggregated the national pre-tax compliance costs by the NERC region in which the 550 Phase II facilities are located. The average compliance cost per MWh of electricity sales is calculated by dividing total electricity sales by total pre-tax compliance costs for each region.

Average annual electricity sales per household: Form EIA-861 differentiates electricity sales by customer type and also presents the number of customers that account for the sales. The average annual electricity sales per household is therefore calculated by dividing the MWh of residential sales by the number of households. This calculation was again done by NERC region.

EPA calculated the annual cost of the proposed rule per household by multiplying the average annual compliance cost per MWh of sales by the average annual electricity sales per household. This analysis assumes that power generators pass costs on to consumers, on a dollar-to-dollar basis, and that each sector (i.e., residential, industrial, commercial, public street highway and lighting, and other) bears an equal burden of compliance costs per MWh of electricity.

Table B2-3 shows the results of this analysis: the cost per residential consumer would range from $0.33 per year in ASCC to $2.55 per year in HI. Regions with electricity use higher than the average (ERCOT, FRCC, SERC, and SPP) are regions with warm climates where air conditioning use is high.

[3] The number of residential consumers reported in Form EIA-861 is based on the number of utility meters. This is a proxy for the number of households but can differ slightly due to bulk metering in some multi-family housing.

Table B2-3: Annual Compliance Cost per Residential Consumer by NERC Region in 2000

NERC Region [a]	Total Electricity Sales (MWh)	Total National Pre-Tax Compliance Cost	Annualized Pre-Tax Compliance Cost ($ / MWh Sales)	Residential Electricity Sales (MWh)	Number of Households	Annual Residential Sales/ Consumer (MWh)	Annual Compliance Cost/ Residential Consumer
ASCC	5,309,970	$215,459	$0.04	1,854,968	230,534	8.05	$0.33
ECAR	522,187,334	$51,335,018	$0.10	158,037,771	15,626,013	10.11	$0.99
ERCOT	285,347,453	$19,569,370	$0.07	103,478,697	7,021,590	14.74	$1.01
FRCC	182,848,371	$20,999,501	$0.11	92,391,451	6,721,120	13.75	$1.58
HI	9,271,676	$3,108,587	$0.34	2,627,203	344,882	7.62	$2.55
MAAC	229,193,120	$28,742,057	$0.13	82,890,271	8,982,600	9.23	$1.16
MAIN	247,759,377	$23,384,949	$0.09	72,946,752	8,188,189	8.91	$0.84
MAPP	139,246,194	$12,444,394	$0.09	47,997,755	4,848,274	9.90	$0.88
NPCC	256,382,568	$41,090,108	$0.16	85,806,190	12,650,908	6.78	$1.09
SERC	764,593,949	$45,131,984	$0.06	282,503,216	20,192,159	13.99	$0.83
SPP	171,473,599	$8,952,539	$0.05	59,902,473	4,909,350	12.20	$0.64
WSCC	599,645,124	$23,714,787	$0.04	201,895,024	22,010,686	9.17	$0.36
U.S.	**3,413,258,735**	**$278,688,755**	**$0.08**	**1,192,331,771**	**111,726,305**	**10.67**	**$0.87**

[a] **Key to NERC regions:** ASCC – Alaska Systems Coordinating Council; ECAR – East Central Area Reliability Coordination Agreement; ERCOT – Electric Reliability Council of Texas; FRCC – Florida Reliability Coordinating Council; HI – Hawaii; MAAC – Mid-Atlantic Area Council; MAIN – Mid-America Interconnect Network; MAPP – Mid-Continent Area Power Pool; NPCC – Northeast Power Coordinating Council; SERC – Southeastern Electric Reliability Council; SPP – Southwest Power Pool; WSCC – Western Systems Coordinating Council.

Source: U.S. DOE, 2000; EPA analysis, 2002.

B2-3 Electricity Price Analysis

EPA also considered potential effects of the proposed Phase II rule on electricity prices. EPA used three data inputs in this analysis: (1) total pre-tax compliance cost incurred by facilities subject to the proposed rule, (2) total electricity sales, based on the Annual Energy Outlook (AEO) 2002 , and (3) prices by consumer type (residential, commercial, industrial, and transportation), also from the AEO 2002. All three data elements were calculated by NERC region.[4]

Table B2-4 shows the annualized costs of complying with the proposed Phase II rule, total electricity sales (MWh), and the cost in cents per kilowatt hour (KWh) of total electricity sales by NERC region. The costs range from 0.004 cents per KWh sales in WSCC to 0.017 cents per KWh sales in NPCC.

Table B2-4: Compliance Cost per KWh of Sales by NERC Region

NERC Region	Annualized Pre-Tax Compliance Costs (National; $2001)	Total Electricity Sales (MWh; 2000)	Annualized Pre-Tax Compliance Cost (Cents / KWh Sales)
ASCC	$215,459	---	---
ECAR	$51,335,018	517,730,286	0.010
ERCOT	$19,569,370	269,072,083	0.007
HI	$3,108,587	---	---
MAAC	$28,742,057	246,302,490	0.012
MAIN	$23,384,949	231,949,219	0.010
MAPP	$12,444,394	153,681,396	0.008
NPCC	$41,090,108	243,035,378	0.017
FRCC	$20,999,501	182,241,013	0.012
SERC	$45,131,984	759,772,644	0.006
SPP	$8,952,539	171,100,266	0.005
WSCC	$23,714,787	627,001,373	0.004
U.S.	**$278,688,755**	**3,418,263,184**	**0.008**

Source: U.S. DOE, 2001; U.S. EPA analysis, 2002.

To determine potential effects on electricity prices as a result of the proposed rule, EPA compared the compliance cost per KWh of sales, presented in Table B2-4, to baseline electricity prices. Table B2-5 shows the annualized pre-tax compliance cost in cents per KWh of electricity sales and the AEO projected electricity prices for each consumer type. In addition, the table presents the price increase by consumer type that would result from the proposed Phase II rule. The largest potential increase in electricity prices would be 0.31 percent cents per KWh for an industrial facility in NPCC. The average increase in electricity prices would only be between 0.09 percent for households (0.008 / 8.81) and 0.17 percent for industrial customers (0.008 / 4.88).

This analysis assumes that power generators fully recover compliance costs from consumers and that each sector (i.e., residential, commercial, industrial, and transportation) bears an equal burden of compliance costs per MWh of purchased electricity.

[4] The Annual Energy Outlook does not include two NERC regions, ASCC and HI.

Table B2-5: Estimated Price Increase as a Percent of 2000 Prices by Consumer Type and NERC Region[a]

Region	Annualized Pre-Tax Compliance Cost (Cents / KWh Sales)	Residential		Commercial		Industrial		Transportation		All Sectors Average	
		Price	% Change	Price	% Change	Price	% Change	Price	% Change	Price	% Change
ECAR	0.010	8.04	0.12%	7.43	0.13%	4.63	0.21%	7.08	0.14%	6.44	0.15%
ERCOT	0.007	8.35	0.09%	7.40	0.10%	4.35	0.17%	6.54	0.11%	6.80	0.11%
MAAC	0.012	10.43	0.11%	9.19	0.13%	7.09	0.16%	9.13	0.13%	9.11	0.13%
MAIN	0.010	9.09	0.11%	7.60	0.13%	5.03	0.20%	7.55	0.13%	7.13	0.14%
MAPP	0.008	8.27	0.10%	6.82	0.12%	4.62	0.18%	6.76	0.12%	6.43	0.13%
NPCC	0.017	11.42	0.15%	8.40	0.20%	5.52	0.31%	8.33	0.20%	8.93	0.19%
FRCC	0.012	8.30	0.14%	7.17	0.16%	5.31	0.22%	6.49	0.18%	7.60	0.15%
SERC	0.006	7.33	0.08%	6.52	0.09%	4.20	0.14%	5.63	0.11%	6.08	0.10%
SPP	0.005	7.14	0.07%	6.08	0.09%	4.03	0.13%	5.14	0.10%	5.86	0.09%
WSCC	0.004	9.17	0.04%	8.03	0.05%	5.08	0.07%	6.83	0.06%	7.58	0.05%
U.S.	**0.008**	**8.81**	**0.09%**	**8.00**	**0.10%**	**4.88**	**0.17%**	**7.88**	**0.10%**	**7.31**	**0.11%**

[a] Prices are in cents per KWh.

Source: EPA analysis, 2002.

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Chapter B3: Electricity Market Model Analysis

Introduction

The proposed section 316(b) Phase II Existing Facilities Rule applies to a subset of facilities within the electric power generation industry. The proposed rule applies to steam electric generating units that use cooling water withdrawn directly from waters of the U.S. Generating units with a non-steam prime mover and those steam units that use cooling water from a source other than a water of the U.S. are not subject to this rule. In addition, this rule only applies to plants with a design intake flow of at least 50 million gallons per day (MGD). However, due to interdependencies within the electric power market, impacts on in-scope facilities may result in indirect impacts throughout the industry. Direct impacts on plants subject to the rule may include changes in generation, profitability, and capacity utilization. Potential indirect impacts on the electric power industry may include changes to the generation and revenue of facilities and firms not subject to the rule, changes to bulk system reliability, and regional and national impacts such as changes in the price and demand for electricity.

Chapter Contents

EPA used ICF Consulting's Integrated Planning Model (IPM®), an integrated energy market model, to conduct the economic analyses supporting the proposed section 316(b) Phase II Rule. The model addresses the interdependencies within the electric power market and accounts for both direct and indirect impacts of regulatory actions. EPA used the model to analyze two potential effects of the proposed rule and other regulatory options: (1) potential energy effects at the national and regional levels, as required by Executive Order 13211 ("Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use"); and (2) potential economic impacts on in-scope facilities.

The remainder of this chapter presents an overview of the IPM and the results of the IPM analysis for the proposed rule. *Chapter B8: Alternative Options - Electricity Market Model Analysis* presents the IPM analysis for two alternative regulatory options considered by EPA.

B3-1 Summary Comparison of Energy Market Models

EPA conducted research to identify models suitable for analysis of environmental policies that affect the electric power industry. Through a review of forecasting studies and interviews with industry personnel, EPA identified three potential models and considered each for the analyses in support of the proposed Phase II Rule: (1) the Department of Energy's National Energy Modeling System (NEMS), (2) the Department of Energy's Policy Office Electricity Modeling System (POEMS), and (3) ICF Consulting's Integrated Planning Model (IPM). These models are widely used in the analysis of various issues related to public policies affecting the electric power generation industry and have been reviewed.[1]

The three models considered by EPA were developed to meet the specific needs of different users; they therefore differ in terms of structure and functionality. EPA established a set of modeling and logistical criteria to select the model that is best

[1] EPA also considered other models that are more commonly used for private sector analyses but decided to focus its model selection process on models developed for public policy analyses.

suited for the analysis of the proposed rule and alternative regulatory options. Modeling criteria refer to the models' technical capabilities that are required to provide the outputs necessary for the analysis of the proposed rule. They include the following:

- ***Redefining model plants*** – The energy market models considered by EPA aggregate similar generating units into model plants to reduce the amount of time required to run the model. However, such an aggregation is usable only if the aggregated units are similar in the base case and also have similar compliance requirements under the analyzed policy cases. The Phase II compliance requirements of in-scope facilities are based on the location, design, construction, and capacity of their cooling water intake structures (CWIS). In contrast, the existing aggregation of these models is based on factors including unit age, unit type, fuel type, capacity, and operating costs. Therefore, the model used for the Phase II analysis had to be able to accommodate a different aggregation scheme for model plants or even to run all in-scope facilities as separate model plants.

- ***Predicting the economic retirement of generating capacity*** – Compliance with the proposed Phase II Rule may increase the capital and operating costs of some facilities to a point where it is no longer economically profitable to operate the facility, or one or more of its generating units. The economically sound decision for a firm owning such a facility or unit would be to retire the facility or unit rather than comply with the regulation. Therefore, the model needed to have the ability to project early retirements as a result of compliance with the proposed rule and the market's response to such closures, including increased capacity additions or increased market prices. In addition, to support EPA's economic impact analysis, the model had to be able to map early retirements to specific facilities or units.

- ***Representing the impact of structural changes to the industry from deregulation*** – Assumptions regarding deregulation of the electric utility industry could impact a model's ability to accurately depict the profit maximizing decisions of firms. Deregulation of the wholesale market for electricity is expected to reduce wholesale prices as competition in markets increases. These changes may impact decisions regarding the retirement of existing generating units, investment in new generating units, and technology and fuel choices for new generation capacity. Therefore, it was necessary for the market model to reflect the most recent trends in the deregulation of wholesale energy markets.

EPA also considered a number of logistical criteria to determine the most appropriate model for the analyses of the proposed Phase II Rule. While a given model may be desirable from an analytical perspective, its use may be restricted due to other limitations unrelated to the model's capabilities. The logistical criteria used to evaluate each model refer to administrative issues and include the following:

- ***Availability of the model*** – Due to the tight regulatory schedule of the Phase II Rule, the model selected for this analysis had to be accessible at the time data inputs were available, and had to be able to turn around the analyses in a relatively short period of time. Some of the models considered for this analysis are used to conduct analyses in support of annual reports. Such requirements may limit access to the model and the staff required to execute the model, and therefore prevent the use of the model for this analysis.

- ***Sufficient documentation of methods and assumptions*** – Sufficient documentation of the model structure and assumptions was required to allow for the necessary review of results and procedure. While it may not be possible to disclose specific details of the structure and function of a model, a general discussion of the mechanics of the model, its assumptions, inputs, and results was required to make a model useable for this analysis.

- ***Cost –*** EPA considered the cost of using each model together with each model's ability to satisfy the other modeling and logistical criteria in determining the most appropriate model for the analysis of this rule. The model had to be sufficiently robust with respect to the other criteria while remaining within the budget constraints for this analysis.

EPA assessed each market model with respect to the aforementioned modeling and logistical criteria and determined that the IPM was best suited for the Phase II analysis.[2] A principal strength of the IPM as compared to other models is the ability to evaluate impacts to specific facilities subject to this rule. Another important advantage of the IPM model is that it has a history of prior use by EPA. The Agency has successfully used the IPM in support of a number of major air rules. Finally, the IPM model has been reviewed and approved by the Office of Management and Budget (OMB).

[2] Please see Section B3-A.1 of the appendix to this chapter for a comparison of the three electricity market models considered for this analysis.

B3-2 INTEGRATED PLANNING MODEL OVERVIEW

This section presents a general overview of the capabilities of the IPM, including a discussion of the modeling methodology, the specification of the model for the section 316(b) analysis, and model inputs and outputs.

B3-2.1 Modeling Methodology

a. General framework

The IPM is an engineering-economic optimization model of the electric power industry, which generates least-cost resource dispatch decisions based on user-specified constraints such as environmental, demand, and other operational constraints. The model can be used to analyze a wide range of electric power market issues at the plant, regional, and national levels. In the past, applications of the IPM have included capacity planning, environmental policy analysis and compliance planning, wholesale price forecasting, and asset valuation.[3]

The IPM uses a long-term dynamic linear programming framework that simulates the dispatch of generating capacity to achieve a demand - supply equilibrium on a seasonal basis and by region. The model seeks the optimal solution to an "objective function," which is a linear equation equal to the present value of the sum of all capital costs, fixed and variable operation and maintenance (O&M) costs, and fuel costs. The objective function is minimized subject to a series of user-defined supply and demand, or system operating, constraints. Supply-side constraints include capacity constraints, availability of generation resources, plant minimum operating constraints, transmission constraints, and environmental constraints. Demand-side constraints include reserve margin constraints and minimum system-wide load requirements. The optimal solution to the objective function is the least-cost mix of resources required to satisfy system wide electricity demand on a seasonal basis by region. In addition to existing capacity, the model also considers new resource investment options, including capacity expansion or repowering at existing plants as well as investment in new plants. The model selects new investments while considering interactions with fuel markets, capacity markets, power plant cost and performance characteristics, forecasts of electricity demand, reliability criteria, and other constraints. The resulting system dispatch is optimized given the resource mix, unit operating characteristics, and fuel and other costs, to achieve the most efficient use of existing and new resources available to meet demand. The model is dynamic in that it is capable of using forecasts of future conditions to make decisions for the present.[4]

b. Model plants

The model is supported by a database of boilers and electric generation units which includes all existing utility-owned generation units as well as those located at plants owned by independent power producers and cogeneration facilities that contribute capacity to the electric transmission grid. Individual generators are aggregated into model plants with similar O&M costs and specific operating characteristics including seasonal capacities, heat rates, maintenance schedules, outage rates, fuels, and transmission and distribution loss characteristics.

The number and aggregation scheme of model plants can be adjusted to meet the specific needs of each analysis. The EPA Base Case 2000 contains 1,390 model plants.[5]

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[3] The EPA Base Case 2000 is the latest EPA specification of the U.S. power market using the IPM. Past applications of the IPM for EPA analyses have used a predecessor EPA base case specification. Section B3-A.2 of the appendix to this chapter contains a summary of the major differences between the EPA Base Case 2000 and the previous EPA base case specification.

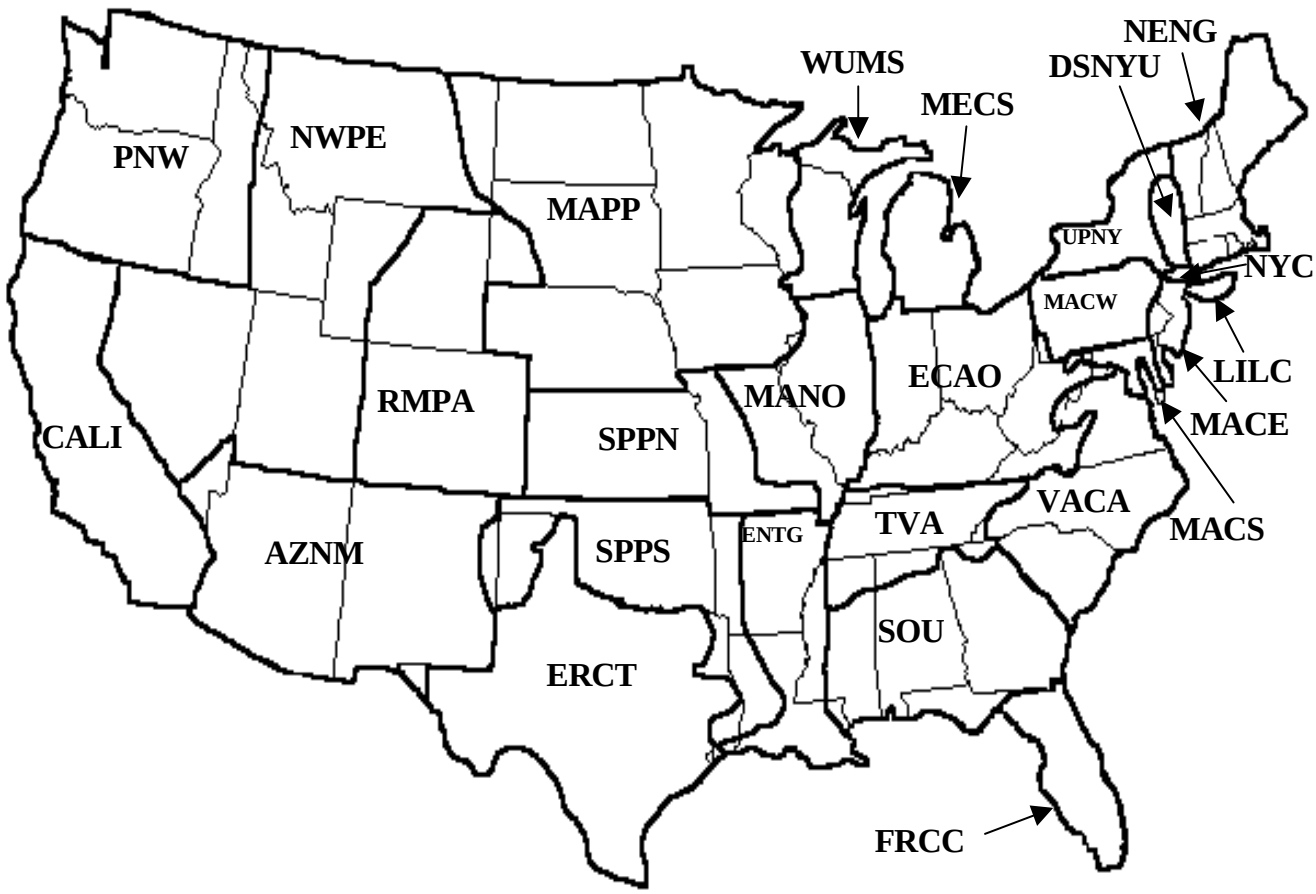
[4] EPA used the IPM to forecast operational changes, including changes in capacity, generation, revenues, electricity prices, and plant closures, resulting from the rule. In other policy analyses, the IPM is generally also used to determine the compliance response for each model facility. This process involves selecting the optimal response from a menu of compliance options that will result in the least-cost system dispatch and new resource investment decision. Compliance options specified by IPM may include fuel switching, repowering, pollution control retrofit, co-firing multiple fuels, dispatch adjustments, and economic retirement. EPA did not use this capability to choose the compliance responses of the facilities subject to section 316(b) regulation. Rather EPA exogenously estimated a compliance response using the costs of technologies capable of meeting the percentage reductions required under the regulation. In the post-compliance analysis, these compliance costs were added as model inputs to the base case operating and capital costs.

[5] Since the EPA Base Case 2000 model plants were initially created to support air policy analyses, the original configuration was not appropriate for the section 316(b) analysis. As a result, in support of this economic analysis, the facilities subject to the Phase II Rule were disaggregated from the IPM model plants and "run" as individual units along with the other model plants.

c. IPM regions

The IPM divides the U.S. electric power market into 26 regions in the contiguous U.S. It does not include generators located in Alaska or Hawaii. The 26 regions map into North American Reliability Council (NERC) regions and sub-regions. The IPM models electric demand, generation, transmission, and distribution within each region and across the transmission grid that connects regions. For the analyses presented in this chapter, IPM regions were aggregated back into NERC regions. Figure B3-1 provides a map of the regions included in the IPM. Table B3-1 presents the crosswalk between NERC regions and IPM regions.

Figure B3-1: Regional Representation of U.S. Power System as Modeled in IPM



Source: U.S. EPA, 2002.

Table B3-1: Crosswalk between NERC Regions and IPM Regions

NERC Region	IPM Regions
ASCC – Alaska	Not Included
ECAR – East Central Area Reliability Coordination Agreement	ECAO, MECS
ERCOT – Electric Reliability Council of Texas	ERCT
FRCC – Florida Reliability Coordinating Council	FRCC
HI – Hawaii	Not Included
MACC – Mid Atlantic Area Council	MACE, MACS, MACW
MAIN – Mid-America Interconnect Network	MANO, WUMS
MAPP – Mid-Continent Area Power Pool	MAPP
NPCC – Northeast Power Coordination Council	DSNY, LILC, NENG, NYC, UPNY
SERC – Southeastern Electricity Reliability Council	ENTG, SOU, TVA, VACA
SPP - Southwest Power Pool	SPPN, SPPS
WSCC – Western Systems Coordinating Council	AZNM, CALI, NWPE, PNW, RMPA

Source: U.S. EPA, 2002.

d. Model run years

The IPM models the electric power market over the 26-year period 2005 to 2030. Due to the data-intensive processing procedures, the model is run for a limited number of years only. Run years are selected based on analytical requirements and the necessity to maintain a balanced choice of run years throughout the modeled time horizon. EPA selected the following run years for this analysis: 2008, 2010, and 2013.[6] Model run year 2008 was selected based on the assumption that all in-scope facilities will be required to comply with the requirements of the proposed rule during the first five years after promulgation in 2003, i.e., 2004 to 2008. Therefore, 2008 represents the long-term, post-compliance state of the industry. Run year 2013 was selected based on the assumption that facilities costed with a cooling tower (a requirement for some facilities under the two alternative options analyzed with the IPM) would have to comply by the end of the permit term of the first permit issued after promulgation, i.e., 2004 to 2012. As installation of a cooling tower may require the temporary shut-down of the facility (this analysis assumes one month of shut-down time), 2013 would represent the first full, post-compliance year for options requiring cooling towers. Run year 2010 was selected as an additional year during which facilities costed with a cooling tower may experience temporary connection outages during cooling tower installation and connection. (For a description of the assignment of compliance years, see *Chapter B1: Summary of Compliance Costs*).

The model assumes that capital investment decisions are only implemented during run years. Each model run year is mapped to several calendar years such that changes in variable costs, available capacity, and demand for electricity in the years between the run years are partially captured in the results for each model run year. Table B3-2 below identifies the model run years specified for the analysis of the proposed rule and other regulatory options, and the calendar years mapped to each.

[6] The IPM developed output for a total of five model run years 2008, 2010, 2013, 2020, and 2026. Model run years 2020 and 2026 were specified for model balance, while run years 2008, 2010, and 2013 were selected to provide output across the compliance period. Output for 2020 and 2026 was not used in this analysis.

Table B3-2: Model Run Year Mapping	
Run Year	**Mapped Years**
2008	2005-2009
2010	2010-2012
2013	2013-2015
2020	2016-2022
2026	2023-2030

Source: IPM model specification for the Section 316(b) Base Case.

EPA mainly relied on data for 2008 in the analyses of the proposed rule (presented in this chapter) and on data for 2013 in the analyses of the alternative regulatory options (presented in *Chapter B7: Alternative Regulatory Options*).

B3-2.2 Specifications for the Section 316(b) Analysis

The analysis of the proposed Phase II Rule and the other regulatory options analyzed with the IPM required changes in the original specification of the IPM model. Specifically, the base case configuration of the model plants and model run years were revised according to the requirements of this analysis. Both modifications to the existing model specifications are discussed below.

- ***Changes in the Aggregation of Model Plants:*** As noted above, the IPM aggregates individual boilers and generators with similar cost and operational characteristics into model plants. Since the IPM model plants were initially created to support air policy analyses, the original configuration was not appropriate for the section 316(b) analysis. As a result, the steam electric generators at facilities subject to the Phase II Rule were disaggregated from the existing IPM model plants and "run" as individual facilities along with the other existing model plants. This change increased the total number of model plants from 1,390 to 1,777.

- ***Use of Different Model Run Years:*** The original specification of the EPA Base Case 2000 of the IPM uses five model run years chosen based on the requirements of various air policy analyses. As EPA assumed that all facilities subject to the proposed rule and other regulatory options would come into compliance within the first permitting cycle after promulgation in 2003 (i.e., 2004 to 2012), the run years specified for the EPA Base Case 2000 are not of primary interest to this analysis. Therefore, EPA selected different run years for the section 316(b) analysis in order to obtain model output throughout the compliance period (see discussion of run year selection in section B3-2.1.d above). The change in run years and run year mappings are summarized below.

Table B3-3: Modification of Model Run Years			
EPA Base Case 2000 Specification		**Section 316(b) Base Case Specification**	
Run Year	**Run Year Mapping**	**Run Year**	**Run Year Mapping**
2005	2005-2007	2008	2005-2009
2010	2008-2012	2010	2010-2012
2015	2013-2017	2013	2013-2015
2020	2018-2022	2020	2016-2022
2026	2023-2030	2026	2023-2030

Source: IPM model specifications for the EPA Base Case 2000 and the Section 316(b) Base Case.

EPA compared the base case results generated from the two different specifications of the IPM model. The base case results could only be compared for those run years that are common to both base cases, 2010 and 2020. This comparison identified little or no difference in the base case results:

- Base case total production costs (capital, O&M, and fuel) using the revised section 316(b) specifications are higher by 0.4% and 0.1% in the years 2010 and 2020, respectively.
- Early retirements of base case oil and gas steam capacity under the section 316(b) specifications increased by 390 MW. Early retirements of base case nuclear capacity decreased by 429 MW. There is no difference in the early retirement of coal capacity.
- The change in model specifications results in virtually no change in base case coal and gas fuel use.

B3-2.3 Model Inputs

Compliance costs and compliance-related capacity reductions are the primary model inputs in the analysis of section 316(b) regulations. EPA determined compliance costs for each of the 530 facilities subject to the proposed rule and modeled by the IPM.[7] For each facility, compliance costs consist of capital costs (including new wet tower capital costs, intake piping modification capital costs, and condenser upgrade costs for facilities costed with flow reduction technologies), fixed O&M costs, variable O&M costs, and permitting costs (for information on the costing methodology, see the § 316(b) Technical Development Document).[8]

Capital cost inputs into the IPM are expressed in terms of dollars per KW of capacity. The capital costs of compliance reflect the up-front cost of construction, equipment, and capital associated with the installation of required compliance technologies. While IPM uses a single up-front cost as a model input, the model translates this cost into a series of annual payments using a discount rate of 5.34 percent and a capital charge rate of 12 percent for the duration of the book life of the investment (assumed to be 30 years) or the years remaining in the modeling horizon, whichever is shorter.[9] The net present value of this stream of annual capital payments is the model input included as part of the objective function for which the model seeks the least cost solution.

Fixed O&M cost inputs into the IPM are expressed in terms of dollars per KW of capacity per year. ***Variable O&M cost*** inputs are expressed in dollars per MWh of generation.

Capacity reductions consist of an energy penalty and a one-time generator down-time and, for purposes of this analysis, were only applied to facilities costed with flow reduction technologies. ***Energy penalty*** estimates reflect the long-term reduction in capacity due to the on-going operation of compliance technologies and are expressed in terms of a percentage change in capacity. The energy penalty consists of two components: (1) a reduction in unit efficiency due to increased turbine back-pressure and (2) an increase in auxiliary power requirements to operate the cooling tower (e.g., for pumping and fanning). As discussed in *Chapter B1: Summary of Compliance Costs*, EPA's estimate of O&M compliance costs already includes the auxiliary power requirement component of the energy penalty. However, to fully capture the effect of the energy penalty in the market model analysis, the both components of energy penalty needed to be applied. To avoid double-counting of the auxiliary power requirements, EPA reduced the O&M compliance cost input into the IPM by the estimated value of the auxiliary power penalty, using the valuation methodology described in Chapter B1. ***Generator down-time*** estimates reflect the amount of time generators are off-line while compliance technologies are constructed and/or installed and are expressed in weeks. In contrast to the energy penalty, the generator down-time is a one-time event that occurs during the year when a facility complies with the policy option (for a discussion of how EPA estimated compliance years, see *Chapter B1: Summary of Compliance Costs*). Capacity reductions were only assigned to facilities costed with flow reduction technologies. Therefore, no facilities experience a capacity reduction (energy penalty or one-time shut down) under the proposed rule.

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[7] Of the 539 surveyed facilities subject to the section 316(b) Phase II Rule, nine are not modeled in the IPM. Three facilities are in Hawaii, one is in Alaska. Neither state is represented in the IPM. One facility is identified as an "Unspecified Resource" and does not report on any EIA forms. Four facilities are on-site facilities that do not provide electricity to the grid. The 530 in-scope facilities modeled by the IPM were weighted to account for facilities not sampled and facilities that did not respond to the EPA's industry survey and thus represent a total of 540 facilities industry-wide. The results for Phase II facilities in the remainder of this chapter, except where noted, are based on the 540 weighted facilities.

[8] No facilities under the proposed rule were costed with flow reduction technologies. However, 51 facilities were costed with flow reduction technology under the "Closed-loop, Recirculating Wet Cooling based on Waterbody type and Intake Capacity" Option (waterbody/capacity-based option) and 417 facilities were costed with flow reduction technology under the "Closed-loop, Recirculating Wet Cooling Everywhere" Option (all cooling towers option) (see discussion in *Chapter B7: Alternative Regulatory Options*).

[9] The capital charge rate is a function of capital structure (debt/equity shares of an investment), pre-tax debt rate (or interest cost), debt life, post-tax return on equity, corporate income tax, depreciation schedule, book life of the investment, and other costs including property tax and insurance. The discount rate is a function of capital structure, pre-tax debt rate, and post-tax return on equity.

The IPM operates at the boiler level. It was therefore necessary to distribute facility-level costs across affected boilers. EPA used the following methodology:

- Steam electric generators operating at each of the 530 modeled section 316(b) facilities were identified using data from Forms EIA-860A and 860B (1998 and 1999).
- Generator-specific design intake flows were obtained from Form EIA-767 (1998).[10]
- Facility-level compliance costs were distributed across each facility's steam generators. For facilities with available intake flow data, this distribution was based on each generator's proportion of total design intake volume; for facilities without available intake flow, this distribution was based on each generator's proportion of total steam electric capacity.
- Generator-level compliance costs were aggregated to the boiler level based on the EPA's Base Case 2000 cross-walk between boilers and generators.

B3-2.4 Model Outputs

The IPM generates a series of outputs on different levels of aggregation (boiler, model plant, region, and nation). The economic analysis for the Phase II Rule used a subset of the available IPM output. For each model run (base case and each analyzed policy option) and for each model run year (2008, 2010, 2013, and 2020) the following model outputs were generated:

- ***Capacity*** – Capacity is a measure of the ability to generate electricity. This output measure reflects the summer net dependable capacity of all generating units at the plant. The model differentiates between existing capacity, new capacity additions, and existing capacity that has been repowered.[11]

- ***Generation*** – The amount of electricity produced by each plant that is available for dispatch to the transmission grid ("net generation")..

- ***Energy Revenue*** – Revenues from the sale of electricity to the grid.

- ***Capacity Revenue*** – Revenues received by facilities operating in hours where the price of energy exceeds the variable production costs of generation for the next unit to be dispatched at that price in order to maintain reliable energy supply in the short run. At these peak hours, the price of energy includes a premium which reflects the cost of the required reserve margin and serves to stimulate investment in the additional capacity required to maintain a long run equilibrium in the supply and demand for capacity.

- ***Fuel Costs*** – The cost of fuel consumed in the generation of electricity.

- ***Variable Operation and Maintenance Costs*** – Non-fuel O&M costs that vary with the level of generation, e.g., cost of consumables, including water, lubricants, and electricity.

- ***Fixed Operation and Maintenance Costs*** – O&M costs that do not vary with the level of generation, e.g., labor costs and capital expenditures for maintenance.

- ***Capital Costs*** – The cost of construction, equipment, and capital. In the base case, capital costs at existing facilities are associated with investment in new equipment, e.g., the replacement of a boiler or condenser, or the repowering of the plant. In the post-compliance cases, this cost includes retrofitting existing plants with compliance technologies to meet the requirements of the proposed rule and the alternative regulatory options.

- ***Energy Price*** – The average annual price received for the sale of electricity.

- ***Capacity Price*** – The premium over energy prices received by facilities operating in peak hours during which system load approaches available capacity. The capacity price is the premium required to stimulate new market

[10] This information is provided in Schedule IV - Generator Information, Question 3.A (Design flow rate for the condenser at 100% load). Design intake flow data at the generator level is not available for nonutilities nor for those utility owned plants with a steam generating capacity less than 100MW. Generator-level design intake flow data were not available for 50 of the 530 modeled facilities.

[11] Repowering in the IPM consists of converting of oil/gas capacity to combined-cycle capacity.

entrants to construct additional capacity, cover costs, and earn a return on their investment. This price manifests as short term price spikes during peak hours and, in long-run equilibrium, need be only so large as is required to justify investment in new capacity.

- ***Early Retirements*** – The IPM models two types of plant closures: closures of nuclear plants as a result of license expiration and economic closures as a result of negative net present value of future operation.[12] This analysis only considers economic closures in assessing the impacts of the proposed rule and other regulatory options. However, cases where a nuclear facility decides to renew its license in the base case but does not renew its license in the post-compliance case for a given policy option are also considered economic closures and an impact of that policy option.

B3-3 Economic Impact Analysis Methodology

The IPM was used to identify changes to economic and operational characteristics such as capacity, generation, revenue, cost of generation, and electricity prices associated with the proposed Phase II Rule and alternative regulatory options. EPA identified changes resulting from each policy option by comparing it to the base case (i.e., the model run in the absence of section 316(b) Phase II regulations).[13] The outputs presented in the previous section were used to estimate the economic impacts of each regulatory option. EPA developed impact measures at two analytic levels: (1) the market as a whole and (2) the subset of in-scope Phase II facilities. Both analyses were conducted by NERC region. In both cases, the impacts of each option are defined as the difference between the model output for the base case scenario and the post-compliance scenario. The following subsections describe the impact measures used for the two levels of analysis.

B3-3.1 Market-level Impact Measures

The market-level analysis evaluates regional changes as a result of the proposed rule and the alternative regulatory options. Seven main measures are analyzed:

- ***(1) Changes in available capacity:*** This measure analyzes changes in the capacity available to generate electricity. A long-term reduction in availability may be the result of the energy penalty associated with the installation of recirculating systems, and of partial or full closures of plants subject to the rule. In the short term, temporary plant shut-downs for the installation of cooling towers may lead to reductions in available capacity. When analyzing changes in available capacity, EPA distinguished between existing capacity, new capacity additions, and repowering additions.

- ***(2) Changes in generation:*** This measure considers the amount of electricity generated. At a regional level, long-term changes in generation may be the result of plant closures, energy penalties, or a change in the amount of electricity traded between regions. In the short term, temporary plant shut-downs to install recirculating systems may lead to reductions in generation. At the national level, the demand for electricity does not change between the base case and the analyzed policy options (generation within the regions is allowed to vary). However, demand for electricity does vary across the modeling horizon according to the model's underlying electricity demand growth assumptions.

- ***(3) Changes in revenues:*** This measure considers the revenues realized by all facilities in the market. A change in revenues could be the result of a change in generation and/or the price of electricity.

- ***(4) Changes in variable production costs:*** This measure considers the regional change in average variable production cost per MWh. Variable production costs include fuel costs and other variable O&M costs but exclude

[12] Nuclear plants are evaluated for economic viability at the end of their license term. Nuclear units that, at age 30, did not make a major maintenance investment, are provided with a 10-year life extension, if they are economically viable. These same units may subsequently undertake a 20-year re-licensing option at age 40. Nuclear units that already had made a maintenance investment are provided with a 20-year re-licensing option at age 40, if they are economically viable. All nuclear units are ultimately retired at age 60.

[13] EPA conducted model runs based on different electricity demand assumptions: (1) a case using EPA's electricity demand assumptions and (2) a case using Annual Energy Outlook (AEO) electricity demand assumptions. The analyses presented in this chapter are based on EPA's electricity demand assumptions. The appendix to *Chapter B7: Alternative Regulatory Options* presents a discussion of the two different assumptions, the results of one alternative regulatory option using the AEO electricity demand assumptions, and a comparison of the differences in results between the AEO assumptions and the EPA assumptions.

fixed O&M costs and capital costs. Production cost per MWh is a primary determinant of how often a power plant's units are dispatched.

- ***(5) Changes in fuel costs:*** This measure considers a subset of the production costs included in the previous measure: fuel costs. Fuel costs generally account for the single largest share of production costs.

- ***(6) Changes in the price of electricity:*** This measure considers changes in regional prices as a result of the proposed rule. In the long term, electricity prices may change as a result of increased production costs of the Phase II facilities. In the short-term, price increases may be higher if large power plants have to temporarily shut down to construct and/or install recirculating systems. This analysis considers changes in both energy prices and capacity prices.

- ***(7) Plant closures:*** Only plants that are projected to remain operational in the base case but are closures in the post-compliance case are considered a closure as the result of the rule. An option may result in partial (i.e., unit) or full plant closures. An option may also result in avoided closures if a facility's compliance costs are low relative to other affected facilities. An avoided closure is a facility that would close in the base case but operates in the post-compliance case. At the market-level, the closure analysis considers the amount of capacity retired early, but not the number of retired facilities.

B3-3.2 Facility-level Impact Measures (In-scope Facilities Only)

EPA used the IPM results to analyze impacts on Phase II facilities at two levels: (1) potential changes in the economic and operational characteristics of the group of Phase II facilities and (2) potential changes to individual facilities within the group of Phase II facilities.

a. Group of Phase II facilities

The analysis of the group of Phase II facilities is largely similar to the market-level analysis described in Section B3-3.1 above, except that the base case and policy option totals only include the economic activities of the steam-electric generating units of the 540 in-scope Phase II facilities represented by the model. In addition, a few measures differ: (1) new capacity additions and prices are not relevant at the facility level, (2) repowering changes were not explicitly analyzed at the facility level, and (3) an additional measure, facilities that are not dispatched, is analyzed in this section but was not relevant at the market level. The following are the measures evaluated for the group of Phase II facilities:

- ***(1) Changes in available capacity:*** This measure considers the capacity available at the 540 Phase II facilities. A long-term reduction in availability may be the result of the energy penalty associated with the installation of recirculating systems, and of partial or full closures of plants subject to the rule. In the short term, temporary plant shut-downs for the installation of cooling towers may lead to reductions in available capacity.

- ***(2) Changes in generation:*** This measure considers the generation at the 540 Phase II facilities. Long-term changes in generation may be the result of plant closures, energy penalties, or a less frequent dispatch of a plant due to higher production cost as a result of the policy option. In the short term, temporary plant shut-downs may lead to reductions in generation at some of the 540 Phase II facilities. For some Phase II facilities, the proposed rule may lead to an increase in generation if their compliance costs are low relative to other affected facilities.

- ***(3) Changes in revenues:*** This measure considers the revenues realized by the 540 Phase II facilities. A change in revenues could be the result of a change in generation and/or the price of electricity. For some modeled 316(b) facilities, the proposed rule may lead to an increase in revenues if their generation increases as a result of the rule, or if the rule leads to an increase in electricity prices.

- ***(4) Changes in variable production costs:*** This measure considers the plant-level change in the average annual variable production cost per MWh. Variable production costs include fuel costs and other variable O&M costs but exclude fixed O&M costs and capital costs.

- ***(5) Changes in fuel costs:*** This measure considers a subset of the production costs included in the previous measure: fuel costs. Fuel costs generally account for the single largest share of production costs.

- ***(6) Plant closures:*** Only plants that are projected to remain operational in the base case but are closures in the post-compliance case are considered a closure as the result of the rule. An option may result in partial (i.e., unit) or full plant closures. An option may also result in avoided closures if a facility's compliance costs are low relative to other

affected facilities. An avoided closure is a facility that would close in the base case but operate in the post-compliance case. At the facility-level, both the number of closure facilities and their capacity are analyzed.

- ***(7) Non-dispatch facilities:*** This measures identifies Phase II facilities that do not generate electricity but are earning capacity revenues. These are facilities that do not retire but are also not dispatched. These facilities provide a portion of the spinning reserves necessary for system reliability. An increase in production costs may lead additional facilities to become non-dispatch facilities. Conversely, compliance costs that are relatively lower than those of other competing facilities may cause a non-dispatch facility in the base case to be dispatched under a policy option.

b. Individual Phase II facilities

To assess potential distributional impacts among individual Phase II facilities, EPA analyzed facility-specific changes to a number of key measures. For each measure, EPA determined the number of Phase II facilities that experience an increase or a reduction, respectively, within two ranges: 0 to 1 percent, and 1 percent or more.[14] EPA conducted this analysis for the following measures:

- ***(1) Changes in capacity utilization:*** Capacity utilization is defined as a unit's actual generation divided by its potential generation, if it ran 100 percent of the time (i.e., generation / (capacity * 365 days * 24 hours)). This measure indicates how frequently a unit is dispatched and earns energy revenues for its owner.

- ***(2) Changes in generation:*** See explanation in subsection a. above.

- ***(3) Changes in revenues:*** See explanation in subsection a. above.

- ***(4) Changes in variable production costs:*** See explanation in subsection a. above.

- ***(5) Changes in fuel costs:*** See explanation in subsection a. above.

- ***(6) Changes in operating income:*** Operating income is defined as revenues minus production cost. Operating income is an indicator of profitability and represents the amount of money available to cover the firm's non-production costs. Operating income of Phase II facilities may decrease as a result of reductions in revenues and/or increases in production costs.

B3-4 Analysis Results for the Proposed Rule

EPA was not able to execute the market model analysis with an analytic option that completely matches the proposed rule's specifications. Due to the lead time required to run an integrated electricity market model, EPA first completed an electricity market model analysis of two options with costs higher than those of the proposed option: (1) the waterbody/capacity-based option and (2) the all cooling towers option (the results of these two options are presented in *Chapter B7: Alternative Regulatory Options*). Both of the analyzed options are more stringent in aggregate than the proposed rule and provide a ceiling on the proposed rule's potential economic impacts. Because of limited time after the final definition of the proposed rule, EPA was unable to rerun the IPM model. As a result, EPA adopted a two-step approach for the analysis of potential impacts from the proposed Phase II Rule that uses the model outputs from the waterbody/capacity-based option:

- First, EPA identified that for certain regional electricity markets that do not have any facilities costed with a closed-cycle recirculating cooling water system, the waterbody/capacity-based option, as analyzed, matches the technology compliance requirements of the proposed rule.[15] These are the North American Electric Reliability Council (NERC) regions that do not border oceans and estuaries: ECAR, MAIN, MAPP, SPP. Accordingly, EPA was able to

[14] For the two alternative options analyzed in *Chapter B7: Alternative Regulatory Options*, EPA used three ranges: 0 to 1 percent, 1 to 3 percent, and 3 percent or more.

[15] While the compliance requirements are identical under the proposed rule and the alternative waterbody/capacity-based option, permitting costs associated with the proposed rule are higher than those for the alternative option analyzed using the IPM. The cost differential averages approximately 30 percent of total compliance costs associated with the alternative option. Despite the higher permitting costs, EPA concludes that the results of the alternative analysis are representative of impacts that could be expected under the proposed rule.

interpret the results of the IPM analysis for the waterbody/capacity-based option for these four NERC regions as representative of the proposed rule in these regions.

- Second, EPA determined that while the waterbody/capacity-based option, as analyzed in the IPM, matches the technology specifications of the proposed rule for the four regions discussed above, this is not the case for the other six NERC regions: ERCOT, FRCC, MAAC, NPCC, SERC, and WSCC. Under the waterbody/capacity-based option, some facilities in these regions were costed with more stringent and costly compliance requirements, including recirculating wet cooling towers, than would be required by the proposed rule. As a result, the IPM waterbody/capacity-based option overstates the impacts of the expected rule in these remaining six regions. To provide an alternative approach to estimating the rule's impacts in these regions, EPA compared the four NERC regions explicitly analyzed in the IPM analysis and the other six NERC regions in terms of characteristics relevant to the determination of the rule's impacts. EPA found no material differences between the two groups of regions in (1) the percentage of total base case capacity subject to the proposed rule, (2) the average annualized compliance costs of the proposed rule per MWh of generation, and (3) the distribution of compliance requirements of the proposed rule (see Table B3-4 below). EPA therefore concludes that the results for the four regions would be representative of the other NERC regions as well.

Table B3-4: Comparison of Compliance Requirements by NERC Region - 2008

NERC Region	Percent of Total Capacity Subject to the Rule	Total Annualized Compliance Cost per MWh Generation ($2001)	Percentage of In -Scope Facilities Subject to Each Compliance Requirement				
			Number of Phase II Facilities	Fine Mesh Traveling Screen w/ Fish Handling	Fine-Mesh Traveling Screen	Fish Handling and Return System	None
Four Analyzed NERC Regions							
ECAR	66.5%	$0.05	99	32.4%	7.1%	23.9%	36.6%
MAIN	60.9%	$0.04	49	30.6%	6.1%	22.7%	40.7%
MAPP	42.1%	$0.04	42	9.5%	7.1%	28.5%	54.8%
SPP	40.7%	$0.03	32	12.6%	0.0%	46.9%	40.5%
Average	**57.1%**	**$0.04**		**24.8%**	**5.8%**	**27.8%**	**41.5%**
Other Six NERC Regions							
ERCOT	57.8%	$0.04	51	2.0%	11.8%	60.8%	25.5%
FRCC	49.8%	$0.07	30	40.0%	13.3%	16.7%	30.0%
MAAC	50.7%	$0.06	43	26.2%	19.1%	28.8%	25.9%
NPCC	49.6%	$0.08	54	22.1%	34.2%	16.5%	27.1%
SERC	53.8%	$0.03	95	16.8%	7.4%	31.6%	44.2%
WSCC	18.3%	$0.02	33	52.9%	3.0%	16.6%	27.5%
Average	**43.6%**	**$0.04**		**22.8%**	**14.6%**	**30.3%**	**32.3%**
Average of All NERC Regions	**47.7%**	**$0.04**		**23.6%**	**10.9%**	**29.3%**	**0.3619367**

Source: U.S. EPA, 2000; U.S. EPA analysis, 2002.

Table B3-4 indicates that, on average, the ***percentage of capacity subject to the proposed rule*** is slightly higher in the four analyzed NERC regions compared to the other six regions. Everything else being equal, the higher the percentage of capacity subject to the rule, the greater the likelihood that the rule would affect production costs and electricity prices at a regional level. In addition, the ***average annualized compliance costs per MWh of generation*** for the four NERC regions, 4 cents per MWh, is identical to that of the other six NERC regions. Again, everything else being equal, the higher the compliance cost per MWh, the greater the likelihood that the rule would affect production costs and electricity prices at a regional level. Finally, the ***distribution of compliance requirements*** is similar for the two groups of regions. The four analyzed regions have

a slightly higher percentage of in-scope facilities costed with the most costly compliance technology, fine mesh traveling screens with fish handling systems, than the other six regions. Conversely, the six regions have a higher percentage of facilities costed with fine mesh screens, the second most costly compliance technology. The six regions also have a lower percentage of facilities that are costed with no compliance technologies. Everything else being equal, the more facilities costed with costly compliance technology, the higher the impacts that could be expected for Phase II facilities as a group and for individual Phase II facilities.

Based on this comparison and the limited amount of electricity exchanges between regions modeled in IPM,[16] EPA concluded that the analysis of impacts under the proposed rule for the four NERC regions is representative of likely impacts in the other six NERC regions.

The remainder of this section presents the results of the economic impact analysis of the proposed rule for the four NERC regions for which the technology requirements under the waterbody/capacity-based option are identical to those of the proposed rule: ECAR, MAIN, MAPP, SPP. The analysis is based on IPM output for the base case and proposed rule for model run year 2008. Results are presented at the market level and the Phase II facility level.

B3-4.1 Market Analysis

This section presents the results of the IPM analysis for all facilities modeled by the IPM. The results in this section include facilities that are in-scope and facilities that are out-of-scope of the proposed Phase II Rule. As stated above, EPA concluded that results for the four NERC regions presented below are representative of likely impacts in the other six NERC regions.

Table B3-5 presents the market-level impact measures discussed in section B3-3.1 above: (1) Capacity changes, (2) generation changes, (3) revenue changes, (4) variable production cost changes, (5) fuel cost changes, (6) electricity price changes, and (7) plant closures. For each measure, the table presents the results for the base case and the proposed rule, the absolute difference between the two cases, and the percentage difference.

Table B3-5: Market Level Impacts of the Proposed Rule (Four NERC Regions; 2008)

Economic Measures[a]	Base Case	Proposed Rule	Difference	% Change
East Central Area Reliability Coordination Agreement (ECAR)				
(1) Total Domestic Capacity (MW)	118,390	118,570	180	0.2%
(1a) Existing	110,080	110,080	0	0.0%
(1b) New Additions	8,310	8,490	180	2.2%
(1c) Repowering Additions	0	0	0	0.0%
(2) Total Generation (GWh)	649,140	649,140	0	0.0%
(3) Total Revenues (Million, $2001)	$23,830	$23,850	$20	0.1%
(4) Variable Production Costs ($2001/MWh)	$12.53	$12.53	$0.00	0.0%
(5) Fuel Costs ($2001/MWh)	$10.11	$10.11	$0.00	0.0%
(6a) Energy Prices ($2001/MWh)	$22.58	$22.56	($0.02)	-0.1%
(6b) Capacity Prices ($2001/KW/yr)	$77.67	$77.86	$0.19	0.2%
(7) Closures – Capacity	0	0	0	0.0%

[16] Significant amounts of electricity exchanged between regions could limit the findings from the NERC region comparison, because the four analyzed regions may have benefitted from the higher compliance costs of the other six regions in the analyzed regulatory alternative. However, base case transmission from the four analyzed regions to the other six regions range from 3.5 to 6.7 percent of total generation, while transmission from the other six regions to the four analyzed ones ranges from 0 to 0.2 percent. In the post-compliance case, the change in transmissions of all regions is 0.2 percent or less.

Table B3-5: Market Level Impacts of the Proposed Rule (Four NERC Regions; 2008)

Economic Measures[a]	Base Case	Proposed Rule	Difference	% Change
Mid-America Interconnected Network (MAIN)				
(1) Total Domestic Capacity (MW)	60,230	60,210	-20	0.0%
(1a) Existing	53,690	53,680	-10	0.0%
(1b) New Additions	6,540	6,530	-10	-0.2%
(1c) Repowering Additions	0	0	0	0.0%
(2) Total Generation (GWh)	284,920	284,860	-60	0.0%
(3) Total Revenues (Million, $2001)	$11,120	$11,120	$0	0.0%
(4) Variable Production Costs ($2001/MWh)	$12.29	$12.29	$0.00	0.0%
(5) Fuel Costs ($2001/MWh)	$10.25	$10.25	$0.00	0.0%
(6a) Energy Prices ($2001/MWh)	$22.54	$22.55	$0.01	0.0%
(6b) Capacity Prices ($2001/KW/yr)	$78.15	$78.18	$0.02	0.0%
(7) Closures – Capacity	0	0	0	0.0%
Mid-Continent Area Power Pool (MAPP)				
(1) Total Domestic Capacity (MW)	35,470	35,470	0	0.0%
(1a) Existing	32,710	32,710	0	0.0%
(1b) New Additions	2,760	2,760	0	0.0%
(1c) Repowering Additions	0	0	0	0.0%
(2) Total Generation (GWh)	179,110	179,170	60	0.0%
(3) Total Revenues (Million, $2001)	$6,710	$6,700	($10)	-0.1%
(4) Variable Production Costs ($2001/MWh)	$11.67	$11.68	$0.01	0.0%
(5) Fuel Costs ($2001/MWh)	$9.64	$9.65	$0.01	0.1%
(6a) Energy Prices ($2001/MWh)	$22.25	$22.20	($0.05)	-0.2%
(6b) Capacity Prices ($2001/KW/yr)	$77.79	$77.74	($0.05)	-0.1%
(7) Closures – Capacity	0	0	0	0.0%
Southwest Power Pool (SPP)				
(1) Total Domestic Capacity (MW)	49,110	49,110	0	0.0%
(1a) Existing	48,950	48,950	0	0.0%
(1b) New Additions	160	160	0	0.0%
(1c) Repowering Additions	0	0	0	0.0%
(2) Total Generation (GWh)	217,670	217,750	80	0.0%
(3) Total Revenues (Million, $2001)	$8,440	$8,440	$0	0.0%
(4) Variable Production Costs ($2001/MWh)	$14.43	$14.43	$0.01	0.1%
(5) Fuel Costs ($2001/MWh)	$12.52	$12.52	$0.01	0.1%
(6a) Energy Prices ($2001/MWh)	$25.00	$24.99	($0.01)	0.0%
(6b) Capacity Prices ($2001/KW/yr)	$61.24	$61.24	$0.00	0.0%
(7) Closures – Capacity	0	0	0	0.0%

[a] Total capacity, existing capacity, total generation, and total revenues have been rounded to nearest 10.

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

The results presented in Table B3-5 show that the proposed rule would not lead to significant changes in any of the analyzed economic measures in any of the four regions. This finding is not surprising as the requirements of the proposed Phase II Rule are very inexpensive compared to the overall production costs in the regions (Table B3-4 indicates that the average cost of compliance per MWh of generation for these four regions is $0.04 as compared to an average variable production cost of $12.73). ECAR is projected to install 180 MW, or 2.2 percent, more new capacity under the proposed rule. However, this additional capacity represents only 0.2 percent of total capacity in the region. All other measures in all other regions change by 0.2 percent or less as a result of the proposed rule, with a majority having zero change. Based on these results, EPA concludes that there would be no energy effects from the proposed Phase II Existing Facilities Rule in these regions.

B3-4.2 Analysis of Phase II Facilities

This section presents the results of the IPM analysis for the Phase II facilities that are modeled by the IPM. Of the 540 Phase II facilities, 226 are located in the four analyzed regions. Three of these 226 facilities are identified by the IPM as baseline closures (two are located in MAIN, one is located in MAPP) and are therefore not represented in these results. Except where noted, the results in this section therefore reflect the 223 non-closure Phase II facilities modeled by the IPM.

EPA used the IPM results to analyze two potential facility-level impacts of the proposed section 316(b) Phase II Rule: (1) potential changes in the economic and operational characteristics of the group of Phase II facilities and (2) potential changes to individual facilities within the group of Phase II facilities. It should be noted that the results of both analyses only include the steam electric components of the Phase II facilities and thus do not provide complete measures for in-scope facilities that also operate non-steam electric generation, which are not subject to this rule.

a. Group of Phase II facilities

The analysis of performed for the group of Phase II facilities is similar to the market level analysis described above but is limited to facilities subject to the requirements of the section 316(b) rule. Table B3-6 presents the impact measures for the group of Phase II facilities discussed in section B3-3.2 above: (1) Capacity changes, (2) generation changes, (3) revenue changes, (4) variable production cost changes, (5) fuel cost changes, (6) plant closures, and (7) non-dispatch facilities. For each measure, the table presents the results for the base case and the proposed rule, the absolute difference between the two cases, and the percentage difference.

Table B3-6: Impacts on the Phase II Facilities of the Proposed Rule (Four NERC Regions; 2008)

Economic Measures[a]	Base Case	Proposed Rule	Difference	% Change
East Central Area Reliability Coordination Agreement (ECAR)				
(1) Total Capacity (MW)	78,710	78,710	0.00	0.0%
(2) Total Generation (GWh)	515,020	515,030	10.00	0.0%
(3) Revenues (Million, $2001)	$17,650	$17,650	$0.00	0.0%
(4) Variable Production Costs ($2001/MWh)	$12.34	$12.34	$0.00	0.0%
(5) Fuel Costs ($2001/MWh)	$9.94	$9.94	$0.00	0.0%
(6a) Closures – Number of Facilities	0	0	0.00	0.0%
(6b) Closures – Capacity	0	0	0.00	0.0%
(7a) Non-Dispatched Facilities – Number	2	2	0.00	0.0%
(7b) Non-Dispatched Facilities – Capacity	191	191	0.00	0.0%

Table B3-6: Impacts on the Phase II Facilities of the Proposed Rule (Four NERC Regions; 2008)

Economic Measures[a]	Base Case	Proposed Rule	Difference	% Change
Mid-America Interconnected Network (MAIN)				
(1) Total Capacity (MW)	36,700	36,700	0.00	0.0%
(2) Total Generation (GWh)	226,360	226,350	-10.00	0.0%
(3) Revenues (Million, $2001)	$7,890	$7,890	$0.00	0.0%
(4) Variable Production Costs ($2001/MWh)	$11.74	$11.74	$0.00	0.0%
(5) Fuel Costs ($2001/MWh)	$9.55	$9.55	$0.00	0.0%
(6a) Closures – Number of Facilities	0	0	0.00	0.0%
(6b) Closures – Capacity	0	0	0.00	0.0%
(7a) Non-Dispatched Facilities – Number	2	2	0.00	0.0%
(7b) Non-Dispatched Facilities – Capacity	2,757	2,757	0.00	0.0%
Mid-Continent Area Power Pool (MAPP)				
(1) Total Capacity (MW)	14,920	14,920	0.00	0.0%
(2) Total Generation (GWh)	103,430	103,470	40.00	0.0%
(3) Revenues (Million, $2001)	$3,420	$3,420	$0.00	0.0%
(4) Variable Production Costs ($2001/MWh)	$11.78	$11.78	$0.00	0.0%
(5) Fuel Costs ($2001/MWh)	$9.84	$9.85	$0.00	0.0%
(6a) Closures – Number of Facilities	0	0	0.00	0.0%
(6b) Closures – Capacity	0	0	0.00	0.0%
(7a) Non-Dispatched Facilities – Number	6	6	0.00	0.0%
(7b) Non-Dispatched Facilities – Capacity	326	326	0.00	0.0%
Southwest Power Pool (SPP)				
(1) Total Capacity (MW)	19,990	19,990	0.00	0.0%
(2) Total Generation (GWh)	112,250	112,350	100.00	0.1%
(3) Revenues (Million, $2001)	$3,930	$3,930	$0.00	0.0%
(4) Variable Production Costs ($2001/MWh)	$13.32	$13.34	$0.01	0.1%
(5) Fuel Costs ($2001/MWh)	$11.07	$11.09	$0.01	0.1%
(6a) Closures – Number of Facilities	0	0	0.00	0.0%
(6b) Closures – Capacity	0	0	0.00	0.0%
(7a) Non-Dispatched Facilities – Number	8	8	0.00	0.0%
(7b) Non-Dispatched Facilities – Capacity	1,857	1,857	0.00	0.0%

[a] Total capacity, total generation, and revenues have been rounded to the closest 10.

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

The results presented in Table B3-6 show that the proposed rule would not lead to significant changes in the performance of the 223 Phase II facilities as evaluated by the seven measures. The rule would cause no early plant closures and would not increase the number of Phase II facilities that are not dispatched. In all analyzed NERC regions, except for SPP, none of the measures experiences any change as a result of the rule. In SPP, generation, variable productions costs, and fuel costs change minimally, 0.1 percent.

b. Individual Phase II facilities

The analysis in the previous section showed that the group of Phase II facilities as a whole would not experience economic impacts under the proposed rule. However, it is possible that there would be shifts in economic performance among individual facilities subject to this rule. To examine the range of possible impacts to individual Phase II facilities, EPA analyzed facility-specific changes in (1) capacity utilization, (2) generation, (3) revenues, (4) variable production costs, (5) fuel costs, and (6) operating income. Table B3-7 presents the 223 Phase II facilities located in the four analyzed NERC regions by category of change for each economic measure.

Table B3-7: Number of Individual Phase II Facilities with Operational Changes (Four NERC Regions; 2008)

Economic Measures[a]	Reduction		Increase		No Change
	0-1%	> 1%	0-1%	> 1%	
(1) Change in Capacity Utilization	2	0	2	1	218
(2) Change in Generation	2	0	1	2	218
(3) Change in Revenues	56	0	44	2	121
(4) Change in Variable Production Costs	0	0	27	0	178
(5) Change in Fuel Costs	2	0	43	2	158
(6) Change in Operating Income	66	0	58	1	98

[a] For all measures, the percentages used to assign facilities to impact categories have been rounded to the nearest 10th of a percent.

[b] Of the 223 Phase II facilities located in the four NERC regions, 18 facilities had zero generation and zero fuel costs in either the base case or post-compliance scenario. It was therefore not possible to calculate the change in variable production costs or the change in fuel costs per MWh for these facilities. As a result, the number of facilities adds up to 205 instead of 223 for these two measures.

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B3-7 shows that most of the Phase II facilities in the four analyzed NERC regions experience very little changes in economic activity as a result of this rule. No facility experiences a decrease in generation, capacity utilization, revenues, or operating income, or an increase in production costs of more than one percent. These findings, together with the findings from the comparison of compliance costs and requirements across all regions above, further confirm EPA's conclusion that the proposed rule would not result in economic impacts to Phase II facilities located in the four analyzed NERC regions.

B3-5 Summary of Findings

Based on the results presented in sections B3-4.1 and B3-4.2, EPA concludes the proposed rule will have little or no impact on the electricity markets in any of the four analyzed regions, the group of Phase II facilities, or individual Phase II facilities. The analyses at the market and the Phase II facility level have shown that the rule would lead to no significant changes in any of the economic measures examined by EPA.

Given EPA's earlier noted finding of no material differences in important characteristics relevant to rule impacts between the four analyzed NERC regions and the other six NERC regions, EPA concludes that the finding of no significant impact for these four regions could be extended to the remaining six regions. As a result, EPA concludes that the proposed rule will not pose significant impacts in any NERC region.

B3-6 Uncertainties and Limitations

There are uncertainties associated with EPA's analysis of the electric power market and the economic impacts of the proposed Phase II Rule and alternative regulatory options. These uncertainties stem from two main issues: (1) the specification of the policy options analyzed by the IPM and (2) modeling limitations of the IPM.

Specification of policy options: Due to limited time after the final definition of the proposed option, EPA was not able to use the IPM to analyze a regulatory option that completely matches the proposed rule's specifications. Rather, EPA employed a methodology that used the results of a previously completed analysis of the waterbody/capacity-based option, an option with more costly and stringent compliance requirements, to assess the impacts of the proposed rule. The following limitations result from the use of these results to represent the impacts associated with the proposed rule:

- *Extrapolation of results from four regions to the national level:* EPA identified four regional electricity markets (NERC regions) for which the compliance technology requirements under the waterbody/capacity-based option match those of the proposed rule. EPA assumed that the results of the IPM analysis of the more stringent option are representative of the proposed rule in these regions. The six NERC regions for which the compliance technology requirements under the proposed rule are different from the waterbody/capacity-based option were subsequently compared to the four NERC regions with regard to characteristics relevant to the determination of impacts. This comparison revealed no material differences between the two groups of regions. Based on this comparison, EPA concluded that the results for the four regions would be representative of potential impacts for all regions. While EPA recognizes that using the results from four regional markets to represent national impacts introduces some uncertainty, EPA believes this approach to be reasonable given the similarities revealed by the comparison of NERC regions.

- *Difference in permitting costs in four regional markets:* While the compliance technology requirements in the four analyzed NERC regions are identical under the proposed rule and the waterbody/capacity-based option, permitting costs associated with the proposed rule are higher than those for the alternative option. The cost differential averages approximately 30 percent of total compliance costs associated with the alternative option. As a result, EPA's analysis may underestimate facility and market level impacts associated with the proposed rule. However, given the very low absolute costs of the proposed rule, EPA concludes that the results of the alternative analysis are representative of impacts that could be expected under the proposed rule.

Modeling limitations of the IPM: Additional uncertainty is introduced by the IPM modeling framework. Specifically, the IPM assumes that demand at the national level and imports from Canada and Mexico would not change between the base case and the analyzed policy options (generation within the regions is allowed to vary). Under the EPA Base Case 2000 specification, the ***demand for electricity*** is based on the AEO 2001 forecast adjusted to account for demand reductions resulting from implementation of the Climate Change Action Plan (CCAP). The IPM model, as specified for this analysis, does not capture changes in demand that may result from electricity price increases associated with the proposed rule and alternative regulatory options. While this constraint may overestimate total demand in policy options that have high compliance cost and that may therefore lead to significant price increases, EPA believes that it does not affect the results analyzed in support of the proposed rule. As described in Section B3-4 above, the price increases associated with the proposed rule are minimal. EPA therefore concludes that the assumption of inelastic demand-responses to changes in prices is reasonable. In addition, all things being equal, holding generation fixed would result in conservative estimates of production costs and electricity prices because more costly facilities remain economically viable longer to serve load that does not decrease in response to higher prices. Similarly, holding ***international imports*** fixed would provide a conservative estimate of production costs and electricity prices, because imports are not subject to the rule and may therefore become more competitive relative to domestic capacity, displacing some of the more expensive domestic generating units. However, EPA concludes that fixed imports do not materially affect the results of the analyses. Only four of the ten NERC regions import electricity (ECAR, MAPP, NPCC, and WSCC) and the level of imports compared to domestic generation in each of these regions is very small (0.03 percent in ECAR, 2.4 percent in MAPP, 5.6 percent in NPCC, and 1.5 in WSCC).

REFERENCES

U.S. Environmental Protection Agency (U.S. EPA). 2000. Section 316(b) Industry Survey. *Detailed Industry Questionnaire: Phase II Cooling Water Intake Structures* and *Industry Short Technical Questionnaire: Phase II Cooling Water Intake Structures*, January, 2000 (OMB Control Number 2040-0213). *Industry Screener Questionnaire: Phase I Cooling Water Intake Structures*, January, 1999 (OMB Control Number 2040-0203).

U.S. Environmental Protection Agency (U.S. EPA). 2002. *Documentation of EPA Modeling Applications (V.2.1) Using the Integrated Planning Model*. EPA 430/R-02-004. March 2002.

Appendix to Chapter B3

INTRODUCTION

This appendix presents additional, more detailed information on EPA's research to identify models suitable for analysis of environmental policies that affect the electric power industry. In addition, this appendix presents a comparison of the specifications of the EPA Base Case 2000 and its predecessor Base Case specifications.

CHAPTER CONTENTS

B3-A.1 SUMMARY COMPARISON OF ENERGY MARKET MODELS

EPA performed research to identify electricity market models that could potentially be used in the analysis of impacts associated with the proposed section 316(b) Phase II regulation and other regulatory options. This research included reviewing available forecast studies and interviewing persons knowledgeable in the area of electricity market forecasting. EPA focused on identifying models that are widely used for public policy analyses, peer reviewed, of national scope, and have the capabilities needed to perform regulatory impact scenario analyses of the type required for the section 316(b) Phase II economic analyses. Based on this research, EPA identified three models that were potentially suitable for the analysis of the proposed section 316(b) Phase II regulations:

- (1) The Department of Energy's National Energy Modeling System (NEMS),
- (2) The Department of Energy's The Policy Office Electricity Modeling System (POEMS), and
- (3) ICF Consulting's Integrated Planning Model (IPM®).

Each of these models was developed to meet the specific needs of different end users and therefore differ in terms of structure, inputs, outputs, and capability. Table B3-A-1 below presents a detailed comparison of the three models. The comparison comprises:

- ***General features,*** including a description of each model, their general applications, and their environmental applications.

- ***Modeling features,*** including each model's treatment of existing environmental regulations, of industry restructuring, and of economic plant retirements; their regional capabilities; their plant/unit detail and data sources; their general data inputs and outputs; and their data inputs and outputs required for the section 316(b) analysis.

- ***Logistical considerations,*** including each model's costs, computational requirements, accessability and response time; their documentation and issues regarding disclosure of inputs or results; and general notes and references.

Table B3-A-1: Comparison of Electricity Market Models

Model	DOE/EIA: NEMS	DOE/OP: POEMS (OnLocation, Inc.)	EPA/Office of Air Policy (OAP): IPM (ICF Consulting Inc.)
General Features			
Description	Modular structured model of national energy supply and demand, includes macroeconomic, international, supply and demand modules, as well as an electricity market module (EMM) that can be run independently. The EMM represents generation, transmission and prices of electricity. Based on forecasts of fuel prices, variable O&M, and electricity demand, determines plant dispatch to ***achieve the least cost supply of electric power***.	POEMS is a model integration system that allows the substitution of the TRADELEC model for the EMM in NEMS. TRADELEC allows for a greater level of detail about the electricity sector than the EMM. Designed to examine the effect of market structure transformation of the electricity sector. It solves for the trade of the commodity as a function of relative prices, transmission constraints and cost of market entry by ***maximizing economic gains*** achieved through commodity trading.	A production cost model based on linear programming approach, solves for least cost dispatch. Simulates system dispatch and operations, estimates marginal generation costs on an hourly basis. ***Minimizes present worth of total system cost*** subject to various constraints.
General Applications	Used to produce annual forecasts of energy supply, demand, and prices through 2020 for the Annual Energy Outlook. Can also be used to analyze effects of proposed regulations. EIA performs studies for Congress, DOE, other agencies.	Used by DOE's policy office to study the impacts of electricity market transformation/ deregulation through 2010. Supports the administration's 1999 bill on industry deregulation, the Comprehensive Electricity Competition Act (CECA).	Primary model used by EPA Air Program offices to evaluate policy and regulatory impacts through 2030. EPA Office of Policy also used this model for GCC and retail deregulation analysis. Used by over 50 private sector clients to develop compliance plans, price forecasts, market analysis, and asset valuation.
Environmental Applications	Includes a Carbon Emission submodule. Can also calculate emissions. Produced "Analysis of Carbon Mitigation Cases" for EPA.	DOE application generally not designed to perform environmental regulatory analysis. Examines a renewable portfolio standard. EPA/ARD concluded that air emission estimates are low relative to IPM and other models. However, DOE contractor has performed analyses of environmental policies for private clients.	Analyzes environmental regulations by simultaneously selecting optimal compliance strategies for all generating units. Can calculate emissions, and simulate trading scenarios. Used for ozone (NO_x), SO_2, and mercury emissions control scenarios; implementation of NAAQS for ozone and PM; alternative NO_x emissions trading and rate-based programs for OTAG, CAAA Title IV NO_x Rule; NO_x control options; RIA for the NO_x SIP call; and GCC scenarios. Possible to accommodate other environmental regulations.

Table B3-A-1: Comparison of Electricity Market Models

Model	DOE/EIA: NEMS	DOE/OP: POEMS (OnLocation, Inc.)	EPA/Office of Air Policy (OAP): IPM (ICF Consulting Inc.)
Modeling Features			
Treatment of Environmental Regulations	Reference case represents all existing regulations and legislation in effect as of July 1, 1998, including impacts of the Climate Change Action Plan and the NO_x SIP call. EMM can analyze seasonal environmental controls to the extent that they match up with the seasonal representations in the model (non-sequential months are grouped according to similar load characteristics).	Assumes existing regulations and legislation remain in place and facilities comply with existing regulations in the least cost way. Most recent reference case analysis includes NO_x SIP call. Assesses a renewable portfolio in the competition case. Does not include other proposed or anticipated environmental regulatory scenarios in DOE analysis.	The base case includes current federal and state air quality requirements, including future implementation of SO_2 and NO_x requirements of Title IV of the CAA, the NO_x SIP call as implemented through a cap and trade program. Base case also includes assumptions regarding demand reductions associated with the Climate Change Action Plan.
Treatment of Restructuring	All regions assumed to have wholesale competition. Only states with enacted legislation are treated as competitive for retail markets in base case. Has a competitive pricing scenario that assumes full retail competition.	Designed to compare competitive wholesale and cost-of-service retail market structures to fully competitive market structure at the wholesale and retail levels. Compares prices and determines "stranded assets" at the firm level. Pricing modeled for 114 power control areas, assumes profit maximizing behavior.	EPA uses assumptions in IPM that reflect wholesale competition occurring throughout the electric power industry. Work for private clients uses different assumptions.
Treatment of Economic Plant Retirements	Uses assumptions about licencing and needs for new major capital expenses to forecast nuclear retirements. For fossil steam, model checks yearly to compare revenues at market price with future O&M and fuel costs to forecast economic retirements. Results appear to have second highest forecast of fossil steam retirements compared to other models.	Uses same method as NEMS for forecasting "forced" retirements of nuclear assets due to operating constraints such as licences. Economic retirements based on lack of ability to cover short term going forward costs and the cost of capacity replacement in the long term. Results appear to have highest forecast of fossil steam retirements compared to other models.	Uses assumptions about licencing in forecasting nuclear retirements. The IPM model retires capacity when unit level operating costs reach a level that total electric system costs are minimized by shutting down the existing unit.
Regional Capabilities	Model runs analysis for 15 supply regions.	Analyzes 114 power control areas connected by 680 transmission links.	Analyzes 26 supply regions that can be mapped to NERC regions.
Plant/Unit Detail	Groups all plants into 36 capacity types based on fuel type, burner technology, emission control technology, etc. within a region. Units or plants can be grouped differently according to §316(b) characteristics.	Units are grouped according to demand and supply regions, fuel type, prime mover, in-service period, similar heat rates. There are 6,000 unit groupings, an average of 55 per power control area. Plants can be re-grouped for §316(b).	Groups approximately 12,000 generating units into model plants. Grouped by region, state, technology, boiler configuration, location, fuel, heat rate, emission rate, pollution control, coal demand region. Plants can be re-grouped for §316(b).

Table B3-A-1: Comparison of Electricity Market Models

Model	DOE/EIA: NEMS	DOE/OP: POEMS (OnLocation, Inc.)	EPA/Office of Air Policy (OAP): IPM (ICF Consulting Inc.)
Modeling Features (cont.)			
Plant/Unit Data Sources	Form EIA-860A (all utility plants); Form EIA-867 (nonutility plants <1MW); Form EIA-767 (steam plants <10MW); Form EIA-759 (monthly operating data for utility plants).	Model includes "virtually all" currently existing generating units, including utility, exempt wholesale generators (EWGs), and cogenerators.	Over 12,000 generating units are represented in this model. Includes all utility units included in Form EIA-860 database. Plus IPPs and cogenerating units that sell firm power to the wholesale market. Also draws from other EIA Forms, Annual Energy Outlook (AEO), UDI, and other public and private databases. In addition, ICF has developed a database of industrial steam boilers with over 250 MMBtu/hr capacity in 22 eastern states.
General Data Inputs	Demand, financial data, tax assumptions, EIA and FERC data on capital costs, O&M costs, operating parameters, emission rates, existing facilities, new technologies, transmission constraints, and other inputs from other modules.	Inputs are similar to NEMS (for demand, fuel price and macroeconomic data), and EIA reports. FERC filings for other inputs such as capacity, operating costs, performance, transmission, imports, and financial parameters.	Some inputs are similar to NEMS, including demand forecast, and cost and performance of new and existing units. Emission constraints, repowering, and retrofit options are EPA specified. Fuel supply curves are used to model gas and coal prices.
Data Inputs for §316(b) EA	Would need to provide information on additional capital costs, O&M costs, study costs, outage period for technology installation, and changes in heat rate and plant energy use associated with ***each type of technology as it applies to each type of model plant***.	Would need to provide information on additional capital costs, O&M costs, outage period for installation, and changes in heat rate and plant energy use associated with ***each type of technology as it applies to each plant grouping***.	Would need to provide information on additional capital costs, O&M costs, outage period for installation, and changes in heat rate and plant energy use associated with ***each type of technology as it applies to each type of model plant***.
General Data Outputs	Retail price and price components, fuel demand, capital requirements, emissions, DSM options, capacity additions, and retirements by region and fuel type.	Dispatch, electricity trade, capacity expansion, retirements, emissions, and pricing (retail and wholesale) by region, state, and fuel type.	Regional and plant emissions; fuel, capital, and O&M costs; environmental retrofits; capacity builds; marginal energy costs; fuel supply, demand, and prices (primarily wholesale; one study focused on retail market).
Data Outputs for §316(b) EBA	Results would include additional economic retirements, changes in generation, and changes in revenues for ***each region and fuel type***. EMM cannot provide results on a state-by-state basis. By design, it is not possible to map model plant results back to specific plant/owner using current modeling approach.	Results would include additional economic retirements, changes in generation, and changes in revenues for ***each region and plant grouping***. Could map costs to units and owners with some modification of structure.	Results would include additional economic retirements, changes in generation, and changes in revenues for ***each region and model plant type***. Currently has ability to map back to specific unit and plant/owner. While this process is automated, it requires 2-3 days of manual checking for every year modeled.

Table B3-A-1: Comparison of Electricity Market Models

Model	DOE/EIA: NEMS	DOE/OP: POEMS (OnLocation, Inc.)	EPA/Office of Air Policy (OAP): IPM (ICF Consulting Inc.)
Logistical Considerations			
Costs *(cost estimates should be considered very preliminary)*	No out-of-pocket costs expected.	Initial policy case using existing scenario: $15-20k. Setting up new base case scenario, performing several runs, and producing briefing: $40-60k. (Assumes plant re-grouping cost is included in second estimate only.)	Initial policy case: $20-30k. Incremental cases $2-10k. Re-grouping model plants would be labor intensive and add costs to analysis.
Computational Requirements	Setting up a policy case may take two months. The model run time is two hours without iterating with rest of NEMS, four hours for total NEMS iteration. EIA runs NEMS on RS6000 workstations.	Setting up and running policy case could take from a few days to a few weeks, depending on whether policy case builds on an existing scenario and the complexity of the policy scenarios.	Depends on number of model plants and number of years in analysis. Base case approximately 4-6 hours.
Accessability and Response Time	Access and response time dependent on agreement between EIA and EPA and EIA's schedule. Could be difficult to get results turned around in time to meet regulatory schedule, depending on EIA's reporting schedule.	Access and response time potentially dependent on agreement between DOE and EPA and DOE's schedule. Model run by a contractor. ARD has impression that model has long set-up time, model not set up to perform many iterations quickly.	ICF is an EPA contractor. Assume that access and response time will be consistent with requirements of analysis.
Documentation and Disclosure of Inputs/Results	Documentation and results already available to public. Presented by year for fuel type and region. Could make aggregated results publicly available. EIA does not release plant-specific results.	Documentation and results of reference and competition cases are available to public on DOE's web page.	Documentation of the EPA Base Case already available to public. Assume disclosure would be similar to that for NO_x SIP call, etc. EPA/ARD states that there is more in public domain regarding IPM than most models.
Notes	The NEMS code and data are available to anyone for their own use. Anyone wishing to use NEMS is responsible for any code conversions or setup on their own systems. For example, FORTRAN compilers differ between the workstation and PC. Several national laboratories and consulting firms have used NEMS or portions of it, but the time investment is considerable. One out-of-pocket expense is the purchase of an Optimization Modeling Library (OML) license. OML is used to solve the embedded linear programs in NEMS. In order to modify or execute one of the NEMS modules that includes a linear program (EMM is one of them), an OML license is required.	DOE's contractor stated that they may need to make some structural changes to the modeling framework to accommodate the requirements for §316(b) analysis so that the model can incorporate the effects of the additional costs into the decision process (either to continue running a plant or to retire and replace the plant).	OAP sensitive to other EPA offices using another model or using IPM with different assumptions. Willing to coordinate and provide background and technical support. The EPA Base Case has received some challenges over impacts of Climate Change Action Plan on end-use demand. However, has cleared OMB review under other regulatory proposals.

Table B3-A-1: Comparison of Electricity Market Models

Model	DOE/EIA: NEMS	DOE/OP: POEMS (OnLocation, Inc.)	EPA/Office of Air Policy (OAP): IPM (ICF Consulting Inc.)
References	‣ Annual Energy Outlook 1999, Report#:DOE/EIA-0383(99); ‣ Assumptions to the AEO99, Report#:DOE/EIA-0554(99); ‣ EMM/NEMS Model Documentation Report, Report#: DOE/EIA-M0689(99); ‣ Personal communications with EIA staff: Jeffrey Jones (jeffrey.jones@eia.doe.gov) and Susan Holte (sholte@eia.doe.gov).	‣ POEMS Model Documentation, June 1998; ‣ Supporting Analysis for the Comprehensive Electricity Competition Act (CECA), May, 1999, Report#: DOE/PO-0059; ‣ The CECA: A Comparison of Model Results, September, 1999, Report#: SR/OAIF/99-04; ‣ Personal communications with DOE staff: John Conti (john.conti@hq.doe.gov), EPA staff: Sam Napolitano (napolitano.sam@epa.gov), and contractor: Lessly Goudarzi (goudarzi@onlocationinc.com).	‣ Analyzing Electric Power Generation Under the CAA (Appendix 2), March, 1998 (EPA/OAR/ARD); ‣ Analysis of Emission Reduction Options for the Electric Power Industry (Chapter 2), March, 1999 (EPA/OAR/ARD); ‣ IPM Demonstration, May, 1998 (slides by ICF); ‣ Personal communications with EPA staff: Sam Napolitano (napolitano.sam@epa.gov), and contractors: John Blaney (blaneyj@icfkaiser.com).

Source: U.S. EPA analysis, 2002.

B3-A.2 Differences Between the EPA Base Case 2000 and Previous Model Specifications

Past applications by EPA of the IPM model have employed a predecessor base case specification. The previous specification of the IPM model, EPA Base Case 1998, was recently updated to the current EPA Base Case 2000. The revised specification used for the section 316(b) analysis uses more complete and current cost and performance data for new and existing facilities, updated demand growth forecasts, and revised financial, fuel cost, and regulatory assumptions. The primary differences between the IPM's EPA Base Case 2000 and its predecessor model specification are identified and discussed below. For more a more detailed discussion of the specification of the EPA Base Case 2000 see *Documentation of EPA Modeling Applications (V.2.1) Using the Integrated Planning Model* (U.S. EPA, 2002).

- The National Electric Energy Data System (NEEDS), the database containing location, operational, and emission data for each of the existing and planned-committed generating units modeled in each IPM base case specification, was updated using 1998 EIA data taken primarily from Form EIA-860A, Form EIA-860B, Form EIA-759, and Form EIA-767. In addition, the update used data from the 1998 NERC Electric Supply and Demand database, second quarter values from EPA's 2000 Continuous Emission Monitoring System database, and the EPA 1999 Information Collection Request database.

- The EPA Base Case 1998 demand growth assumptions were updated for the EPA Base Case 2000 specification. The demand growth assumptions for the original specification were based on the 1997 NERC Electricity Supply and Demand forecast for Net Energy for Load in early years, and on the Data Research Institute (DRI) 1995 forecast for later years. These original forecasts were adjusted based on EPA's estimate of the demand reductions resulting from implementation of the Climate Change Action Plan (CCAP). The EPA Base Case 1998 electricity demand growth rate was 1.6 percent per year for 1997-2000, 1.8 percent per year for 2001-2010, and 1.3 percent per year for beyond 2010. EPA Base Case 2000 electricity demand growth is based on the AEO 2001 forecast. The AEO 2001 forecast was also adjusted to account for impacts of initiatives created under the CCAP in the revised base case specification. The EPA Base Case 2000 average annual growth rate in Net Energy for Load is 1.2 percent for 2000-2020.

- Fuel Price assumptions were also updated under the EPA Base Case 2000 specification. Revised fuel price forecasts/ supply curves for nuclear and biomass assumptions were taken from AEO2000 and AEO2001, respectively, and natural gas information was derived from ICF's Gas Systems Analysis Model (GSAM).

- The underlying assumptions affecting the retirement of fossil fired and nuclear capacity under the original specification were revised for EPA Base Case 2000. Fossil power plants are given no fixed retirement date in EPA Base Case 2000 as compared to EPA Base Case 1998 where they were assumed to have a finite lifetime. In the EPA

Base Case 2000 retirement is determined endogenously based on economics. In addition, the option of re-licensing nuclear units was introduced for EPA Base Case 2000, based on AEO2000 nuclear capacity factor forecast data. Nuclear units that had not made a major maintenance investment, at age 30, are provided with a 10-year life extension. These same units may subsequently undertake a 20-year re-licensing option at age 40. Nuclear units that already had made a maintenance investment are provided with a 20-year re-licensing option at age 40. All nuclear units are ultimately retired at age 60.

- The cost and performance characteristics of new and existing units as well as environmental control technologies such as SO_2 scrubbers, selective catalytic reduction, and activated carbon injection were updated using more recent data for the EPA Base Case 2000 specification. For example, the O&M costs for existing units were updated to include the cost of capital additions. Further, the cost and performance assumptions for new units were updated using information presented in AEO2000.

- The financial assumptions for environmental control options and new units were revised based on recent market activity. The capital charge rate and discount rate in EPA Base Case 1998 were 10.4% and 6%, respectively. For the EPA Base Case 2000 specification the capital charge rate and discount rate were revised to 12% and 5.34%, respectively, for retrofits; 12.9% and 6.14%, respectively, for new combined cycle units; and 13.4% and 6.74%, respectively, for new combustion turbine units.

- The EPA Base Case 2000 uses updated transmission assumptions. EPA Base Case 2000 organizes the United States into 26 different power market regions for analyzing inter-regional electricity transfers across the interconnected bulk power transmission grid as compared to 21 power market regions in EPA Base Case 1998. Assumptions regarding transmission capabilities in the EPA Base Case 2000 were updated based on more recent NERC documents.

- The EPA Base Case 2000 is updated to account for additional environmental regulations. Specifically, EPA Base Case 2000 accounts for EPA's NO_x SIP Call regulation, a trading program covering all fossil units in 19 northeastern states during the ozone season (May-September). In addition, state level environmental regulations in Texas, Missouri, and Connecticut are also modeled.

- The aggregation scheme for model plants was revised under EPA Base Case 2000. The group of coal fired model plants was further disaggregated based on power plant firing type, fine particulate controls, and post combustion NO_x controls.

Chapter B4: Regulatory Flexibility Analysis

Introduction

The Regulatory Flexibility Act (RFA) requires EPA to consider the economic impact a proposed rule would have on small entities. The RFA requires an agency to prepare a regulatory flexibility analysis for any notice-and-comment rule it promulgates, unless the Agency certifies that the rule "will not, if promulgated, have a significant economic impact on a substantial number of small entities" (The Regulatory Flexibility Act, 5 U.S.C. § 605(b)).

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For the purposes of assessing the impacts of the Proposed Section 316(b) Phase II Existing Facilities Rule on small entities, EPA has defined a small entity as: (1) a small business according to the Small Business Administration (SBA) size standards; (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; or (3) a small organization that is a not-for-profit enterprise that is independently owned and operated and is not dominant in its field. The SBA defines small businesses based on Standard Industrial Classification (SIC) codes and size standards expressed by the number of employees, annual receipts, or total electric output (13 CFR §121.20). The thresholds used in this analysis are four-digit SIC codes at the domestic parent entity-level.[1]

To evaluate the potential impact of this rule on small entities, EPA identified the domestic parent entity of each in-scope Phase II facility and determined its size. EPA used a "sales test" to evaluate the potential severity of economic impact on electric generators owned by small entities. The test calculates annualized post-tax compliance cost as a percentage of total sales revenues and uses a threshold of three percent to identify facilities that would be significantly impacted as a result of the proposed Phase II rule.

EPA's analysis showed that the proposed Phase II rule would not have a significant economic impact on a substantial number of small entities (SISNOSE). This finding is based on: (1) the limited absolute number of small entities expected to incur compliance costs; (2) the low percentage of all small entities in the entire electric generating industry expected to incur compliance costs; and (3) the insignificant magnitude of compliance costs as a percentage of sales revenues.

[1] The North American Industry Classification System (NAICS) replaced the Standard Industrial Classification (SIC) System as of October 1, 2000. The data sources EPA used to identify the parent entities of the facilities subject to this rule did not provide NAICS codes at the time of this analysis.

B4-1 Number of In-Scope Facilities Owned by Small Entities

EPA's 2000 Section 316(b) Industry Survey identified 539 generating facilities expected to meet the in-scope requirements of the Proposed Section 316(b) Phase II Existing Facilities Rule. As described in previous chapters of this document, these 539 facilities represent 550 facilities in the industry.[2] It is impossible, however, to determine the parent entity of extrapolated facilities. The remainder of this parent size analysis therefore discusses research done for the 539 surveyed facilities only. Later steps of this RFA analysis extrapolate the small entity findings to the industry level.

The small entity determination for in-scope facilities was conducted in two steps:

- Determine the domestic parent entity of the 539 in-scope facilities.
- Determine the size of the entities owning the 539 facilities.

B4-1.1 Identification of Domestic Parent Entities

Each of the 539 Phase II facilities belongs to one of the following seven types of domestic parent entity: private, federal, state, municipality, municipal marketing authority, political subdivision, or rural electric cooperative. In order to determine the domestic parent entity for each of the 539 facilities, EPA used publicly available data from the Department of Energy's (DOE) Energy Information Administration, 1999 Forms 860A and 860B. Information from the Section 316(b) Industry Survey was also used for facilities owned by nonutilities. Due to the recent changes in the electric generating industry, EPA used the Electric Power Monthly, a publication by the EIA, to identify in-scope facilities that have been sold to nonutilities and their new owners. As of the January 2002 Electric Power Monthly publication, EPA identified 112 facilities that had been sold to a nonutility since 1999. Of these 112 facilities, 105 were previously owned by a private utility, four were owned by a rural electric cooperative, two were owned by a political subdivision, and one was owned by a municipality. For facilities that have not been sold to a nonutility and that are not owned by a private entity, EPA assumed that the owner presented in the 1999 Forms EIA-860A and EIA-860B is the facility's domestic parent entity. For all other facilities, EPA conducted additional research to determine the domestic parent entity.

For facilities owned by a private entity, the immediate utility or nonutility owner is not necessarily the domestic parent firm. Many privately-owned utilities and nonutilities are owned by holding companies. A holding company is defined by the U.S. Census Bureau as being "primarily engaged in holding the securities of (or equity interests in) companies and enterprises for the purpose of owning a controlling interest or influencing the management decisions of these firms" (U.S. DOC, 2002). EPA used publicly available data and the Dun and Bradstreet (D&B) database to determine the domestic parent entity for all facilities either owned by a private entity or sold since 1999. The following four publicly available data sources were primarily used: the Security and Exchange Commission's (SEC) *FreeEdgar* database, the *Hoover's Online* website, Wright Investors' Service, and ZapData, an internet service of iMarket Inc. EPA determined that 131 unique entities own the 539 in-scope facilities.

[2] EPA applied sample weights to the 539 facilities to account for non-sampled facilities and facilities that did not respond to the survey. For more information on EPA's 2000 Section 316(b) Industry Survey, please refer to the Information Collection Request (U.S. EPA, 1999a).

B4-1.2 Size Determination of Domestic Parent Entities

The thresholds used by EPA to determine if a domestic parent entity is small depend on the entity type. Therefore, EPA used multiple data sources to determine the entity sizes. The entity size thresholds and data sources EPA used are:

- For ***private*** entities (including utilities and nonutilities), the small entity size is defined based on the parent entity's SIC code and the related size standard set by the Small Business Administration (SBA). The SBA standards are based on employment, sales revenue, or total electric output (in megawatt hours (MWh)), by four-digit SIC code. EPA used publicly available data sources, including the SEC's *FreeEdgar* database, the *Hoover's Online* website, Wright Investors' Service, and iMarket's ZapData, to obtain the information necessary to determine the entity size. Table B4-1 presents the unique Phase II firm-level SIC codes and the corresponding SBA size standards that were used to determine the size of privately-owned entities.

- All ***federal and state*** governments are assumed to be large for the purpose of the RFA analysis (U.S. EPA, 1999).

- ***Municipalities, municipal marketing authorities, and political subdivisions*** are considered public sector entities. Public sector entities are defined as small if they serve a population of less than 50,000. Population data for these entities was obtained from the U.S. Census Bureau, Population Estimates Program.

- The SBA threshold for SIC 4911 (4 million MWh of total electric output) was used for the size determination of ***rural electric cooperatives***. The size determination was based on 1999 Form EIA-861 data.

If the specific size standard information was not available for any of the 131 entities, EPA used the 4 million MWh total electric output size standard to determine the entity size.

Table B4-1: Unique Phase II Non-Government Entity SIC Codes and SBA Size Standards

SIC Code	SIC Description	SBA Size Standard
1311	Crude Petroleum and Natural Gas	500 Employees
3312	Steel Works, Blast Furnaces (Including Coke Ovens), and Rolling Mills	1,000 Employees
4911	Electric Services	4 million MWh
4924	Natural Gas Distribution	500 Employees
4931	Electric and Other Services Combined	$5.0 Million
4932	Gas and Other Services Combined	$5.0 Million
4939	Combination Utilities, NEC	$5.0 Million
4953	Refuse Systems	$10.0 Million
6512	Operators of Nonresidential Buildings	$5.0 Million
8711	Engineering Services	$6.0 Million

Source: U.S. SBA, 2000.

Based on these size thresholds, EPA determined that 26 out of the 131 unique entities owning the 539 in-scope facilities are small entities. In addition to the 26 entities EPA identified as small, two entities were of an unknown size. EPA assumed these two entities to be small. Therefore, out of the 131 unique entities, 28 were determined by EPA to be small. Nineteen of the 28 small entities are municipalities, six are rural electric cooperatives, two are municipal marketing authorities, and one is a political subdivision. None of the private entities owning in-scope facilities were found to be small entities. Table B4-2 presents the distribution of the unique entities by entity type and size.

Table B4-2: Phase II Unique Entities (by Entity Type and Size)

Entity Type	Small Entity Size Standard	Entity Size			Total
		Large	Small	Unknown	
Private	SIC Specific	70	-	-	70
Federal	Large	1	-	-	1
State	Large	4	-	-	4
Municipality	Population of 50,000	16	19	-	35
Municipal Marketing Authority	Population of 50,000	-	-	2	2
Political Subdivision	Population of 50,000	3	1	-	4
Rural Electric Cooperative	4 million MWh	9	6	-	15
Total		**103**	**26**	**2**	**131**

Source: U.S. EPA analysis, 2002.

The distribution of the weighted in-scope facilities by their owner's type and size is displayed in Table B4-3. No small entity owns more than one in-scope facility; therefore, the 28 small entities own 28 in-scope facilities.

Table B4-3: Phase II Facilities (by Entity Type and Size)

Entity Type	Small Entity Size Standard	Entity Size		Total
		Large	Small	
Private	SIC Specific	446	-	446
Federal	Large	13	-	13
State	Large	7	-	7
Municipality	Population of 50,000	29	19	48
Municipal Marketing Authority	Population of 50,000	-	2	2
Political Subdivision	Population of 50,000	7	1	8
Rural Electric Cooperatives	4 million MWh	19	6	25
Total [a]		**521**	**28**	**550**

[a] Individual numbers may not add up to total due to independent rounding.

Source: U.S. EPA analysis, 2002.

B4-2 Percent of Small Entities Regulated

In order to assess the impact of the proposed Phase II rule on the electric generating industry universe, EPA compared the number of in-scope small entities to the number of small entities in the entire electric generating industry. As discussed above, EPA identified 28 small entities (26 small and 2 unknown) subject to the proposed Phase II rule. Since only facilities with design intake flows of 50 MGD or more are subject to the proposed rule, the low number of small entities owning in-scope facilities is not unexpected. EPA identified 2,160 small entities within the entire electric power industry from the methods discussed below. Overall, only a small percentage of all small entities in the entire electric power industry, 1.3 percent, is subject to the proposed Phase II rule.

Based on Form EIA-861, 3,315 unique utilities operated in the United States in 1999.[3] It was not feasible to conduct the same research for all 3,315 utilities that was done for the 131 entities owning in-scope facilities (i.e., determining the holding companies and their SIC code and size standard information for private entities, and the population size for public sector entities). EPA therefore determined the industry-wide number of small entities based on the electricity sales threshold of 4 million MWh, using the 1999 Form EIA-861. However, EPA's analysis of the 131 entities that own in-scope facilities showed that the small entity determination based on the 4 million MWh threshold is not always the same as that based on the SIC code or population thresholds. EPA therefore made the following adjustments to the industry-wide numbers of small private entities, and municipalities:

- ***Private entities:*** EPA identified five privately-owned in-scope utilities that would qualify as small entities based on the 4 million MWh total electric output threshold. However, EPA's holding company research showed that all five small utilities would be considered large at the holding company level. EPA therefore assumed that industry-wide, all privately-owned utilities are large entities.

- ***Municipalities:*** EPA's research of entities owning in-scope facilities showed that 33 municipalities, municipal marketing authorities, and political subdivisions would be small based on the 4 million MWH size standard. Of these 33 entities, however, 39.4 percent, or 13 would be considered large when using the population threshold. EPA therefore reduced the number of small entity municipalities, municipal marketing authorities, and subdivisions within Form EIA-861 by a factor of 39.4 percent.

[3] It should be noted that the total number of small entities in the industry used in this analysis is based on utilities only. Information on the entity size of nonutilities is not readily available. The total number of small entities in the industry may therefore be understated, and, as a result, the percentage of small entities subject to the proposed Phase II rule may be overstated.

Table B4-4 presents the adjusted industry-wide number of small entities, the number of small entities that own in-scope facilities, and the percent of all small entities that is subject to the proposed Phase II rule.

Table B4-4: Number of Small Entities (Industry Total and Entities with In-Scope Facilities)

Type of Entity	Total Number of Small Entities	Number of Small Entities with In-Scope Facilities	Percent of Small Entities Subject to the Proposed Phase II Rule
Municipality	1,110	19	1.7%
Municipal Marketing Authority	13	2	15.4%
Political Subdivision	63	1	1.6%
Power Marketers	97	0	0.0%
Rural Electric Cooperatives	877	6	0.7%
All Firm Types	**2,160**	**28**	**1.3%**

Source: U.S. DOE, 1999c; U.S. EPA, 2000; D&B Database,2002.

B4-3 Sales Test for Small Entities

The final step in the RFA analysis consists of analyzing the cost-to-revenue ratio of each small entity subject to this proposed rule (also referred to as the "sales test"). The analysis is based on the ratio of estimated annualized post-tax compliance costs to annual revenues of the entity. EPA used a threshold of three percent to determine entities that would experience a significant economic impact as a result of the proposed Phase II regulation.

None of the 28 facilities EPA determined to be owned by a small entity has more than one owner. Also, none of the 28 small entities owns more than one in-scope facility. Therefore, no small entity is expected to incur compliance costs for more than one facility under the proposed rule.

The estimated annualized post-tax compliance costs include all technology costs, operation and maintenance costs, and permitting costs associated with the proposed Phase II rule. A detailed summary of how these costs were developed is presented in *Chapter B1: Summary of Compliance Costs*. For the 28 small entities, EPA calculated the average revenues over a three year period (1996 through 1998), using data from Form EIA-861.

The overall annualized compliance costs that facilities owned by small entities are estimated to incur represent between 0.1 and 5.3 percent of the entities' annual sales revenues. Table B4-5 presents the distribution of the entities' cost-to-revenue ratios by small entity type. Of the 28 small entities, two would incur compliance costs of greater than three percent of revenues. Nine entities would incur compliance costs of between one and three percent of revenues, while the remaining 17 entities would incur compliance costs of less than one percent of revenues.

Table B4-5: Impact Ratio Ranges by Small Entity Type

Type of Entity	Impact Ratio Ranges	0-1%	1-3%	>3%	Total
Municipality	0.4 to 5.3%	9	8	2	19
Municipal Marketing Authority	0.1 to 0.1%	2	0	0	2
Political Subdivision	1.2 to 1.2%	0	1	0	1
Rural Electric Cooperative	0.2 to 0.5%	6	0	0	6
Total	**0.1 to 5.3%**	**17**	**9**	**2**	**28**

Source: U.S. EPA analysis, 2002.

EPA has determined that, overall, the impacts faced by small entities as a result of the proposed Phase II rule are very low. Of the 28 entities owning in-scope facilities, only 2, approximately seven percent, would incur compliance costs of greater than three percent of revenues. Moreover, these two entities represent only 1.5 percent of all 131 entities owning in-scope facilities.

B4-4 SUMMARY

Under the Proposed section 316(b) Phase II Existing Facilities Rule, only 28 of 550 in-scope facilities would be owned by a small entity. The absolute number of small entities potentially subject to this regulation, 28, is low. Additionally, only a small percentage, 1.3 percent, of all small entities in the electric power industry is subject to this rule. Finally, the costs incurred by the 28 small entities are low representing between 0.1 and 5.3 percent of the entities' annual sales revenue. EPA therefore finds that this proposed rule would not have a significant economic impact on a substantial number of small entities (SISNOSE).

The RFA analysis in support of this proposed Phase II rule is summarized in Table B4-6.

Table B4-6: Summary of RFA Analysis

Type of Entity	Total Number of Small Entities	Number of Small Entities with In-scope facilities	Percent of Small Entities In-Scope of Rule	Annual Compliance Costs/ Annual Sales Revenue
Municipality	1,110	19	1.7%	0.4 to 5.3%
Municipal Marketing Authority	13	2	15.4%	0.1 to 0.1%
Political Subdivision	63	1	1.6%	1.2 to 1.2%
Power Marketers	97	0	0.0%	n/a
Rural Electric Cooperative	877	6	0.7%	0.2 to 0.5%
Total	**2,160**	**28**	**1.3%**	**0.1 to 5.3%**

Source: U.S. EPA analysis, 2002.

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Chapter B5: UMRA Analysis

INTRODUCTION

Title II of the Unfunded Mandates Reform Act of 1995, Pub. L. 104-4, establishes requirements for Federal agencies to assess the effects of their regulatory actions on state, local, and Tribal governments and the private sector. Under section 202 of UMRA, EPA generally must prepare a written statement, including a cost-benefit analysis, for proposed and final rules with "Federal mandates" that might result in expenditures to state, local, and Tribal governments, in the aggregate, or to the private sector, of $100 million or more in any one year.

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Before promulgating a regulation for which a written statement is needed, section 205 of UMRA generally requires EPA to identify and consider a reasonable number of regulatory alternatives and adopt the least costly, most cost-effective, or least burdensome alternative that achieves the objectives of the rule. The provisions of section 205 do not apply when they are inconsistent with applicable law. Moreover, section 205 allows EPA to adopt an alternative other than the least costly, most cost-effective, or least burdensome alternative if the Administrator publishes with the proposed rule an explanation why that alternative was not adopted. Before EPA establishes any regulatory requirements that might significantly or uniquely affect small governments, including Tribal governments, it must have developed under section 203 of the UMRA a small government agency plan. The plan must provide for notifying potentially affected small governments, enabling officials of affected small governments to have meaningful and timely input in the development of EPA regulatory proposals with significant intergovernmental mandates, and informing, educating, and advising small governments on compliance with regulatory requirements.

EPA estimates that facilities subject to the proposed Phase II rule would incur annualized post-tax compliance costs of $182.4 million ($2001). Of this total, $153.0 million is incurred by private sector facilities, $19.6 million is incurred by facilities owned by state and local governments, and $9.8 million is incurred by facilities owned by the federal government.[1] Permitting authorities incur an additional $3.6 million to administer the rule, including labor costs to write permits and to conduct compliance monitoring and enforcement activities. EPA estimates that the highest undiscounted cost incurred by the private sector in any one year is approximately $480 million in 2005. The highest undiscounted cost incurred by the state and local governments in any one year is approximately $42 million in 2005 (including facility compliance costs and state implementation cost). Thus, EPA has determined that this rule contains a Federal mandate that may result in expenditures of $100 million or more for state, local, and Tribal governments, in the aggregate, or the private sector in any one year. Accordingly, EPA has prepared under §202 of the UMRA a written statement which is summarized below.

B5-1 ANALYSIS OF IMPACTS ON GOVERNMENT ENTITIES

Governments may incur two types of costs as a result of this proposed rule:

- direct costs to comply with the rule for facilities owned by government entities, and
- administrative costs to implement the regulation.

Both types of costs incurred by governments are discussed below.

[1] The costs incurred by the federal government are not part of the unfunded mandates analyses and are therefore not included in the remainder of this chapter. The federal government owns 13 of the 550 Phase II facilities.

B5-1.1 Compliance Costs for Government-Owned Facilities

Of the 550 existing in-scope facilities subject to the proposed rule, 65 are owned by a state or local government. These 65 facilities are owned by 45 government entities. None of the Phase II facilities are owned by a Tribal government. Table B5-1 presents the number of government entities that own facilities subject to the proposed rule and the number of in-scope facilities by ownership type. Of the 65 facilities that are owned by government entities, 48 are owned by municipalities, two are owned by municipal marketing authorities, seven are owned by state governments, and eight are owned by political subdivisions.

Table B5-1 also presents the total annualized compliance costs of the 65 facilities by owner type, the average annualized cost per facility, and the maximum undiscounted cost by the 65 government-owned facilities in any one year. The total annualized compliance costs incurred by the 65 government-owned Phase II facilities is $19.6 million, or approximately $301,300 per facility.[2] The seven state-owned facilities account for the largest average annualized compliance cost, with approximately $445,000 per facility. The maximum undiscounted cost by the 65 facilities is $36.3 million, estimated to be incurred in 2005. The 48 facilities owned by municipalities incur the largest share of this cost, with $27.4 million.

Table B5-1: Number of Government Entities and Government-Owned Facilities

Ownership Type	Number of Government Entities	Number of Facilities	Total Annualized Compliance Costs (in millions, $2001)	Average Compliance Cost (per facility)	Maximum One-Year Facility Compliance Costs (in millions, $2001)
Municipality	35	48	$14.1	$293,100	$27.4
Municipal Marketing Authority	2	2	$0.4	$206,300	$0.5
State Government	4	7	$3.1	$445,200	$4.7
Political Subdivision	4	8	$2.0	$248,500	$3.8
Total	**45**	**65**	**$19.6**	**$301,300**	**$36.3**

Source: U.S. EPA analysis, 2002.

B5-1.2 Administrative Costs

The requirements of section 316(b) are implemented through the National Pollutant Discharge Elimination System (NPDES) permit program. Forty-four states and one territory currently have NPDES permitting authority under Section 402(c) of the Clean Water Act (CWA). EPA estimates that states and territories will incur three types of costs associated with implementing the requirements of the proposed rule: (1) start-up activities; (2) permitting activities associated with the initial NPDES permit containing the new section 316(b) requirements and subsequent permit renewals; and (3) annual activities.[3] EPA estimates that the total costs for these activities will be $3.62 million, annualized over 30 years at a seven percent rate. Table B5-2 below presents the annualized costs of the three major administrative activities.

[2] *Chapter B1: Summary of Compliance Costs* of this Economic and Benefits Analysis (EBA) presents information on the unit costs used to estimate facility compliance costs and the assumptions used to calculated annualized costs.

[3] The costs associated with implementing the requirement of the proposed Phase II rule are documented in EPA's Information Collection Request (U.S. EPA, 2002).

Table B5-2: Annualized Government Administrative Costs (in millions, $2001)

Activity	Cost
Start-Up Activities	$0.02
Permitting Activities	$2.66
Annual Activities	$0.94
Total	**$3.62**

Source: U.S. EPA analysis, 2002.

The start-up costs are incurred only once by each of the 45 permitting authorities. The first permit containing the new section 316(b) requirements, permit renewals, and annual activities are incurred on a per-permit basis. Based on the specific permitting requirements of each in-scope facility, EPA calculated total government costs of implementing the proposed Phase II rule by aggregating the unit costs for the first post-promulgation permit, and the repermitting and annual activities. The maximum one-year undiscounted implementation cost incurred by the government is $6.4 million, in 2006.

The incremental administrative burden on states will also depend on the extent of each state's current practices for regulating cooling water intake structures (CWIS). States that currently require relatively modest analysis, monitoring, and reporting of impacts from CWIS in NPDES permits may require more permitting resources to implement the proposed Phase II rule than are required under their current programs. Conversely, states that currently require very detailed analysis may require fewer permitting resources to implement the proposed rule than are currently required.

The following subsections present more detail on the three types of implementation costs.

a. Start-up activities

Forty-four states and one territory with NPDES permitting authority are expected to undertake start-up activities to prepare for administering the proposed rule. Start-up activities include reading and understanding the rule, mobilization and planning of the resources required to address the rule's requirements, and training technical staff on how to review materials submitted by facilities and make determinations on the proposed Phase II rule requirements for each facility's NPDES permit. In addition, permitting authorities are expected to incur other direct costs, e.g., for copying and the purchase of supplies. Table B5-3 shows the total start-up costs EPA estimated permitting authorities to incur. Each permitting authority will incur start-up costs of $3,546 as a result of the proposed Phase II rule. EPA assumes that the initial start-up activities will be incurred by all permitting authorities at the end of 2003, the year of promulgation of the Final Section 316(b) Phase II Existing Facilities Rule.

Table B5-3: Government Costs of Start-Up Activities (per Regulatory Authority)

Start-Up Activity	Start-Up Costs
Read and Understand Rule	$877
Mobilization/Planning	$1,526
Training	$1,093
Other Direct Costs	$50
Total	**$3,546**

Source: U.S. EPA analysis, 2002.

b. Initial post-promulgation permitting and repermitting activities

The permitting authorities will be required to implement the section 316(b) Phase II rule by adding compliance requirements to each facility's NPDES permit. Permitting activities include incorporating section 316(b) requirements into the first post-promulgation permit and making modifications, if necessary, to each subsequent permit. The first permit containing the new section 316(b) requirements will be issued between 2004 and 2008.[4] Repermitting activities will take place every five years after initial permitting.

The proposed Phase II rule requires facilities to submit the same type of information for their initial post-promulgation permit and for each permit renewal application. Therefore, the type of administrative activities are similar for the initial post-promulgation and each subsequent permit. EPA identified the following major activities associated with state permitting activities: reviewing submitted documents and supporting materials, verifying data sources, consulting with facilities and the interested public, determining specific permit requirements, and issuing the permit. Table B5-4 below presents the state permitting activities and associated costs on a per permit basis. The permitting costs do not vary by type of facility to be permitted. The burden of repermitting is expected to be smaller than for the initial post-promulgation permit because the permitting authority is already familiar with the facility's case and the type of information the facility will provide.

Two of the permitting activities presented within Table B5-4 pertain only to facilities opting for a site-specific determination of best technology available (BTA). An authorized state is able to permit a facility to opt for alternative regulatory requirements if it can demonstrate that the alternative requirements will result in environmental performance within a watershed that is comparable to the reductions in impingement mortality and entrainment comparable to those otherwise achieved under the proposed Phase II rule. EPA estimates that 10 regulatory permitting authorities would incur permitting costs associated with site-specific determinations.

[4] For an explanation of how the compliance years were assigned to facilities subject to the proposed Phase II rule, see *Chapter B1: Summary of Compliance Costs* of this EBA.

Table B5-4: Government Permitting Costs (per Permit)

Activity	Post-Promulgation Permit	Repermitting
Review Source Water Physical Data	$261	$102
Review CWIS Data	$782	$232
Review Source Water Baseline Biological Characterization Data	$1,462	$439
Review Proposal for Collection of Information for Comprehensive Demonstration Study	$1,170	$366
Review Source Water Body Flow Information	$261	$102
Review Design and Construction Technology Plan	$1,297	$369
Review Impingement Mortality & Entrainment Characterization Study	$19,230	$5,769
Review Evaluation of Potential CWIS Effects	$1,170	$366
Review Restoration Measures[a]	$2,066	$620
Review Information to Support Site-Specific Determination of BTA[b]	$41,320	$12,396
Determine Monitoring Frequency	$261	$102
Determine Record Keeping and Reporting Frequency	$261	$102
Establish Requirements for Site-Specific Technology[b]	$1,042	$289
Considering Public Comments	$1,170	$366
Issuing Permits	$238	$57
Permit Record Keeping	$117	$22
Other Direct Costs	$300	$300
Total[c]	**$72,405**	**$21,996**
Site Specific Costs	**$42,362**	**$12,685**

[a] Assumed to apply to only 10 percent of facilities.
[b] Cost incurred only for facilities conducting site-specific demonstrations.
[c] Individual numbers may not add up to total due to independent rounding.

Source: U.S. EPA analysis, 2002.

Initial post-promulgation permits that require all of the components listed in the table above are expected to impose a per permit cost per of $72,405 on the permitting authority. A majority of the initial permitting costs result from the facility option for a site-specific determination of BTA. For the initial post-promulgation permit, the state administrative costs associated with the site-specific determination are estimated to be $42,362, or approximately 59 percent of the total permitting costs. Permitting authorities would incur a maximum permit cost of $30,043 for facilities that do not conduct a site specific determination for their initial post-promulgation permit.

The maximum state administrative cost for a permit renewal is $21,996. For facilities that do not conduct a site specific determination, the cost per permit imposed on the permitting authority is reduced by $12,685, resulting in a maximum permit cost of $9,311.

c. Annual activities

In addition to the start-up and permitting activities previously discussed, permitting authorities will have to carry out certain annual activities to ensure the continued implementation of the requirements of the proposed Phase II rule. These annual activities include reviewing yearly status reports, tracking compliance, determination on monitoring frequency reduction, and record keeping.

Table B5-5 below shows the annual activities that will be necessary for each permit, beginning in the year after the first post-promulgation permit, and the estimated costs of each activity. A total cost of $1,712 is estimated for each permit per year.

Table B5-5: Government Costs for Annual Activities (per Permit)

Annual Activity	Annual Costs
Review of Yearly Status Report	$610
Compliance Tracking	$521
Determination on Monitoring Frequency Reduction	$407
Record Keeping	$124
Other Direct Costs	$50
Total	**$1,712**

Source: U.S. EPA analysis, 2002.

B5-1.3 Impacts on Small Governments

EPA's analysis also considered whether the proposed rule may significantly or uniquely affect small governments (i.e., governments with a population of less than 50,000). Table B5-6 presents by ownership size: (1) the number of entities owning facilities subject to the regulation; (2) the number of facilities; (3) compliance costs; and (4) the estimated average compliance cost per facility. EPA identified 22 facilities (of the 65 government-owned facilities) subject to the proposed rule that are owned by small governments.[5]

Table B5-6 shows that the estimated annualized compliance cost for all government-owned facilities is $19.6 million. The 43 facilities owned by large governments would incur costs of $13.6 million; the 22 facilities owned by small governments would incur costs of $6 million.

[5] *Chapter B4: Regulatory Flexibility Analysis* of this EBA provides more information on EPA's determination of the size of entities owning the 550 in-scope facilities.

Table B5-6: Number of Regulated Facilities and Compliance Costs by Entity Size

Ownership Size	Number of Entities	Number of Facilities Subject to Regulation	Annualized Compliance Costs (in millions, $2001)	Average Compliance Cost per Facility	Maximum One-Year Facility Compliance Costs (in millions, $2001)
Facilities Owned by Small Governments	22	22	$6.0	$272,200	$9.7
Facilities Owned by Large Governments	23	43	$13.6	$283,300	$26.6
All Government-Owned Facilities	45	65	$19.6	$301,400	$36.3
All Privately-Owned Facilities	85	471	$153.0	$324,700	$479.0

Source: U.S. EPA analysis, 2002.

The total annualized compliance cost for the 22 facilities owned by small governments is $6.0 million, or approximately $272,000 per facility. In comparison, the total annualized compliance cost for the 43 facilities owned by large governments is $13.6 million, or approximately $283,000 per facility. For all of the 471 privately-owned facilities, the total annualized compliance cost is $182.4 million, or approximately $331,600 per facility. These numbers support EPA's analysis in showing that small governments would not be significantly or uniquely affected by the proposed Phase II rule. The per facility average compliance cost incurred by facilities owned by small governments is less than the per facility compliance costs incurred by facilities owned by large governments and privately-owned facilities subject to the proposed Phase II rule.

B5-2 Compliance Costs for the Private Sector

The private sector only incurs compliance costs associated with facilities subject to this proposed rule. These direct facility costs already include the cost to facilities of obtaining their NPDES permits. Of the 550 in-scope facilities subject to the proposed rule, EPA identified 471 to be owned by a private entity.

Compliance costs for individual facilities are presented in *Chapter B1: Summary of Compliance Costs* of this EBA. Total annualized (post-tax) compliance costs for the 471 privately-owned facilities are estimated to be $153.0 million, discounted at seven percent. The maximum aggregate costs (undiscounted) for all 471 facilities in any one year is estimated to be $479.0 million, incurred in 2005.

B5-3 SUMMARY OF UMRA ANALYSIS

EPA estimates that the Proposed Section 316(b) Existing Facilities Rule will result in expenditures of $100 million or greater for state and local governments, in the aggregate, or for the private sector in any one year. Table B5-7 summarizes the costs to comply with the rule for the 537 in-scope facilities (excluding the 13 facilities owned by the federal government) and the costs to implement the rule, borne by the responsible regulatory authorities.

Table B5-7: Summary of UMRA Costs (in millions, $2001)

Sector	Total Annualized Cost (Post-Tax)			Maximum One-Year Cost		
	Facility Compliance Costs	Government Implementation Costs	Total	Facility Compliance Costs	Government Implementation Costs	Total
Government Sector	$19.6	$3.6	$23.2	$36.3	$5.8	$42.2
Private Sector	$153.0	n/a	$153.0	$479.0	n/a	$479.0

Source: U.S. EPA Analysis, 2002.

The total annualized (post-tax) costs of the Proposed Section 316(b) Phase II Existing Facilities Rule borne by governments is approximately $23.2 million, consisting of $19.6 million in facility compliance costs and $3.6 million in government implementation costs. The maximum one-year costs that will be incurred by government entities is expected to be $42.2 million ($36.3 million in facility compliance costs and $5.8 million in implementation costs), incurred in 2005. Total annualized costs borne by the private sector is estimated by EPA to be $153 million. The maximum one-year cost to the private sector is $479 million, incurred in 2005.

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Chapter B6: Other Administrative Requirements

Introduction

This chapter presents several other analyses in support of the Proposed Phase II Existing Facilities Rule. These analyses address the requirements of Executive Orders and Acts applicable to this rule.

Chapter Contents

B6-1 Executive Order 12866: Regulatory Planning and Review

Under Executive Order 12866 (58 FR 51735, October 4, 1993), the Agency must determine whether the regulatory action is "significant" and therefore subject to OMB review and the requirements of the Executive Order. The order defines a "significant regulatory action" as one that is likely to result in a rule that may:

- have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or state, local, or Tribal governments or communities; or
- create a serious inconsistency or otherwise interfere with an action taken or planned by another agency; or
- materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or
- raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, EPA determined that this proposed rule is a "significant regulatory action." As such, this action was submitted to OMB for review. Changes made in response to OMB suggestions or recommendations are documented in the public record.

B6-2 Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 11, 1994) requires that, to the greatest extent practicable and permitted by law, each Federal agency must make achieving environmental justice part of its mission. E.O. 12898 provides that each Federal agency must conduct its programs, policies, and activities that substantially affect human health or the environment in a manner that ensures such programs, policies, and activities do not have the effect of (1) excluding persons (including populations) from participation in, or (2) denying persons (including populations) the benefits of, or (3) subjecting persons (including populations) to discrimination under such programs, policies, and activities because of their race, color, or national origin.

Today's final rule would require that the location, design, construction, and capacity of cooling water intake structures (CWIS) at Phase II existing facilities reflect the best technology available for minimizing adverse environmental impact. For several reasons, EPA does not expect that this final rule would have an exclusionary effect, deny persons the benefits of the participation in a program, or subject persons to discrimination because of their race, color, or national origin.

In fact, because EPA expects that this final rule would help to preserve the health of aquatic ecosystems located in reasonable proximity to Phase II existing facilities, it believes that all populations, including minority and low-income populations, would benefit from improved environmental conditions as a result of this rule. Under current conditions, EPA estimates approximately 2.2 billion fish (expressed as age 1 equivalents) of recreational and commercial species are lost annually due to impingement and entrainment at the 539 in-scope Phase II existing facilities. Under the proposed regulation, over 1.2 billion individuals of these commercially and recreationally sought fish species (age 1 equivalents) will now survive to join the fishery each year (435 million fish due to reduced impingement impacts, and 789 million fish due to reduced entrainment). These additional 1.2 billion fish will provide increased opportunities for subsistence anglers to increase their catch, thereby providing some benefit to low income households located near regulation-impacted waters.

The greatest benefits from this rule may be realized by populations that fish for subsistence purposes. While the extent of subsistence fishing in the U.S. or in individual states and cities is not generally known, it is known that Native Americans and low income Southeast Asians are the major population subgroups participating in subsistence fishing. However, Native Americans fishing on reservations are not required to obtain a license, so records of the number of Native Americans fishing on reservations are not available. Similarly, Southeast Asians often do not purchase licenses and therefore the extent of their participation in subsistence fishing is unknown.

Due to the lack of data, EPA uses simplifying assumptions to estimate the number of subsistence fishermen. In some past analyses, EPA assumed that subsistence fishermen constitute 5 percent of the total licensed population. This assumption is, however, likely to understate the number of recreational fishers, because although fishing licenses may be sold to subsistence fishermen, many of these individuals do not purchase fishing licenses. Therefore, in more recent analyses EPA has assumed that the number of subsistence fishermen would constitute an additional 5 percent of the licensed fishing population. Using this 10 percent assumption, the number of subsistence fishermen that may benefit from increased fish populations as a result of this rule is substantial.

Based on estimates of the number of anglers calculated from the *1996 National Survey of Fishing, Hunting, and Wildlife-Associated Recreation* (U.S. DOI 1997), the average in-scope facility has a subsistence population of nearly 15,000 people living within 50 miles of the facility. EPA estimated average subsistence populations by waterbody type. The results indicate that, although the estimated subsistence fishing population comprises a small percentage of the total population, a significant number of persons may engage in subsistence fishing within the vicinity of in-scope facilities. The results of this analysis are presented in Table B6-1.

Table B6-1: Estimated Subsistence Fishing Population Within 50-mile Radius of In-scope Facilities [a]

Waterbody Type	Number of In-Scope Facilities	Average 2000 Population[b]	Average Estimated Subsistence Fishing Population[a]
Estuary - NonGulf	78	7,045,000	20,000
Estuary - Gulf	30	1,845,000	12,000
Freshwater	393	1,578,000	14,000
Great Lake	16	3,195,000	6,000
Ocean	22	5,101,000	13,000
All In-Scope Facilities	**539**	**2,576,000**	**15,000**

[a] Estimated as 10% of total estimated anglers living within 50 miles of an in-scope facility. Rounded to nearest thousand.
[b] Rounded to the nearest thousand.

Source: Angler estimates calculated from U.S. DOI, 1997; U.S. EPA analysis, 2002.

Because the estimates presented in Table B6-1 are estimates that are not based on actual subsistence fishing data, they may tend to underestimate or overestimate the actual levels of subsistence fishing within a given waterbody type. As a secondary

analysis, EPA calculated the poverty rate and the percentage of the population classified as non-white, Native American, and Asian for populations living within a 50-mile radius of each of the 539 in-scope facilities.

The results of this secondary analysis, presented in Table B6-2, show that the populations affected by the in-scope facilities have poverty levels and racial compositions that are quite similar to the U.S. population as a whole. In-scope facilities located on oceans and non-gulf estuaries do tend to have significant Asian populations. As such, in these areas persons that rely on subsistence fishing may benefit greatly due to increases in fish populations resulting from changes mandated by the rule. However, taken as a whole, a relatively small subset of the facilities are located near populations with poverty rates (24 of 539, or 4.5%), non-white populations (101 of 539, or 18.7%), Native American populations (30 of 539, or 5.6%), or Asian populations (48 of 539, or 8.9%) that are significantly higher than U.S. average levels.

Table B6-2 Demographics of Populations within 50-Mile Radius of In-Scope Facilities

Waterbody Type	Number of In-Scope Facilities	Average 1998 Poverty Rate	Average 2000 Percent of Population			Number of Facilities with Levels >= 1.5 Times the U.S. Level			
			Non-white[a]	Native American[b]	Asian[c]	Poverty Rate	Non-White Pop	Native American Pop	Asian Pop
Estuary - NonGulf	78	11.2%	28.5%	0.8%	6.2%	0	38	0	33
Estuary - Gulf	30	13.4%	24.0%	0.8%	2.5%	0	6	0	0
Freshwater	393	12.7%	17.5%	1.6%	1.7%	22	44	27	1
Great Lake	16	11.1%	19.5%	1.6%	2.3%	0	3	2	0
Ocean	22	13.7%	33.8%	1.6%	15.4%	2	10	1	14
All In-Scope Facilities	**539**	**12.5%**	**20.2%**	**1.4%**	**3.0%**	**24**	**101**	**30**	**48**
U.S.	**---**	**12.7%**	**22.9%**	**1.5%**	**4.2%**	**---**	**---**	**---**	**---**

[a] Non-white population defined as any person who did not indicate their race to be "White," either alone or in combination with one or more of the other races listed.

[b] Defined as any person who indicated their race to be "Native American" or "Native Alaskan" either alone or in combination with one or more of the other races listed

[c] Defined as any person who indicated their race to be "Asian" either alone or in combination with one or more of the other races listed.

Source: Non-white, Native American, and Asian population estimates compiled from U.S. DOC, 2000; Average poverty rate compiled from U.S. DOC, 1998.

Based on these results, EPA does not believe that this rule will have an exclusionary effect, deny persons the benefits of the NPDES program, or subject persons to discrimination because of their race, color, or national origin. To the contrary, it will increase the number of fish and other aquatic organisms available for subsistence, commercial, and recreational anglers of all races, color, and natural origin.

B6-3 Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks

Executive Order 13045 (62 FR 19885, April 23, 1997) applies to any rule that (1) is determined to be “economically significant” as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe might have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health and safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency. This proposed rule is an economically significant rule as defined under Executive Order 12866. However, it does not concern an

environmental health or safety risk that would have a disproportionate effect on children. Therefore, it is not subject to Executive Order 13045.

B6-4 EXECUTIVE ORDER 13132: FEDERALISM

Executive Order 13132 (64 FR 43255, August 10, 1999) requires EPA to develop an accountable process to ensure "meaningful and timely input by state and local officials in the development of regulatory policies that have federalism implications." Policies that have federalism implications are defined in the Executive Order to include regulations that 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."

Under section 6 of Executive Order 13132, EPA may not issue a regulation that has federalism implications, that imposes substantial direct compliance costs, 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 unless EPA consults with state and local officials early in the process of developing the proposed regulation. EPA also may not issue a regulation that has federalism implications and that preempts state law, unless the Agency consults with state and local officials early in the process of developing the proposed regulation.

This proposed 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 Executive Order 13132. EPA expects an annual burden of 146,983 hours for states to collectively administer this proposed rule. EPA has identified 65 Phase II existing facilities that are owned by state or local government entities. The annual impacts on these facilities are not expected to exceed 2,252 burden hours and $56,739 (non-labor costs) per facility.

The proposed national cooling water intake structure requirements would be implemented through permits issued under the NPDES program. Forty-five states and territories are currently authorized pursuant to section 402(b) of the CWA to implement the NPDES program. In states not authorized to implement the NPDES program, EPA issues NPDES permits. Under the CWA, states are not required to become authorized to administer the NPDES program. Rather, such authorization is available to states if they operate their programs in a manner consistent with section 402(b) and applicable regulations. Generally, these provisions require that state NPDES programs include requirements that are as stringent as Federal program requirements. States retain the ability to implement requirements that are broader in scope or more stringent than Federal requirements. (See section 510 of the CWA.)

EPA does not expect the proposed Phase II regulation to have substantial direct effects on either authorized or nonauthorized states or on local governments because it would not change how EPA and the states and local governments interact or their respective authority or responsibilities for implementing the NPDES program. This proposed rule establishes national requirements for Phase II existing facilities with cooling water intake structures. NPDES-authorized states that currently do not comply with the final regulations based on this rule might need to amend their regulations or statutes to ensure that their NPDES programs are consistent with Federal section 316(b) requirements. (See 40 CFR 123.62(e).) For purposes of this proposed rule, the relationship and distribution of power and responsibilities between the Federal government and the state and local governments are established under the CWA (e.g., sections 402(b) and 510); nothing in this proposed rule would alter that. Thus, the requirements of section 6 of the Executive Order do not apply to this rule.

Although section 6 of Executive Order 13132 does not apply to this rule, EPA did consult with state governments and representatives of local governments in developing definitions and concepts relevant to the section 316(b) regulation and this proposed rule:

- During the development of the proposed section 316(b) rule for new facilities, EPA conducted several outreach activities through which state and local officials were informed about this proposal. These officials then provided information and comments to the Agency. The outreach activities were intended to provide EPA with feedback on issues such as adverse environmental impact, BTA, and the potential cost associated with various regulatory alternatives.

- EPA has made presentations on the section 316(b) rulemaking effort in general at eleven professional and industry association meetings. EPA also conducted two public meetings in June and September of 1998 to discuss issues related to the section 316(b) rulemaking effort. In September 1998 and April 1999, EPA staff participated in technical workshops sponsored by the Electric Power Research Institute on issues relating to the definition and

assessment of adverse environmental impact. EPA staff have worked with numerous states such as New York, New Jersey, California, Rhode Island, and Massachusetts and regions such as Region 1 and Region 9.

- EPA met with the Association of State and Interstate Water Pollution Control Administrators (ASIWPCA) and, with the assistance of ASIWPCA, conducted a conference call in which representatives from 17 states or interstate organizations participated.

- EPA met with OMB and utility representatives and other federal agencies (the Department of Energy, the Small Business Administration, the Tennessee Valley Authority, the National Oceanic and Atmospheric Administration's National Marine Fisheries Service and the Department of Interior's U.S. Fish and Wildlife Service).

- EPA received more than 2000 comments on the Phase I proposed rule and Notice of Data Availability (NODA). In some cases these comments have informed the development of the Phase II rule proposal. State and local government representatives from the following states submitted comments: Alaska, California, Florida, Louisiana, Maryland, Michigan, Nebraska, New Hampshire, New Jersey, New York, North Carolina, North Dakota, Ohio, Pennsylvania, and Texas.

- On May 23, 2001, EPA held a day-long forum to discuss specific issues associated with the development of regulations under section 316(b). At the meeting, 17 experts from industry, public interest groups, states, and academia reviewed and discussed the Agency's preliminary data on cooling water intake structure technologies that are in place at existing facilities and the costs associated with the use of available technologies for reducing impingement and entrainment. Over 120 people attended the meeting.

In the spirit of this Executive Order and consistent with EPA policy to promote communications between EPA and state and local governments, the preamble to this proposed rule specifically solicited comment from state and local officials.

B6-5 Executive Order 13158: Marine Protected Areas

Executive Order 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 the Executive Order is to protect the significant natural and cultural resources within 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." EPA expects that the proposed Phase II Existing Facilities Rule will advance the objective of Executive Order 13158.

Marine protected areas include designated areas with varying levels of protection, from fishery closure areas, to aquatic National Parks, Marine Sanctuaries, and Wildlife Refuges (NOAA, 2002). The Departments of Commerce and the Interior have included sites that appear to meet the marine protected area definition in a nationwide inventory of marine protected areas. This list has not been completed yet, but includes 32 national sites in the New England region, 31 in the Middle Atlantic region, 43 sites in the South Atlantic region, and 46 in the U.S. Pacific Coast region. Examples of different types of marine protected areas currently in the list include the Great Bay National Wildlife Refuge in New Hampshire, the Cape Cod Bay Northern Right Whale Critical Habitat in Massachusetts, the Narragansett Bay National Estuarine Research Reserve in Rhode Island, Everglades National Park and the Tortugas Shrimp Sanctuary in Florida, and the Point Reyes National Seashore in California.

Marine protected areas can help address problems related to the depletion of marine resources by prohibiting, or severely curtailing, activities that are permitted or regulated by law outside of marine protected areas. Such activities include oil exploration, dredging, dumping, fishing, certain types of vessel traffic, and the focus of section 316(b) regulation, the impingement and entrainment of aquatic organisms by cooling water intake structures.

Impingement and entrainment affects many kinds of aquatic organisms, including fish, shrimp, crabs, birds, sea turtles, and marine mammals. Aquatic environments are harmed both directly and indirectly by impingement and entrainment of these organisms. In addition to the harm that results from the direct removal of organisms by impingement and entrainment, there are the indirect effects on aquatic food webs that result from the impingement and entrainment of organisms that serve as prey for predator species. There are also cumulative impacts that result from multiple intake structures operating in the same local area, or when multiple intakes affect individuals within the same population over a broad geographic range.

Decreased numbers of aquatic organisms resulting from the direct and indirect effects of impingement and entrainment can have a number of consequences for marine resources, including impairment of food webs, disruption of nutrient cycling and energy transfer within aquatic ecosystems, loss of native species, and reduction of biodiversity. By reducing the impingement and entrainment of aquatic organisms, the proposed Phase II Existing Facilities Rule will not only help protect individual species but also the overall marine environment, thereby advancing the objective of Executive Order 13158 to protect marine areas.

B6-6 Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

Executive Order 13175 (65 FR 67249, November 6, 2000) requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications." "Policies that have tribal implications" is defined in the Executive Order to include regulations that have "substantial direct effects on one or more Indian Tribes, on the relationship between the Federal government and the Indian Tribes, or on the distribution of power and responsibilities between the Federal government and Indian Tribes." This proposed rule does not have tribal implications. It will not have substantial direct effects on tribal governments, on the relationship between the Federal government and Indian Tribes, or on the distribution of power and responsibilities between the Federal government and Indian Tribes, as specified in Executive Order 13175. EPA's analyses show that no facility subject to this proposed rule is owned by tribal governments. This proposed rule does not affect Tribes in any way in the foreseeable future. Accordingly, the requirements of Executive Order 13175 do not apply to this rule.

B6-7 Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211 (66 FR 28355; May 22, 2001) requires EPA to prepare a Statement of Energy Effects when undertaking regulatory actions identified as "significant energy actions." For the purposes of Executive Order 13211, "significant energy action" means:

> "any action by an agency (normally published in the Federal Register) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking:
>
> (1) (i) that is a significant regulatory action under Executive Order 12866 or any successor order, and
>
> (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or
>
> (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs (OIRA) as a significant energy action."

For those regulatory actions identified as "significant energy actions," a Statement of Energy Effects must include a detailed statement relating to (1) any adverse effects on energy supply, distribution, or use (including a shortfall in supply, price increases, and increased use of foreign supplies), and (2) reasonable alternatives to the action with adverse energy effects and the expected effects of such alternatives on energy supply, distribution, and use.

This proposed rule does not qualify as a "significant energy action" as defined in Executive Order 13211 because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The proposed rule does not contain any compliance requirements that would directly reduce the installed capacity or the electricity production of U.S. electric power generators, for example through parasitic losses or auxiliary power requirements. In addition, based on the estimated costs of compliance, EPA currently projects that the rule will not lead to any early capacity retirements at facilities subject to this rule or at facilities that compete with them. As described in detail in *Chapter C3: Electricity Market Model Analysis*, EPA estimates small effects of this rule on installed capacity, generation, production costs, and electricity prices. EPA

therefore concludes that this proposed rule will have small energy effects at a national, regional, and facility-level. As a result, EPA did not prepare a Statement of Energy Effects.[1]

For more detail on the potential energy effects of this proposed rule or the alternative regulatory options considered by EPA, see *Chapter C3: Electricity Market Model Analysis* and *Chapter C7: Alternative Regulatory Options.*

B6-8 Paperwork Reduction Act of 1995

The Paperwork Reduction Act of 1995 (PRA) (superseding the PRA of 1980) is implemented by the Office of Management and Budget (OMB) and requires that agencies submit a supporting statement to OMB for any information collection that solicits the same data from more than nine parties. The PRA seeks to ensure that Federal agencies balance their need to collect information with the paperwork burden imposed on the public by the collection.

The definition of "information collection" includes activities required by regulations, such as permit development, monitoring, record keeping, and reporting. The term "burden" refers to the "time, effort, or financial resources" the public expends to provide information to or for a Federal agency, or to otherwise fulfill statutory or regulatory requirements. PRA paperwork burden is measured in terms of annual time and financial resources the public devotes to meet one-time and recurring information requests (44 U.S.C. 3502(2); 5 C.F.R. 1320.3(b)).

Information collection activities may include:

- reviewing instructions;
- using technology to collect, process, and disclose information;
- adjusting existing practices to comply with requirements;
- searching data sources;
- completing and reviewing the response; and
- transmitting or disclosing information.

Agencies must provide information to OMB on the parties affected, the annual reporting burden, the annualized cost of responding to the information collection, and whether the request significantly impacts a substantial number of small entities. An agency may not conduct or sponsor, and a person is not required to respond to, an information collection unless it displays a currently valid OMB control number.

EPA's estimate of the information collection requirements imposed by the proposed Phase II regulation are documented in the Information Collection Request (ICR) which accompanies this regulation (U.S. EPA, 2002).

B6-9 National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995, Pub L. No. 104-113, Sec. 12(d) 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 standard bodies. The NTTAA directs EPA to provide Congress, through the Office of Management and Budget (OMB), explanations when the Agency decides not to use available and applicable voluntary consensus standards.

This proposed rule does not involve such technical standards. Therefore, EPA is not considering the use of any voluntary consensus standards.

[1] EPA recognizes that some of the alternative regulatory options discussed in the preamble and analyzed in *Chapter C7: Alternative Regulatory Options* would have larger effects and might well qualify as "significant energy actions" under Executive Order 13211. If EPA decides to revise the proposed requirements for the final rule, it will reconsider its determination under Executive Order 13211 and prepare a Statement of Energy Effects as appropriate.

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Chapter B7: Alternative Options - Costs and Economic Impacts

Introduction

EPA considered the costs and economic impacts of four alternative regulatory options that would establish best technology available (BTA) for minimizing adverse environmental impact (AEI):[1]

- **(1) Waterbody/Capacity-Based Option (Options 1 and 2):** This option would require Phase II facilities located on estuaries, tidal rivers, and oceans to reduce intake capacity commensurate with the use of closed-cycle, recirculating cooling systems based on the volume of cooling water they withdraw. EPA analyzed two different cases of the waterbody/capacity-based option: the first case assumes that all facilities with recirculating cooling system-based requirements would comply with Track I and install a wet cooling tower (Option 1); the second, more likely, case assumes that a percentage of the facilities with recirculating cooling system-based requirements would comply with Track II and conduct a comprehensive waterbody characterization study and install technologies other than wet cooling towers (Option 2).

- **(2) Impingement Mortality and Entrainment Controls Everywhere Option (Option 3a):** This option would require all Phase II facilities to reduce impingement and entrainment to levels established based on the use of design and construction technologies (e.g., fine-mesh screens, fish return systems) or operational measures.

- **(3) All Cooling Towers Option (Option 4):** This option would require all Phase II facilities to reduce intake capacity commensurate with the use of closed-cycle, recirculating cooling systems.

- **(4) Dry Cooling Option (Option 5):** This option would require Phase II facilities located on estuaries, tidal rivers, and oceans to reduce intake capacity commensurate with the use of a dry cooling system based on the volume of cooling water they withdraw.

For each of these four alternative options, this chapter presents (1) the private annualized costs of compliance by NERC region and plant type;[2] (2) cost-to-revenue ratios at the facility and firm-levels; and (3) an analysis of potential impacts on small entities. The methodologies used to develop the estimates presented in this chapter are the same as those discussed in previous chapters of this EBA. *Chapter B1: Summary of Compliance Costs* and the *§ 316(b) Technical Development Document* present EPA's detailed analysis of the compliance cost components and national cost estimation; *Chapter B2: Cost*

Chapter Contents

[1] *Chapter A1: Introduction and Overview* of this Economic and Benefits Analysis (EBA) provides a more detailed discussion of the requirements of these alternative regulatory options. EPA also considered another waterbody-based option (Option 6) in which all facilities located on an estuary or tidal river or ocean must reduce intake flow commensurate with a level that can be achieved by a closed-cycle, recirculating system, regardless of proportional intake flow. This option was not costed and is not discussed in this chapter.

[2] For a count of Phase II facilities by NERC region and plant type, see *Chapter A2: Need for the Regulation* of this EBA.

Impact Analysis presents an assessment of the magnitude of compliance costs at the facility and firm-levels; and *Chapter B4: Regulatory Flexibility Analysis* considers the potential impact of the proposed Phase II rule on small entities.

B7-1 WATERBODY/CAPACITY-BASED OPTION (OPTIONS 1 AND 2)

The waterbody/capacity-based option would require facilities that withdraw very large amounts of water from an estuary, tidal river, or ocean to reduce their intake capacity to a level commensurate with that which can be attained by a closed-cycle, recirculating cooling system. EPA estimates that 54 facilities would be required to reduce intake flow to a level commensurate with that which can be attained by a closed-cycle recirculating system to comply with this option.

The cost for facilities to meet these standards could potentially be substantial if they installed a cooling tower. Under this option, EPA would provide an opportunity to seek alternative requirements to address locally significant air quality or energy impacts. While EPA is not proposing this option, EPA is considering it for the final rule.[3]

EPA analyzed two different cases of the waterbody/capcity based option: the first case assumes that all 54 facilities with recirculating cooling system-based requirements would comply with Track I and install a wet cooling tower; the second, more likely, case assumes that 33 facilities would comply with Track I and install a wet cooling tower and the remaining 21 facilities with flow reduction requirements would comply with Track II and conduct a comprehensive waterbody characterization study and install technologies other than wet cooling towers.

B7-1.1 Compliance Costs

EPA estimates that the total annualized private post-tax cost of compliance for the waterbody/capacity-based option ranges from approximately $379 million assuming 21 facilities comply with Track II (Option 2) to $595 million assuming all 54 facilities comply with Track I (Option 1).

Table B-2 presents the total annualized private costs by cost category and NERC region for both of the compliance responses analyzed. The NERC regions with the highest compliance costs, FRCC (Florida Reliability Coordinating Council), MAAC (Mid-Atlantic Area Council), NPCC (Northeast Power Coordinating Council), SERC (Southwestern Electric Reliability Council), and WSCC(Western Systems Coordinating Council) all contain coastal states with facilities withdrawing cooling water from estuaries, tidal rivers, or oceans.

Using the assumption that all 54 facilities with recirculating cooling system based requirements would comply with Track I (Option 1), the annualized cost by NERC region ranges from approximately $90,000 for facilities located in ASCC (Alaska Systems Coordinating Council) to $142 million for facilities located in NPCC (Northeast Power Coordinating Council). The capital technology cost, which includes the cost of cooling towers, comprises $226 million of the total $595 million cost (or 38 percent). The annual energy penalty and one-time connection outage costs represent $68 million (or 11 percent) and $26 million (or 4 percent), respectively. Annual operating and maintenance costs represent $242 million (or 41 percent) of total compliance costs. Permitting costs represent $34 million (or 6 percent) of total compliance costs.

Under the second, more likely, assumption that some facilities would comply with Track I and others with Track II (Option 2), the annualized cost by NERC region ranges from approximately $76,000 for facilities located in ASCC (Alaska Systems Coordinating Council) to $98 million for facilities located in NPCC (Northeast Power Coordinating Council). The capital technology cost comprises $162 million of the total $379 million cost (or 43 percent). The annual energy penalty and one-time connection outage costs represent $28 million (or 7 percent) and $22 million (or 6 percent), respectively. EPA estimates operating and maintenance costs to be $146 million (or 39 percent) of total compliance costs. Permitting costs represent $32 million (or 8 percent) of total compliance costs.

[3] EPA analyzed this option using the energy market model. For a detailed analysis, see *Chapter B8: Alternative Options - Electricity Market Model Analysis* of this Economic and Benefits Analysis (EBA).

Table B7-2: Private (Post-Tax) Annualized Compliance Costs by NERC Region (in millions, $2001) Waterbody/Capacity-Based Option

NERC Region	One-Time Costs		Recurring Costs		Permitting Costs	Total
	Capital Technology	Connection Outage	O&M	Energy Penalty		
All Track I (Option 1)						
ASCC	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1
ECAR	$15.2	$0.0	$3.6	$0.0	$5.9	$24.6
ERCOT	$8.5	$0.4	$12.2	$2.7	$3.5	$27.2
FRCC	$29.7	$5.4	$44.2	$15.3	$2.1	$96.7
HI	$5.5	$1.1	$5.4	$2.5	$0.2	$14.8
MAAC	$40.7	$3.2	$45.9	$9.1	$2.5	$101.4
MAIN	$6.4	$0.0	$1.4	$0.0	$3.0	$10.8
MAPP	$2.0	$0.0	$0.4	$0.0	$3.0	$5.3
NPCC	$54.7	$4.6	$66.2	$12.7	$3.8	$141.9
SERC	$27.5	$3.5	$28.1	$10.5	$5.9	$75.6
SPP	$1.3	$0.0	$0.4	$0.0	$2.1	$3.8
WSCC	$34.0	$7.3	$34.3	$15.1	$2.3	$93.0
Total	**$225.5**	**$25.5**	**$242.1**	**$67.9**	**$34.3**	**$595.3**
Track I and II (Option 2)						
ASCC	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1
ECAR	$15.2	$0.0	$3.6	$0.0	$5.0	$23.7
ERCOT	$7.7	$0.3	$10.3	$2.0	$3.1	$23.3
FRCC	$18.5	$0.9	$24.5	$3.7	$2.2	$49.7
HI	$5.5	$1.1	$5.4	$2.5	$0.2	$14.7
MAAC	$23.8	$1.1	$22.5	$3.1	$2.6	$53.2
MAIN	$6.4	$0.0	$1.4	$0.0	$2.5	$10.3
MAPP	$2.0	$0.0	$0.4	$0.0	$2.5	$4.9
NPCC	$40.0	$2.5	$45.8	$6.2	$3.9	$98.4
SERC	$20.7	$1.6	$13.4	$3.8	$5.4	$45.0
SPP	$1.3	$0.0	$0.4	$0.0	$1.8	$3.5
WSCC	$21.1	$3.5	$17.7	$7.0	$2.5	$51.8
Total	**$162.0**	**$11.0**	**$145.5**	**$28.4**	**$31.7**	**$378.6**

Source: U.S. EPA analysis, 2002.

Table B7-3 presents total annual facility compliance costs by cost category and steam plant type. The annual compliance costs under Option 1 range from $2 million for waste facilities to $232 million for oil and gas facilities. Under Option 2, total annual compliance costs range from $2 million for waste facilities to $189 million for oil and gas facilities

Table B7-3: Annualized Facility Compliance Costs by Steam Plant Type (in millions, $2001) Waterbody/Capacity-Based Option

Steam Plant Type	One-Time Costs		Recurring Costs			Total
	Capital Technology	Connection Outage	O&M	Energy Penalty	Permitting Costs	
All Track I (Option 1)						
Coal	$65.3	$5.3	$58.0	$17.6	$18.3	$164.6
Combined Cycle	$7.6	$0.4	$10.7	$1.3	$1.0	$21.1
Nuclear	$67.7	$14.3	$62.3	$27.4	$3.4	$175.2
Oil/Gas	$84.1	$5.4	$110.1	$21.5	$11.0	$232.1
Waste	$0.7	$0.0	$0.9	$0.2	$0.5	$2.3
Unspecified	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1
Total	**$225.5**	**$25.5**	**$242.1**	**$67.9**	**$34.3**	**$595.3**
Track I and II (Option 2)						
Coal	$42.5	$0.5	$16.9	$2.1	$16.5	$78.5
Combined Cycle	$7.6	$0.4	$10.7	$1.3	$0.9	$20.9
Nuclear	$38.8	$5.9	$29.7	$10.2	$3.6	$88.2
Oil/Gas	$72.4	$4.0	$87.2	$14.7	$10.3	$188.7
Waste	$0.7	$0.0	$0.9	$0.2	$0.4	$2.2
Unspecified	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total	**$162.0**	**$11.0**	**$145.5**	**$28.4**	**$31.7**	**$378.6**

Source: U.S. EPA analysis, 2002.

B7-1.2 Cost-to-Revenue Measure

a. Facility-level analysis

EPA estimates that the cost-to-revenue ratios at the facility-level for both analyzed cases of the waterbody/capacity-based option are low, similar to the proposed rule. Table B7-4 presents the distribution of facilities by range of the cost-to-revenue ratio, for both Option 1 and Option 2. Under both options, a vast majority of facilities incur compliance costs of less than one percent revenues. EPA estimates that under Option 1, 416 facilities, or 76 percent, would incur compliance costs of less than one percent of revenues; under Option 2, 444 facilities, or 81 percent, would incur compliance costs of less than one percent of revenues. Under Option 1, 67 facilities, or 12 percent, would incur compliance costs of greater than 3 percent of revenues. Fifty-one facilities, or 9 percent, would incur compliance costs of greater than 3 percent of revenues under Option 2. For both options, nine facilities are projected to be baseline closures and the revenues for one facility were unknown.

Table B7-4: Facility-Level Cost-to-Revenue Measure Waterbody/Capacity-Based Option

Annualized Cost-to-Revenue Ratio	All Track I (Option 1)		Track I and II (Option 2)	
	All Phase II	Percent of Total Phase II	All Phase II	Percent of Total Phase II
< 1.0 %	416	76%	444	81%
1.0 - 3.0%	57	10%	44	8%
> 3.0 %	67	12%	51	9%
Baseline Closure	9	2%	9	2%
n/a	1	0%	1	0%
Total[a]	**550**	**100%**	**550**	**100%**

[a] Individual numbers may not add up due to independent rounding.

Source: U.S. EPA analysis, 2002.

b. Firm-level analysis

Similar to the proposed rule, EPA estimates that the compliance costs for the waterbody/capacity-based option would also be low compared to firm-level revenues. Table B7-5 below summarizes the results of the cost-to-revenue measures by the domestic parent entity types. Under Option 1, 120 of the 131 unique parent entities that own the facilities subject to this rule would incur compliance costs of less than 1 percent of revenues; six entities would incur compliance costs of between 1 and 3 percent of revenues; three entities would incur compliance costs of greater than 3 percent of revenues; and two entities are projected to only own facilities that are baseline closures. Under Option 2, 101 entities would incur compliance costs of less than one percent of revenues; 14 entities would incur compliance costs of between 1 and 3 percent of revenues; and 14 entities would incur compliance costs of greater than 3 percent of revenues. Similar to Option 1, EPA estimates that two entities only own facilities that are baseline closures under Option 2.

Table B7-5: Firm-Level Cost-to-Revenue Measure Waterbody/Capacity-Based Option

Annualized Cost-to-Revenue Ratio	All Track I (Option 1)		Track I and II (Option 2)	
	All Phase II	Percent of Total Phase II	All Phase II	Percent of Total Phase II
< 1.0 %	120	92%	101	77%
1.0 - 3.0%	6	5%	14	11%
> 3.0 %	3	2%	14	11%
Baseline Closure	2	2%	2	2%
Total	**131**	**100%**	**131**	**100%**

Source: U.S. EPA analysis, 2002.

B7-1.3 SBREFA Analysis

The impacts on the small domestic parent entities would be very similar under both cases of the waterbody/capacity-based option, as presented in Table B7-6. Of the 28 entities EPA identified as small, 24 entities are expected to incur compliance costs of less than one percent of revenues under Option 1, and 25 entities under Option 2. EPA estimates that two entities would incur compliance costs of greater than 3 percent of revenues under Option 1. The cost-to-revenue ranges from 0.05 to 4.2 under Option 1. Under Option 2, only one entity is estimated to incur compliance costs of greater than 3 percent of revenues. The ratios range from 0.04 to 4.1 under this option.

Table B7-6: Impact Ratio Ranges by Small Entity Type
Waterbody/Capacity-Based Option

Type of Entity	All Track I (Option 1)					Track I and II (Option 2)				
	Impact Ratio Ranges	0-1%	1-3%	>3%	Total	Impact Ratio Ranges	0-1%	1-3%	>3%	Total
Municipality	0.2-4.2%	15	2	2	19	0.1-4.1%	16	2	1	19
Municipal Marketing Authority	0.05-0.1%	2	-	-	2	0.04-0.1%	2	-	-	2
Political Subdivision	0.6-0.6%	1	-	-	1	0.5-0.5%	1	-	-	1
Rural Electric Cooperative	0.1-0.4%	6	-	-	6	0.1-0.4%	6	-	-	6
Total	**0.05-4.2%**	**24**	**2**	**2**	**28**	**0.04-4.1%**	**25**	**2**	**1**	**28**

Source: U.S. EPA analysis, 2002.

B7-2 Impingement Mortality and Entrainment Controls Everywhere Option (Option 3a)

This option would require the implementation of technologies that reduce I&E at all Phase II facilities without regard to waterbody type and with no site-specific compliance option available. EPA would set technology-based performance requirements under this alternative but would not mandate the use of any specific technology. Unlike the proposed option, this alternative would not allow for the development of BTA on a site-specific basis (except on a best professional judgment basis). This alternative would not base requirements on the percent of source water withdrawn or restrict disruption of the natural thermal stratification of lakes or reservoirs. However, it would impose entrainment performance requirements on Phase II facilities located on freshwater rivers or streams, and lakes or reservoirs. Finally, under this alternative, restoration could be used, but only as a supplement to the use of design and construction technologies or operational measures. This alternative would establish clear performance-based requirements that are simpler and easier to implement than those proposed and are based on the use of available technologies to reduce AEI.

B7-2.1 Compliance Costs

The estimated total annualized private post-tax cost of compliance for the impingement mortality and entrainment controls everywhere option is approximately $195 million.

Table B7-7 presents the total annualized private compliance cost by cost category and NERC region. The annualized cost by NERC region ranges from approximately $76,000 for facilities located in ASCC (Alaska Systems Coordinating Council) to $45 million for facilities located in SERC (Southwestern Electric Reliability Council). The capital technology cost which includes the cost of fine-mesh traveling screens and fish handling and return systems comprises $135 million of the total $195 million cost (or 70 percent). The costs of operating and maintenance and permitting are approximately $32 and $29 million, respectively. The annual energy penalty and one-time connection outage costs are not applicable to this regulatory option

because no facilities will be required to reduce intake capacity commensurate with the use of a closed-cycle recirculating cooling system.

Table B7-7: Private (Post-Tax) Annualized Compliance Costs by NERC Region (in millions, $2001)
Impingement Mortality and Entrainment Controls Everywhere Option

NERC Region	One-Time Costs		Recurring Costs		Permitting Costs	Total
	Capital Technology	Connection Outage	O&M	Energy Penalty		
ASCC	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1
ECAR	$21.6	$0.0	$5.1	$0.0	$5.0	$31.7
ERCOT	$13.0	$0.0	$3.4	$0.0	$3.0	$19.3
FRCC	$8.0	$0.0	$2.0	$0.0	$1.8	$11.8
HI	$1.2	$0.0	$0.2	$0.0	$0.2	$1.6
MAAC	$10.5	$0.0	$2.1	$0.0	$2.2	$14.8
MAIN	$13.1	$0.0	$2.7	$0.0	$2.5	$18.3
MAPP	$5.6	$0.0	$1.3	$0.0	$2.5	$9.5
NPCC	$16.5	$0.0	$3.3	$0.0	$3.2	$23.0
SERC	$31.1	$0.0	$8.3	$0.0	$5.1	$44.5
SPP	$5.7	$0.0	$1.5	$0.0	$1.8	$8.9
WSCC	$8.4	$0.0	$1.6	$0.0	$1.9	$11.9
Total	**$134.6**	**$0.0**	**$31.6**	**$0.0**	**$29.2**	**$195.4**

Source: U.S. EPA analysis, 2002.

Table B7-8 presents total annual facility compliance costs by cost category and steam plant type. The annual compliance costs range from $900,000 for waste facilities to $96 million for coal facilities.

Table B7-8: Annualized Facility Compliance Costs by Steam Plant Type (in millions, $2001)
Impingement Mortality and Entrainment Controls Everywhere Option

Steam Plant Type	One-Time Costs		Recurring Costs		Permitting Costs	Total
	Capital Technology	Connection Outage	O&M	Energy Penalty		
Coal	$64.6	$0.0	$16.0	$0.0	$15.6	$96.2
Combined-Cycle	$2.2	$0.0	$0.6	$0.0	$0.9	$3.6
Nuclear	$28.3	$0.0	$5.8	$0.0	$2.9	$37.1
Oil/Gas	$39.1	$0.0	$9.1	$0.0	$9.4	$57.7
Waste	$0.3	$0.0	$0.1	$0.0	$0.4	$0.9
Unspecified	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total	**$134.6**	**$0.0**	**$31.6**	**$0.0**	**$29.2**	**$195.4**

Source: U.S. EPA analysis, 2002.

B7-2.2 Cost-to-Revenue Measure

a. Facility-level analysis

For the impingement mortality and entrainment controls everywhere option, EPA estimates that the compliance costs would be low compared to facility-level revenues. As shown in Table B7-9, out of the 550 in-scope facilities, 441 would incur annualized costs of less than one percent of revenues; 63 facilities would incur costs of between 1 and 3 percent; and 34 facilities would incur costs of greater than 3 percent. Eleven facilities are projected to be baseline closures, and for one facility, revenues are unknown.

Table B7-9: Facility-Level Cost-to-Revenue Measure Impingement Mortality and Entrainment Controls Everywhere Option

Annualized Cost-to-Revenue Ratio	All Phase II	Percent of Total Phase II
< 1.0 %	441	80%
1.0 - 3.0%	63	11%
> 3.0 %	34	6%
Baseline Closure	11	2%
n/a	1	0%
Total[a]	**550**	**100%**

[a] Individual numbers may not add up due to independent rounding.

Source: U.S. EPA analysis, 2002.

b. Firm-level analysis

Compliance costs for the impingement mortality and entrainment controls everywhere option would also be low compared to firm-level revenues. Of the 131 unique parent entities that own the facilities subject to this rule, 102 entities would incur compliance costs of less than 1 percent of revenues; 13 entities would incur compliance costs of between 1 and 3 percent of revenues; and 14 entities would incur compliance costs of greater than 3 percent of revenues. Under the impingement mortality and entrainment controls everywhere option, two entities own only facilities that are baseline closures. Table B7-10 summarizes these results.

Table B7-10: Firm-Level Cost-to-Revenue Measure Impingement Mortality and Entrainment Controls Everywhere Option

Annualized Cost-to-Revenue Ratio	All Phase II	Percent of Total Phase II
< 1.0%	102	78%
1.0 - 3.0%	13	10%
> 3.0 %	14	11%
Baseline Closure	2	2%
Total	**131**	**100%**

Source: U.S. EPA analysis, 2002.

B7-2.3 SBREFA Analysis

Under the impingement mortality and entrainment controls everywhere option, the overall annualized compliance costs that facilities owned by small entities are estimated to incur represent between 0.04 and 12.98 percent of the entities' annual sales revenues. Table B7-11 presents the distribution of the entities' cost-to-revenue ratios by small entity type. Of the 28 small entities, two would incur compliance costs of greater than three percent of revenues. Both of these entities are municipalities. Five entities would incur compliance costs of between one and three percent of revenues, while the remaining 21 entities would incur compliance costs of less than one percent of revenues.

Table B7-11: Impact Ratio Ranges by Small Entity Type
Impingement Mortality and Entrainment Controls Everywhere Option

Type of Entity	Impact Ratio Ranges	0-1%	1-3%	>3%	Total
Municipality	0.1-13%	12	5	2	19
Municipal Marketing Authority	0.04-0.3%	2	-	-	2
Political Subdivision	0.1-0.1%	1	-	-	1
Rural Electric Cooperative	0.1-0.6%	6	-	-	6
Total	**0.04-12.98%**	**21**	**5**	**2**	**28**

Source: U.S. EPA analysis, 2002.

B7-3 ALL COOLING TOWERS OPTION (OPTION 4)

This option would require all Phase II facilities having a design intake flow of 50 million gallons per day (MGD) or more to reduce the total design intake flow to a level, at a minimum, commensurate with that which can be attained by a closed-cycle recirculating cooling system. Of the 550 Phase II facilities, 124 already have a recirculating wet cooling system (e.g., wet cooling towers or ponds). These facilities would meet the requirements under this option unless they are located in areas where the director or fisheries managers determine that fisheries need additional protection. Therefore, under this option, 426 steam electric power generating facilities would be required to meet performance standards for reducing impingement mortality and entrainment based on a reduction in intake flow to a level commensurate with that which can be attained by a closed-cycle recirculating system.

B7-3.1 Compliance Costs

EPA estimates that the total annualized private post-tax cost of compliance for the all cooling towers option is approximately $2.32 billion. According to EPA's unit cost estimates, capital costs for individual high-flow plants to convert to wet towers generally ranged from $130 million to $200 million, with annual operating costs in the range of $4 million to $20 million.

Table B7-12 presents private annualized facility compliance costs by cost category and NERC region. The annualized cost by NERC region ranges from approximately $1 million for facilities located in ASCC (Alaska Systems Coordinating Council) to $660 million for facilities located in SERC (Southwestern Electric Reliability Council). The largest cost component would be the annual operating and maintenance expense which represents $1.1 billion (or 47 percent) of the total cost. EPA estimates the capital technology cost to be $685 million (or 30 percent) of the total cost. The energy effects associated with the installation of cooling towers would be $124 million (or 5 percent) for the connection outage and $362 million (or 16 percent) for the recurring energy penalty. The permitting costs are estimated to be $29 million (or 1 percent) of the total cost. The permitting costs under this regulatory option would be relatively low since the technology requirements would not include extensive site-specific determinations on the part of complying facilities.

Table B7-12: Annualized Facility Compliance Costs by NERC Region (in millions, $2001)
All Cooling Towers Option

NERC Region	One-Time Costs		Recurring Costs		Permitting Costs	Total
	Capital Technology	Connection Outage	O&M	Energy Penalty		
ASCC	$0.4	$0.0	$0.4	$0.1	$0.1	$1.0
ECAR	$106.8	$13.4	$183.4	$52.0	$5.0	$360.6
ERCOT	$58.6	$11.5	$114.0	$34.4	$3.0	$221.5
FRCC	$43.2	$7.4	$74.7	$23.4	$1.8	$150.4
HI	$6.2	$1.1	$6.3	$2.6	$0.2	$16.5
MAAC	$59.5	$6.7	$78.7	$19.2	$2.2	$166.3
MAIN	$53.3	$6.0	$80.6	$20.5	$2.5	$162.8
MAPP	$32.7	$4.8	$54.4	$15.0	$2.5	$109.5
NPCC	$99.0	$10.7	$143.6	$30.8	$3.2	$287.3
SERC	$165.3	$51.9	$299.9	$137.8	$5.1	$660.0
SPP	$13.8	$1.3	$26.4	$5.8	$1.8	$49.1
WSCC	$45.9	$8.8	$54.4	$20.4	$1.9	$131.5
Total	**$684.7**	**$123.8**	**$1,116.7**	**$361.9**	**$29.2**	**$2,316.4**

Source: U.S. EPA analysis, 2002.

Table B7-13 presents total annual facility compliance costs by cost category and steam plant type. The annual compliance costs range from $5 million for waste facilities to $1.2 billion for coal facilities.

Table B7-13: Annualized Facility Compliance Costs by Steam Plant Type (in millions, $2001)
All Cooling Towers Option

Steam Plant Type	One-Time Costs		Recurring Costs		Permitting Costs	Total
	Capital Technology	Connection Outage	O&M	Energy Penalty		
Coal	$319.7	$62.7	$575.7	$200.6	$15.6	$1,174.3
Combined-Cycle	$10.5	$0.9	$17.0	$1.8	$0.9	$31.1
Nuclear	$166.8	$45.6	$199.3	$94.4	$2.9	$509.0
Oil/Gas	$184.9	$14.7	$318.8	$64.6	$9.4	$592.4
Waste	$1.5	$0.0	$2.3	$0.5	$0.4	$4.7
Unspecified	$1.3	$0.0	$3.6	$0.0	$0.0	$4.9
Total	**$684.7**	**$123.8**	**$1,116.7**	**$361.9**	**$29.2**	**$2,316.4**

Source: U.S. EPA analysis, 2002.

B7-3.2 Cost-to-Revenue Measure

a. Facility-level analysis

The facility-level costs-to-revenue analysis for the all cooling towers option is presented below. The all cooling towers option results in high cost-to-revenue ratios at the facility level. This is not unexpected since under this option all in-scope facilities are required to reduce their intake capacity with the use of closed-cycle recirculating cooling systems. As shown below in Table B7-14, over 50 percent of the facilities would incur compliance costs of greater than 3 percent of revenues under this option. Two-hundred forty-one facilities, or 44 percent, would incur compliance costs of less than 3 percent of revenues. Nine facilities are projected to be baseline closures, and the revenues for one facility remain unknown.

Table B7-14: Facility-Level Cost-to-Revenue Measure All Cooling Towers Option

Annualized Cost-to-Revenue Ratio	All Phase II	Percent of Total Phase II
< 1.0 %	104	19%
1.0 - 3.0%	137	25%
> 3.0 %	298	54%
Baseline Closure	9	2%
n/a	1	0%
Total[a]	**550**	**100%**

[a] Individual numbers may not add up due to independent rounding.

Source: U.S. EPA analysis, 2002.

b. Firm-level analysis

Similar to the facility-level impacts, the cost-to-revenue ratios at the firm-level would also be high under the all cooling towers option. Thirty-six of the 131 unique domestic-parent entities would incur compliance costs of greater than 3 percent of revenues. The remaining 93 entities would incur compliance costs of less than 3 percent of revenues. Two of the entities own only facilities that are baseline closures under the all cooling towers option.

Table B7-15: Firm-Level Cost-to-Revenue Measure All Cooling Towers Option

Annualized Cost-to-Revenue Ratio	All Phase II	Percent of Total Phase II
< 1.0 %	73	56%
1.0 - 3.0%	20	15%
> 3.0 %	36	27%
Baseline Closure	2	2%
Total	**131**	**100%**

Source: U.S. EPA analysis, 2002.

B7-3.3 SBREFA Analysis

Under the all cooling towers option, EPA estimates that the 28 small entities would incur compliance costs of 0.05 percent to 33.63 percent of revenues. Over 46 percent, or 13 entities, would incur compliance costs of greater than 3 percent of revenues under the all cooling towers option. Eleven of these entities are municipalities. Table B7-16 presents the distribution of small entities by their entity type and estimated impact ratios under the all cooling towers option.

Table B7-16: Impact Ratio Ranges by Small Entity Type All Cooling Towers Option

Type of Entity	Impact Ratio Ranges	0-1%	1-3%	>3%	Total
Municipality	0.2-33.6%	4	4	11	19
Municipal Marketing Authority	0.1-2.4%	1	1	-	2
Political Subdivision	0.5-0.5%	1	-	-	1
Rural Electric Cooperative	0.1-5.9%	1	3	2	6
Total	**0.05-33.63%**	**7**	**8**	**13**	**28**

Source: U.S. EPA analysis, 2002.

B7-4 Dry Cooling Option (Option 5)

The dry cooling option requires all facilities that would install a cooling tower under the waterbody/capacity-based option to reduce their intake capacity to a level commensurate with the use of a dry cooling system.

B7-4.1 Compliance Costs

EPA estimates that the total annualized private post-tax cost of compliance with the dry cooling option is approximately $1.25 billion.

Table B7-17 presents private annualized facility compliance costs by cost category and NERC region for the dry cooling option. The annualized cost by NERC region ranges from approximately $0.1 million for facilities located in ASCC (Alaska Systems Coordinating Council) to $269 million for facilities located in FRCC (Florida Reliability Coordinating Council). The largest cost component would be the annual energy penalty associated with the dry cooling technology, which represents $554 million (or 44 percent) of the total cost. The dry cooling technology causes a reduction in unit efficiency due to increased turbine back-pressure of between 1.0 and 10.1 percent depending on the geographic region and generator type (for more detailed information on EPA's estimate of energy penalties see *Chapter B1: Summary of Compliance Costs*). EPA estimates the annualized capital technology cost and the annual operating and maintenance cost to be $490 million (or 39 percent) and $156 million (or 12 percent of total costs), respectively. The monthly connection outage and permitting costs are both estimated to be $26 million (or 2 percent of the total compliance costs).

Table B7-17: Annualized Facility Compliance Costs by NERC Region (in millions, $2001)
Dry Cooling Option

NERC Region	One-Time Costs		Recurring Costs		Permitting Costs	Total
	Capital Technology	Connection Outage	O&M	Energy Penalty		
ASCC	$0.0	$0.0	$0.0	$0.0	$0.1	$0.1
ECAR	$15.2	$0.0	$3.6	$0.0	$5.0	$23.7
ERCOT	$17.2	$0.4	$7.9	$29.4	$2.7	$57.5
FRCC	$73.9	$5.4	$27.0	$160.8	$1.5	$268.5
HI	$14.3	$1.1	$3.3	$27.7	$0.1	$46.4
MAAC	$94.6	$3.2	$29.7	$49.3	$1.7	$178.5
MAIN	$6.4	$0.0	$1.4	$0.0	$2.5	$10.3
MAPP	$2.0	$0.0	$0.4	$0.0	$2.5	$4.9
NPCC	$134.4	$4.6	$41.0	$73.4	$2.3	$255.7
SERC	$51.1	$3.5	$19.5	$105.3	$4.8	$184.2
SPP	$1.3	$0.0	$0.4	$0.0	$1.8	$3.5
WSCC	$80.0	$7.3	$22.2	$107.8	$1.4	$218.6
Total	**$490.4**	**$25.5**	**$156.3**	**$553.6**	**$26.3**	**$1,252.0**

Source: U.S. EPA analysis, 2002.

Table B7-18 presents total annual facility compliance costs by cost category and steam plant type. The annual compliance costs range from $3 million for waste facilities to $464 million for oil and gas facilities.

Table B7-18: Annualized Facility Compliance Costs by Steam Plant Type (in millions, $2001)
Dry Cooling Option

Steam Plant Type	One-Time Costs		Recurring Costs		Permitting Costs	Total
	Capital Technology	Connection Outage	O&M	Energy Penalty		
Coal	$118.8	$5.3	$38.4	$153.3	$15.0	$330.7
Combined-Cycle	$18.2	$0.4	$6.5	$13.0	$0.7	$38.9
Nuclear	$144.4	$14.3	$43.7	$210.2	$2.3	$414.9
Oil/Gas	$207.6	$5.4	$67.0	$176.2	$7.9	$464.1
Waste	$1.4	$0.0	$0.7	$0.9	$0.3	$3.3
Unspecified	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total	**$490.4**	**$25.5**	**$156.3**	**$553.6**	**$26.3**	**$1,252.0**

Source: U.S. EPA analysis, 2002.

B7-4.2 Cost-to-Revenue Measure

a. Facility-level analysis

The annualized cost-to-revenue ratios at the facility level for the dry cooling option are presented in Table B7-19. The ratios are higher under the dry cooling option than for the proposed rule. Of the 550 in-scope facilities, 73 facilities are expected to incur compliance costs of greater than 3 percent of revenues; 41 facilities would incur compliance costs of between 1 and 3 percent of revenues; and 425 facilities would incur compliance costs of less than one percent of revenues. Nine of the facilities are expected to be baseline closures, and the revenues for one facility remain unknown.

Table B7-19: Facility-Level Cost-to-Revenue Measure Dry Cooling Option

Annualized Cost-to-Revenue Ratio	All Phase II	Percent of Total Phase II
< 1%	425	77%
1.0 - 3.0%	41	7%
> 3.0 %	73	13%
Baseline Closure	9	2%
n/a	1	0%
Total[a]	**550**	**100%**

[a] Individual numbers may not add up due to independent rounding.

Source: U.S. EPA analysis, 2002.

b. Firm-level analysis

Impacts incurred at the firm level are similar to the facility-level impacts for the dry cooling option. EPA estimates 17 of the 131 unique domestic parent entities, or 13 percent, would incur compliance costs of greater than 3 percent of revenues. The remaining 112 entities would incur compliance costs of less than 3 percent of revenues under this option. Under the dry cooling option, two entities own only baseline closure facilities.

Table B7-20: Firm-Level Cost-to-Revenue Measure Dry Cooling Option

Annualized Cost-to-Revenue Ratio	All Phase II	Percent of Total Phase II
<1 %	95	73%
1.0 - 3.0%	17	13%
> 3.0 %	17	13%
Baseline Closure	2	2%
Total	**131**	**100%**

Source: U.S. EPA analysis, 2002.

B7-4.3 SBREFA Analysis

Under the dry cooling option, EPA estimates that the impacts on small entities would be minimal. Only one of the 28 entities determined to be small would incur compliance costs of greater than three percent of revenues. This one entity is a municipality. The remaining 27 small entities would incur compliance costs of less than three percent of revenues under the dry cooling option. The impact ratio ranges by small entity type for the dry cooling option are presented in Table B7-21.

Table B7-21: Impact Ratio Ranges by Small Entity Type Dry Cooling Option

Type of Entity	Impact Ratio Ranges	0-1%	1-3%	>3%	Total
Municipality	0.1-4.1%	16	2	1	19
Municipal Marketing Authority	0.04-0.1%	2	-	-	2
Political Subdivision	0.5-0.5%	1	-	-	1
Rural Electric Cooperative	0.1-0.4%	6	-	-	6
Total	**0.04-4.1%**	**25**	**2**	**1**	**28**

Source: U.S. EPA analysis, 2002.

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Chapter B8: Alternative Options - Electricity Market Model Analysis

INTRODUCTION

Chapter B7: Alternative Options - Costs and Economic Impacts described the total costs and economic impacts of four of the six alternative regulatory options considered by EPA. This chapter presents EPA's electricity market model analysis using ICF Consulting's Integrated Planning Model (IPM®) for two of those alternative options: (1) the waterbody/capacity-based option (Option 1), and (2) the all cooling towers option (Option 4).

CHAPTER CONTENTS

B8-1 OVERVIEW OF IPM ANALYSIS OF ALTERNATIVE OPTIONS

EPA used the IPM, an integrated energy market model, to analyze two potential effects of the alternative regulatory options: (1) potential energy effects at the national and regional levels, as required by Executive Order 13211 ("Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use"); and (2) potential economic impacts on in-scope facilities.[1] Both alternative options analyzed using the IPM have more stringent compliance technology requirements than the proposed rule. Specifically, both options would require a subset of existing facilities to install recirculating wet cooling towers.

Table B8-1 below presents the number and capacity of facilities in each NERC region that EPA estimated would install a cooling tower under the waterbody/capacity-based option and the all cooling towers option, respectively. The table presents the percentage of total pre-run capacity in each region that was costed with a cooling tower under the two alternative options. Pre-run capacity is defined as the current operating, and planned-committed generating units, as identified by ICF. It is used for this measure, rather than the base case capacity. Since the base case results reflect a post-compliance landscape in which the effects of cooling tower installation are already modeled, the base case would no longer provide a useful measure of the magnitude of capacity effected by the alternative options. [2]

[1] *Chapter B3: Electricity Market Model Analysis* presents a detailed description of the IPM and a discussion of the methodology EPA used to estimate economic impacts using the IPM.

[2] Note that of the 539 surveyed facilities subject to the section 316(b) Phase II Rule, nine are not modeled in the IPM. Three facilities are in Hawaii, one is in Alaska. Neither state is represented in the IPM. One facility is identified as an "Unspecified Resource" and does not report on any EIA forms. Four facilities are on-site facilities that do not provide electricity to the grid. The 530 in-scope facilities modeled by the IPM were weighted to account for facilities not sampled and facilities that did not respond to the EPA's industry survey and thus represent a total of 540 facilities industry-wide. The results for Phase II facilities in the remainder of this chapter, except where noted, are based on the 540 weighted facilities.

Table B8-1: Distribution of Cooling Towers in 2008 (MW; by NERC Region)[a, b]

NERC Region	National Pre-Run Capacity	Waterbody/Capacity-Based Option			All Cooling Towers Option		
		# of Facilities	Pre - Run Capacity	% of Pre-Run Capacity	# of Facilities	Pre-Run Capacity	% of Pre-Run Capacity
ECAR	124,220	0	0	0.0%	77	54,200	43.6%
ERCOT	79,590	4	3,840	4.8%	35	30,650	38.5%
FRCC	53,680	7	8,970	16.7%	23	18,320	34.1%
MAAC	67,350	9	9,320	13.8%	26	19,480	28.9%
MAIN	67,520	0	0	0.0%	40	27,350	40.5%
MAPP	39,120	0	0	0.0%	39	14,790	37.8%
NPCC	81,070	18	13,530	16.7%	58	35,840	44.2%
SERC	205,310	5	7,390	3.6%	76	84,590	41.2%
SPP	51,340	0	0	0.0%	18	7,450	14.5%
WSCC	172,790	9	12,200	7.1%	24	19,470	11.3%
Total	**941,990**	**52**	**55,250**	**5.9%**	**416**	**312,140**	**33.1%**

[a] Capacities have been rounded to the nearest 10, and percentages have been rounded to the nearest 10th.
[b] The number of facilities and pre-run capacity under each option have been weighted to account for facilities not sampled and facilities that did not respond to the EPA's industry survey.

Source: IPM analysis: Section 316(b) Base Case 2000, EPA Analysis 2002.

Waterbody/capacity-based option: Overall, EPA estimates that 54 facilities would install a cooling tower under this option. Two of these facilities are located in Hawaii, and are therefore not included in the IPM analysis. Table B8-1 shows that 52 facilities in six NERC regions are estimated to be required to install wet cooling towers under this option. In aggregate, these facilities account for 55,250 MW of capacity or 5.9 percent of the total pre-run capacity. Three regions (FRCC, MAAC, and NPCC) would be required to install cooling towers on more than 13 percent of total base case capacity.

All cooling towers option: Overall, EPA estimates that 426 facilities would install a cooling tower under this option. Ten of these facilities are not modeled. In total, 416 facilities across all regions are estimated to install wet cooling towers under this option, accounting for 312,140 MW of capacity or 33.1 percent of total pre-run capacity. EPA estimates that at least 10 percent of capacity in each region would install cooling towers under this option, and four of the 10 regions would install cooling towers on more than 40 percent of total base case capacity. ECAR would install cooling towers on the largest number of facilities (77), and the second largest percentage of capacity (43.6 percent).

B8-2 Market Analysis

This section presents the results of the IPM analysis for all facilities modeled by the IPM. The results in this section include facilities that are in-scope and facilities that are out-of-scope of the proposed Phase II rule. Market level impacts associated with each of the alternative options are assessed using the following seven impact measures: (1) plant closures, (2) capacity changes, (3) generation changes, (4) revenue changes, (5) variable production cost changes, (6) fuel cost changes, and (7) electricity price changes.[3] These measures were developed for model run year 2013.[4] A detailed description of each of the impact measures discussed below is presented in Section B3-3.1 of *Chapter B3: Electricity Market Model Analysis*.

[3] All of the information presented in section B8-2 is unweighted.

[4] The IPM model simulates electricity market function for a period of 25 years. Model output is provided for five user-specified model run years. EPA selected three run years to provide output across the ten year compliance period for the rule. Analyses of regulatory options are based on output for model run years that reflect a scenario in which all facilities are operating in their post-compliance condition. Options requiring the installation of cooling towers are analyzed using output from model run year 2013.

a. Market plant closures

Table B8-2 presents total base case capacity as well as the capacity of plant closures and the percentage of total base case capacity closed under the two alternative options by NERC region.

Table B8-2: National Capacity of Closure Units by 2013 (MW; by NERC Region)[a]

NERC Region	Base Case Capacity	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Closure Capacity	% of Base Case	Closure Capacity	% of Base Case
ECAR	122,080	0	0.0%	110	0.1%
ERCOT	80,230	0	0.0%	460	0.6%
FRCC	52,850	0	0.0%	90	0.2%
MAAC	65,270	0	0.0%	(40)	-0.1%
MAIN	61,380	0	0.0%	0	0.0%
MAPP	36,660	0	0.0%	0	0.0%
NPCC	74,080	840	1.1%	800	1.1%
SERC	205,210	0	0.0%	(170)	-0.1%
SPP	51,380	0	0.0%	20	0.0%
WSCC	173,600	2,170	1.3%	2,370	1.4%
Total	**922,740**	**3,010**	**0.3%**	**3,640**	**0.4%**

[a] Capacities have been rounded to the nearest 10 and percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: In aggregate, 0.3 percent of total base case capacity closes as a result of this option. Two regions, NPCC and WSCC, experience closures of existing capacity. Of the 840 MW of capacity that closes in NPCC (1.1 percent of total base case capacity), 440 MW is oil/gas fired capacity while the remaining 400 MW is nuclear capacity. In WSCC 2,170 MW of capacity, or 1.3% of the total capacity in the region closes. The vast majority of this capacity, 99 percent (2,150 MW), represents nuclear capacity.

All cooling towers option: Overall, 0.4 percent of total base case capacity closes under this option. Six regions experience closures of existing capacity. Of the 3,640 MW of total capacity that closes under this option, 2,370 MW (65 percent) occur in WSCC. This closure represents 1.4 percent of total base case capacity in WSCC. Conversely, two regions, MAAC and SERC, experience avoided closures as a result of this option. In these regions, facilities that would have closed in the absence of section 316(b) regulation remain open under this option. This could occur as a result of increases in electricity prices, which could increase the number of plants that can profitably supply generation, or if a facility's compliance costs are low relative to other affected facilities.

b. Market capacity

❖ *Total domestic capacity*

Table B8-3 presents the total domestic capacity under the base case and the two alternative regulatory options by NERC region. The total domestic capacity shows the effects of closures, additions, repowerings, and energy penalties. The change in capacity associated with each option is expressed as a percentage of total base case capacity.

Table B8-3: National Domestic Capacity in 2013 (MW; by NERC Region)[a]

NERC Region	Base Case Capacity	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Capacity	% Change	Capacity	% Change
ECAR	122,080	122,260	0.1%	121,330	-0.6%
ERCOT	80,230	80,160	-0.1%	79,820	-0.5%
FRCC	52,850	52,710	-0.3%	52,580	-0.5%
MAAC	65,270	65,170	-0.2%	65,050	-0.3%
MAIN	61,380	61,380	0.0%	61,100	-0.5%
MAPP	36,660	36,640	-0.1%	36,410	-0.7%
NPCC	74,080	73,840	-0.3%	73,650	-0.6%
SERC	205,210	204,970	-0.1%	204,820	-0.2%
SPP	51,380	51,360	0.0%	51,320	-0.1%
WSCC	173,600	173,450	-0.1%	173,280	-0.2%
Total	**922,740**	**921,940**	**-0.1%**	**919,360**	**-0.4%**

[a] Capacities have been rounded to the nearest 10, and percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: Overall, there is a reduction in total available capacity of approximately 800 MW, or 0.1 percent of total base case capacity. Therefore, this option would be considered a significant energy action under Executive Order 13211, and EPA would be required to prepare a Statement of Energy Effects if the Agency proposed this regulatory option. The largest percentage decrease in capacity occurs in FRCC and NPCC with 0.3 percent of base case capacity. In all other regions, the capacity reduction is less than 0.2 percent.

All cooling towers option: In aggregate, there is a reduction in total available capacity of approximately 3,380 MW, or 0.4 percent of total base case capacity. Therefore, this option would also be considered a significant energy action, and EPA would be required to prepare a Statement of Energy Effects if the Agency proposed this regulatory option. The largest percentage decrease in capacity occurs in MAPP with 0.7 percent of base case capacity.

❖ *Capacity additions*

Table B8-4 presents the total base case capacity as well as the total cumulative capacity additions through 2013, under the base case and both alternative options by NERC region. For each of these three scenarios, total capacity additions for each region is expressed as a percentage of total base case capacity. Finally, the difference between capacity additions as a percentage of total base case capacity for the two regulatory options and base case capacity additions as a percentage of total base case capacity is calculated and presented in bold.

Table B8-4: National Domestic Capacity Additions in 2013 (MW; by NERC Region)[a]

NERC Region	Base Case Total Capacity	Base Case Capacity Additions	Additions as a % of Total Base Case Capacity	Waterbody/Capacity-Based Option			All Cooling Towers Option		
				Capacity Additions	Additions as a % of Total Base Case Capacity	Difference	Capacity Additions	Additions as a % of Total Base Case Capacity	Difference
ECAR	122,080	12,030	9.9%	12,210	10.0%	**0.1%**	14,400	11.8%	**1.9%**
ERCOT	80,230	6,990	8.7%	6,980	8.7%	**0.0%**	7,280	9.1%	**0.4%**
FRCC	52,850	13,600	25.7%	13,590	25.7%	**0.0%**	13,670	25.9%	**0.1%**
MAAC	65,270	7,290	11.2%	7,330	11.2%	**0.1%**	7,350	11.3%	**0.1%**
MAIN	61,380	10,750	17.5%	10,740	17.5%	**0.0%**	11,320	18.4%	**0.9%**
MAPP	36,660	3,980	10.9%	3,960	10.8%	**-0.1%**	3,920	10.7%	**-0.2%**
NPCC	74,080	7,030	9.5%	8,070	10.9%	**1.4%**	8,590	11.6%	**2.1%**
SERC	205,210	40,660	19.8%	40,520	19.7%	**-0.1%**	41,520	20.2%	**0.4%**
SPP	51,380	2,420	4.7%	2,410	4.7%	**0.0%**	2,520	4.9%	**0.2%**
WSCC	173,600	14,120	8.1%	15,340	8.8%	**0.7%**	15,420	8.9%	**0.7%**
Total	**922,740**	**118,870**	**12.9%**	**121,150**	**13.1%**	**0.2%**	**125,990**	**13.7%**	**0.8%**

[a] Capacities have been rounded to the nearest 10, and percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: In total, capacity additions as a percentage of base case capacity increases by 0.2 percent under this option as compared to the base case. The two largest increases in this metric occur in NPCC and WSCC, with increases of 1.4 percent and 0.7 percent, respectively. These increases occur in part due to the closures that are experienced under this option. MAPP and SERC experience decreases in capacity additions as a percentage of base case capacity.

All cooling towers option: Overall, capacity additions as a percentage of base case capacity increase by 0.8 percent under the all cooling tower option as compared to the base case. As was the case under the waterbody/capacity-based option, the largest increase in this metric occurs in NPCC (2.1 percent). MAPP experiences a decrease in capacity additions as a percentage of base case capacity of 0.2 percent.

❖ *Repowering capacity*

Table B8-5 presents the total base case capacity as well as total repowered capacity under the base case and both alternative options by NERC region. For each of the three scenarios total repowered capacity for each region is expressed as a percentage of total base case capacity. Finally, the difference between repowered capacity as a percentage of total base case capacity for the two regulatory options and the base case repowered capacity as a percentage of total base case capacity is calculated and presented in bold.

Table B8-5: National Repowering Capacity in 2013 (MW; by NERC Region)[a]

NERC Region	Base Case Total Capacity	Base Case Repowered Capacity	Repowering as a % of Total Base Case Capacity	Waterbody/Capacity-Based Option			All Cooling Towers Option		
				Repowered Capacity	Repowering as a % of Total Base Case Capacity	Difference	Repowered Capacity	Repowering as a % of Total Base Case Capacity	Difference
ECAR	122,080	0	0.0%	0	0.0%	**0.0%**	0	0.0%	**0.0%**
ERCOT	80,230	1,390	1.7%	1,410	1.8%	**0.0%**	5,510	6.9%	**5.1%**
FRCC	52,850	0	0.0%	0	0.0%	**0.0%**	0	0.0%	**0.0%**
MAAC	65,270	1,660	2.5%	1,640	2.5%	**0.0%**	1,640	2.5%	**0.0%**
MAIN	61,380	0	0.0%	0	0.0%	**0.0%**	0	0.0%	**0.0%**
MAPP	36,660	0	0.0%	0	0.0%	**0.0%**	0	0.0%	**0.0%**
NPCC	74,080	8,460	11.4%	7,900	10.7%	**-0.8%**	7,730	10.4%	**-1.0%**
SERC	205,210	0	0.0%	0	0.0%	**0.0%**	0	0.0%	**0.0%**
SPP	51,380	0	0.0%	0	0.0%	**0.0%**	0	0.0%	**0.0%**
WSCC	173,600	7,020	4.0%	8,960	5.2%	**1.1%**	7,770	4.5%	**0.4%**
Total	**922,740**	**18,530**	**2.0%**	**19,910**	**2.2%**	**0.2%**	**22,650**	**2.5%**	**0.4%**

[a] Capacities have been rounded to the nearest 10, and percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: In aggregate, this option results in a 0.2 percent increase(450 MW) in repowered capacity as a percentage of total base case capacity relative to the base case. Existing facilities in four NERC regions experience repowering: WSCC, NPCC, MAAC and ERCOT. Of the 19,910 MW of repowered capacity, 8,960 MW, or 45 percent, is located in WSCC. This region also experiences the largest change in repowered capacity as a percentage of total base case capacity, increasing by 1.1 percent. NPCC experiences the second largest absolute amount of repowered capacity with 7,900 MW. However, this represents a 0.8 percent decrease compared to the base case.

All cooling towers option: Overall, repowered capacity as a percentage of total base case capacity increases by 0.4 percent under this option as compared to the base case. ERCOT experiences the largest change in this metric, increasing 5.1 percent. As was the case under the waterbody/capacity-based option, WSCC and NPCC are responsible for the majority (68 percent) of the repowered capacity under this option.

c. Market generation

Table B8-6 presents total generation under the base case and the two alternative regulatory options by NERC region. Total generation associated with each option is expressed as a percentage of total base case generation. The IPM model, as specified for this analysis, does not capture changes in demand that may result from electricity price increases associated with each of the regulatory options.[5]

Table B8-6: National Generation in 2013 (million MWh; by NERC Region)[a]

NERC Region	Base Case Generation	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Generation	% Change	Generation	% Change
ECAR	661	661	0.0%	660	-0.2%
ERCOT	360	360	0.0%	360	0.0%
FRCC	199	199	0.0%	199	0.0%
MAAC	284	284	-0.2%	288	1.1%
MAIN	286	286	0.3%	285	-0.3%
MAPP	187	187	0.0%	186	-0.3%
NPCC	285	285	-0.1%	284	-0.7%
SERC	987	987	0.0%	988	0.0%
SPP	228	228	0.0%	229	0.4%
WSCC	784	784	0.0%	784	0.0%
Total	**4,261**	**4,261**	**0.0%**	**4,261**	**0.0%**

[a] Percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: While there is no change in total generation under this option, there is a minor redistribution of generation among regions. The largest increase in generation occurs in MAIN, at 0.3 percent while MAAC experiences a decrease of 0.2 percent.

All cooling towers option: While there is no change in total generation under this option, there is a redistribution of generation among regions. MAAC experiences a 1.1 percent increase in total generation while NPCC experiences a decrease of 0.7 percent.

[5] Section B3-6 of *Chapter B3: Electricity Market Model Analysis* presents a detailed discussion of this assumption.

d. Market revenues

Table B8-7 presents the base case revenues, as well as total revenues under the each of the alternative options and the percent change in revenues between the base case and the two alternative options by NERC region.

Table B8-7: National Revenues in 2013 (in millions, $2001; by NERC Region)[a]

NERC Region	Base Case Revenues	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Revenues	% Change	Revenues	% Change
ECAR	22,180	22,190	0.0%	22,440	1.2%
ERCOT	12,060	12,060	0.0%	12,090	0.2%
FRCC	7,840	7,820	-0.3%	7,810	-0.4%
MAAC	10,960	10,940	-0.2%	11,070	1.0%
MAIN	9,960	9,980	0.2%	10,000	0.4%
MAPP	5,960	5,960	0.0%	5,990	0.5%
NPCC	11,020	11,280	2.4%	11,330	2.8%
SERC	34,360	34,360	0.0%	34,450	0.3%
SPP	7,750	7,750	0.0%	7,770	0.3%
WSCC	24,840	24,890	0.2%	24,880	0.2%
Total	**146,930**	**147,230**	**0.2%**	**147,830**	**0.6%**

[a] Revenues have been rounded to the nearest 10, and percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: In aggregate, total revenues increase by 0.2 percent under this option. Since generation is fixed, the overall increase in revenues is due price increases (Tables B8-10 and B8-11). Five of the ten regions experience a change in this metric. The largest change in revenues occurs in NPCC, which experiences an increase of 2.4 percent. As generation would remain virtually unchanged in this region, the increase in capacity prices presented in Table B8-11 is the most likely explanation for this increase in revenues. The largest decrease in revenues, 0.3 percent, occurs in FRCC. With stable generation and an increase in energy price in this region, this reduction is caused by the decrease in capacity prices (see Table B8-11).

All cooling towers option: Overall, this option results in a 0.6 percent increase in total revenues. As is the case under the waterbody/capacity-based option, the largest increase (2.8 percent) occurs in NPCC, while the only decrease (0.4 percent) occurs in FRCC. The results presented in Table B8-11 suggest that changes in capacity prices are likely be responsible for these changes in revenues.

e. Market variable production costs

Table B8-8 presents the variable production costs for the base case as well as production costs and percentage change in base case production costs under each of the two alternative regulatory options by NERC region. Variable production costs include fuel and other variable O&M costs and are the primary determinant of when and how often a plant's generation units are dispatched.

Table B8-8: National Variable Production Costs/MWh Generation in 2013 (in millions, $2001; by NERC Region)[a]

NERC Region	Base Case Production Costs	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Production Costs	% Change	Production Costs	% Change
ECAR	11.90	11.90	0.0%	12.19	2.4%
ERCOT	17.27	17.27	0.0%	17.33	0.3%
FRCC	18.17	18.25	0.4%	18.31	0.7%
MAAC	13.06	13.15	0.7%	13.29	1.8%
MAIN	12.22	12.25	0.2%	12.50	2.3%
MAPP	11.20	11.20	0.0%	11.32	1.0%
NPCC	17.88	17.98	0.5%	18.07	1.0%
SERC	12.73	12.74	0.1%	12.89	1.2%
SPP	13.63	13.63	0.0%	13.70	0.5%
WSCC	11.66	11.89	1.9%	11.89	1.9%

[a] Percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: This option increases variable production costs in six of the ten NERC regions under this option while remaining unchanged in the other four. The largest increase in variable production costs occurs in WSCC, which experiences a 1.9 percent increase. The most likely cause for this increase is the economic closure of 2,170 MW of existing capacity that occurs in this region (see Table B8-2). Of the total closures in this region, 2,150 MW comes from nuclear capacity, a low-cost source of generation. Although new capacity comes online in the form of capacity additions and repowerings (see Tables B8-4 and B8-5), the new capacity is in the form of combined-cycle and combustion turbine capacity, prime movers that have higher average variable production costs than the existing nuclear capacity being replaced. As a result, the average production cost per MWh of generation for the region increases.

Only two other NERC regions experience an increase in production costs of 0.5 percent or more, MAAC and NPCC, with increases of 0.7 percent and 0.5 percent respectively. These increases could be associated with an increase in variable O&M costs at facilities that are estimated to install recirculating wet cooling towers under this option. As shown in Table B8-1, a relatively high percentage of base case capacity in these regions are required to install recirculating wet cooling towers under this option.

All cooling towers option: This option increases variable production costs per MWh of generation in each of the ten NERC regions with seven regions experiencing increases of 1 percent or more. The two largest impacts in this measure occur in ECAR and MAIN, where the production costs increase by 2.4 percent and 2.3 percent, respectively. This result is not surprising given that approximately 40 to 45 percent of base case capacity in each of these regions is estimated to install recirculating wet cooling towers under this option (see Table B8-1).

f. Market fuel costs

Table B8-9 presents the base case fuel costs, as well as fuel costs under the two alternative options, and the percent change in fuel costs between the base case and the options by NERC region.

Table B8-9: National Fuel Costs/MWh Generation in 2013 (in millions, $2001; by NERC Region)[a]

NERC Region	Base Case Fuel Costs	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Fuel Costs	% Change	Fuel Costs	% Change
ECAR	9.46	9.45	-0.1%	9.76	3.2%
ERCOT	15.24	15.24	0.0%	15.33	0.6%
FRCC	16.26	16.35	0.6%	16.42	1.0%
MAAC	11.01	11.11	0.8%	11.26	2.2%
MAIN	10.17	10.20	0.3%	10.47	2.9%
MAPP	9.15	9.14	0.0%	9.26	1.2%
NPCC	16.56	16.67	0.6%	16.76	1.2%
SERC	10.87	10.88	0.1%	11.03	1.5%
SPP	11.77	11.77	0.0%	11.85	0.7%
WSCC	10.14	10.39	2.5%	10.40	2.6%

[a] Percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: Seven of the ten NERC regions experience a change in fuel cost as a result of this option. The largest increase in fuel costs per MWh of generation occurs in WSCC at 2.5 percent. This increase occurs in part due to the nuclear facility closure. Since regional demand for generation does not change, new and repowered combined cycle and combustion turbine capacity comes on-line. This capacity, and its subsequent generation, increases the demand on the fuel supply, increasing the cost of fuel in the region. No other region experiences an increase in fuel costs of more than 0.8 percent. One region, ECAR, experiences a decrease of 0.1 percent.

All cooling towers option: The cost of fuel increases in each of the ten NERC regions under this option. These increases exceed 1.0 percent in all but two regions, ERCOT and SPP. ECAR and MAIN experience the greatest impact in this measure as fuel costs per MWh of generation increase by 3.2 percent and 2.9 percent, respectively.

g. Market electricity prices

Table B8-10 presents base case energy prices as well as energy prices and the percent change under each of the two alternative options, by NERC region. Table B8-11 presents the same information for capacity prices in each region.

Table B8-10: Energy Prices in 2013 ($2001 per KWh; by NERC Region)[a]

NERC Region	Base Case Energy Prices	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Energy Prices	% Change	Energy Prices	% Change
ECAR	23.12	23.13	0.0%	23.54	1.8%
ERCOT	26.88	26.89	0.0%	27.00	0.4%
FRCC	29.21	29.36	0.5%	29.52	1.1%
MAAC	26.98	27.15	0.6%	27.14	0.6%
MAIN	22.95	22.97	0.1%	23.16	0.9%
MAPP	21.68	21.69	0.0%	21.70	0.1%
NPCC	30.84	30.76	-0.3%	30.87	0.1%
SERC	24.64	24.65	0.0%	24.74	0.4%
SPP	23.95	23.95	0.0%	24.02	0.3%
WSCC	26.25	26.21	-0.1%	26.27	0.1%

[a] Percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: The average annual price received for the sale of electricity remains unchanged in five NERC regions under this option. In three regions (FRCC, MAAC, and MAIN), it increases, and in two regions (NPCC and WSCC), it decreases. The two largest increases in energy prices occur in MAAC (0.6 percent) and FRCC (0.5 percent). All other things being equal, energy prices increase with an increase in the variable production costs of the last unit to be dispatched. Table B8-8 showed that MAAC and FRCC both experience an increase in variable production costs associated with a relatively high percentage of base case capacity that is estimated to install recirculating wet cooling towers under this option (see Table B8-1). Energy prices decrease in NPCC and WSCC despite increases in both production and fuel costs. This result is counter-intuitive but is due to the fact that each NERC region in the IPM consists of several subregions. For example, NPCC consists of five sub-regions. Energy prices increase in four of the five sub-regions but decrease in the largest sub-region. This decrease outweighs the increases in the other sub-regions while the other four sub-regions are dominant in determining the average fuel and production costs in NPCC.

All cooling towers option: Energy prices increase in each of the ten NERC regions under this option, with the largest increases of 1.8 percent and 1.1 percent occurring in ECAR and FRCC, respectively. As indicated above, an increase in energy prices results from an increase in variable production costs. Table B8-8 showed that variable production costs increase for all 10 NERC regions under this option.

Table B8-11: Capacity Prices in 2013 ($2001 per KW per year; by NERC Region)[a]

NERC Region	Base Case Capacity Prices	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Capacity Prices	% Change	Capacity Prices	% Change
ECAR	56.62	56.53	-0.2%	57.02	0.7%
ERCOT	29.93	29.86	-0.2%	29.91	-0.1%
FRCC	38.52	37.77	-2.0%	37.06	-3.8%
MAAC	50.40	49.63	-1.5%	50.28	-0.2%
MAIN	55.63	55.57	-0.1%	55.80	0.3%
MAPP	52.64	52.59	-0.1%	54.19	3.0%
NPCC	32.57	36.86	13.2%	37.98	16.6%
SERC	48.98	48.96	0.0%	48.96	0.0%
SPP	44.83	44.81	0.0%	44.52	-0.7%
WSCC	26.81	27.34	2.0%	27.08	1.0%

[a] Percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: The majority of NERC regions experience a reduction in capacity prices. Only two regions, NPCC and WSCC, experience an increase. The largest increase in capacity price occurs in NPCC (13.2 percent). This increase is likely the result of the decrease in total available capacity in this region, in part due to the closure of existing capacity (see Table B8-2) while generation, or demand for electricity, remains stable. This combination of factors suggests that a higher percentage of existing capacity is required to meet demand in this region. As such, facilities that are not dispatched under the base case, and thus are available for reserves, are dispatched under this option. As a result, less capacity would be available for reserves and capacity price increases.

All cooling towers option: All but one NERC region experiences a change in capacity prices under this option. As was the case under the waterbody/capacity-based option, the largest increase in capacity prices occurs in NPCC (16.6 percent), and the largest decrease in capacity prices occurs in FRCC (3.8 percent). No other region experiences increases or decreases of this magnitude in capacity prices under this option.

B8-3 Analysis of Phase II Facilities

This section presents the results of the IPM analysis for the Phase II facilities that are modeled by the IPM. Fifteen of the 540 Phase II facilities are identified as baseline closures, and are therefore not represented in these results. (In some cases, a facility that is a closure in the base case is operational in the post-compliance run. Such facilities are not represented in the base case but would be represented in the post-compliance scenario.) Except where noted, the results in this section therefore reflect the 525 weighted, non-closure, Phase II facilities modeled by the IPM.

EPA used the IPM results to analyze impacts on Phase II facilities at two levels: (1) potential changes in the economic and operational characteristics of the group of Phase II facilities and (2) potential changes to individual facilities within the group of Phase II facilities. It should be noted that the results of both analyses only include the steam electric components of the Phase II facilities and thus do not provide complete measures for in-scope facilities that also operate non-steam electric generation, which is not subject to this rule.

B8-3.1 Group of Phase II Facilities

This section presents the analysis of the potential impacts of each of the two alternative options on the group of Phase II facilities. Section B3-3.2 of *Chapter B3: Electricity Market Model Analysis* presents a detailed discussion of the seven impact measures developed using IPM output from model run year 2013 and used to assess potential changes in the economic and operational characteristics of this group of facilities.

a. Phase II plant closures

Table B8-12 presents the number of operational Phase II facilities under the base case and, for the two alternative options, the number and percent of total Phase II facilities that would close by NERC region. Table B8-13 presents the base case capacity of Phase II facilities and the capacity of closures under each option by NERC region. The table also presents capacity of closures expressed as a percentage of total base case Phase II capacity.

Table B8-12: Number of Facilities with Closure Units in 2013 (by NERC Region)[a]

NERC Region	Base Case Facilities	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Closures	% Change	Closures	% Change
ECAR	99	0	0.0%	1	1.0%
ERCOT	51	0	0.0%	1	2.0%
FRCC	30	0	0.0%	0	0.0%
MAAC	41	0	0.0%	0	0.0%
MAIN	47	0	0.0%	0	0.0%
MAPP	42	0	0.0%	0	0.0%
NPCC	54	-1	-1.9%	0	0.0%
SERC	95	0	0.0%	0	0.0%
SPP	32	0	0.0%	1	3.1%
WSCC	33	2	6.0%	2	6.0%
Total	**525**	**1**	**0.2%**	**5**	**1.0%**

[a] Percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Table B8-13: Capacity of Closure Units by 2013 (MW; by NERC Region)[a]

NERC Region	Base Case Phase II Capacity	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Closure Capacity	% of Total	Closure Capacity	% of Total
ECAR	78,680	0	0.0%	2,060	2.6%
ERCOT	42,330	0	0.0%	420	1.0%
FRCC	24,460	0	0.0%	0	0.0%
MAAC	30,310	0	0.0%	0	0.0%
MAIN	33,650	0	0.0%	490	1.5%
MAPP	14,900	0	0.0%	0	0.0%
NPCC	36,360	650	1.8%	720	2.0%
SERC	100,780	0	0.0%	0	0.0%
SPP	19,990	0	0.0%	20	0.1%
WSCC	30,110	2,170	7.2%	2,170	7.2%
Total	**411,570**	**2,820**	**0.7%**	**5,880**	**1.4%**

[a] Capacities have been rounded to the nearest 10, and percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: Table B8-12 shows that two regions, NPCC and WSCC, experience a change in closures of Phase II facilities as a result of this option. One fewer facility would close in NPCC in comparison to the base case: two facilities that would have retired in the baseline remain operational under the analyzed option while another, with higher post-compliance production costs, would close. As the total capacity of the single facility expected to close under this option exceeds that of the two avoided closures, NPCC experiences a net reduction of 650 MW, or 1.8 percent of baseline Phase II capacity . The largest reduction in baseline Phase II capacity occurs in WSCC where one large nuclear and one small oil/gas facility, accounting for 7.2 percent of total base case Phase II capacity, closes under this option.

All cooling towers option: A total of five Phase II facilities from four NERC regions (ECAR, ERCOT, SPP and WSCC) accounting for 5,880 MW, or 1.4 percent of base case Phase II capacity, closes under this option. The largest closures would occur in WSCC and ECAR where 7.2 percent (2,170 MW) and 2.6 percent (2,060 MW) respectively of base case Phase II capacity would close.

b. Phase II non-dispatch facilities

Table B8-14 presents the total base case capacity, as well as total non-dispatched capacity under the base case and both alternative options by NERC region. For each of these three scenarios total non-dispatched capacity is expressed as a percentage of total base case capacity in the region. The difference between total non-dispatched capacity as a percentage of total base case capacity for each of the regulatory options and total base case non-dispatched capacity as a percentage of total base case capacity is calculated and presented in bold.

Table B8-14: Capacity of Non-Dispatch Facilities in 2013 (MW; by NERC Region)[a]

NERC Region	Total Base Case Capacity	Base Case Capacity of Non-Dispatch Facilities	Non-Dispatch Capacity as a % of Total	Waterbody/Capacity-Based Option			All Cooling Towers Option		
				Non-Dispatch Capacity	Non-Dispatch Capacity as a % of Total	Difference	Non-Dispatch Capacity	Non-Dispatch Capacity as a % of Total	Difference
ECAR	78,680	190	0.2%	190	0.2%	**0.0%**	190	0.2%	**0.0%**
ERCOT	42,330	5,830	13.8%	5,790	13.7%	**-0.1%**	5,740	13.6%	**-0.2%**
FRCC	24,460	7,800	31.9%	6,540	26.7%	**-5.2%**	7,700	31.5%	**-0.4%**
MAAC	30,310	2,070	6.8%	2,070	6.8%	**0.0%**	2,070	6.8%	**0.0%**
MAIN	33,650	2,760	8.2%	2,760	8.2%	**0.0%**	2,760	8.2%	**0.0%**
MAPP	14,900	330	2.2%	330	2.2%	**0.0%**	320	2.1%	**-0.1%**
NPCC	36,360	7,690	21.2%	7,570	20.8%	**-0.3%**	6,980	19.2%	**-2.0%**
SERC	100,780	5,060	5.0%	6,100	6.1%	**1.0%**	6,750	6.7%	**1.7%**
SPP	19,990	2,130	10.7%	2,130	10.7%	**0.0%**	2,080	10.4%	**-0.3%**
WSCC	30,110	4,290	14.2%	5,390	17.9%	**3.7%**	5,740	19.1%	**4.8%**
Total	**411,570**	**38,150**	**9.3%**	**38,870**	**9.4%**	**0.2%**	**40,330**	**9.8%**	**0.5%**

[a] Capacities have been rounded to the nearest 10, and percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: In total, non-dispatched capacity as a percentage of base case capacity increases by 0.2 percent under this option. By far the largest increase in this metric occurs in WSCC (3.7 percent). This result suggests that Phase II facilities in this region become less competitive and are dispatched less frequently as a result of this option. The increase in the variable production costs of Phase II facilities shown in Table B8-18 supports this finding. The largest decrease in non-dispatched capacity as a percentage of base case capacity occurs in FRCC (5.2 percent). This reduction implies that a *higher* percentage of Phase II capacity would be dispatched under this option relative to the base case, despite the increased production cost of these facilities (see Table B8-18). This difference is due to one large oil/gas facility that is not dispatched under the baseline, but is dispatched under the option.

All cooling towers option: Overall, non-dispatched capacity as a percentage of base case capacity increases by 0.5 percent under this option. As was the case under the waterbody/capacity-based option, the largest increase occurs in WSCC (4.8 percent) due most likely to the increased variable production costs of Phase II facilities in this region (see Table B8-18). The largest decrease in non-dispatched capacity as a percentage of base case capacity occurs in NPCC (2.0 percent).

c. Phase II capacity

Table B8-15 presents the total Phase II capacity under the base case and each of the alternative regulatory options by NERC region. Total Phase II capacity associated with each option is expressed as a percentage of total base case Phase II capacity.

Table B8-15: Capacity in 2013 (MW; by NERC Region)[a]

NERC Region	Base Case Capacity	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Capacity	% Change	Capacity	% Change
ECAR	78,680	78,680	0.0%	75,690	-3.8%
ERCOT	42,330	42,270	-0.1%	41,400	-2.2%
FRCC	24,460	24,330	-0.5%	24,200	-1.1%
MAAC	30,310	30,180	-0.4%	30,030	-0.9%
MAIN	33,650	33,650	0.0%	32,790	-2.6%
MAPP	14,900	14,900	0.0%	14,700	-1.3%
NPCC	36,360	35,220	-3.1%	34,500	-5.1%
SERC	100,780	100,680	-0.1%	99,540	-1.2%
SPP	19,990	19,990	0.0%	19,840	-0.8%
WSCC	30,110	27,540	-8.5%	26,280	-12.7%
Total	**411,570**	**407,440**	**-1.0%**	**398,970**	**-3.1%**

[a] Capacities have been rounded to the nearest 10, and percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: In aggregate, this option results in a reduction in Phase II capacity of 4,130 MW, or 1.0 percent. A majority of the decrease (2,820 MW) is due to closures. The residual 1,310 MW is due to energy penalties. Capacity decreases in six NERC regions, while remaining unchanged the other four. The two largest reductions in this metric occur in WSCC and NPCC, which experience reductions of 8.5 percent and 3.1 percent of base case capacity, respectively. In both regions, the majority of this reduction in available capacity is associated with the economic closure of existing Phase II facilities (see Table B8-13).

All cooling towers option: Overall, there is a reduction in available capacity of approximately 12,600 MW, or 3.1 percent of total base case capacity. Of the 12,600 MW, 5,880 (47 percent) are due to closures. The residual 6,720 MW is due to energy penalties. The three largest reductions occur in WSCC (12.7 percent), NPCC (5.1 percent), and ECAR (3.8 percent). As was the case under the waterbody/capacity-based option, the majority of this reduction in available capacity is associated with the economic closure of existing Phase II facilities (see Table B8-13).

d. Phase II generation

Table B8-16 presents the base case generation, and total generation under each of the two alternative options and the percent change in generation between the base case and each option by NERC region.

Table B8-16: Generation in 2013 (Million MWh; by NERC Region)[a]

NERC Region	Base Case Generation	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Generation	% Change	Generation	% Change
ECAR	521	521	0.0%	510	-2.1%
ERCOT	153	153	0.0%	147	-4.1%
FRCC	80	78	-3.3%	77	-4.1%
MAAC	171	169	-1.3%	167	-2.3%
MAIN	216	216	0.0%	211	-2.5%
MAPP	105	105	0.0%	104	-1.3%
NPCC	158	149	-5.5%	142	-10.1%
SERC	630	630	-0.1%	621	-1.5%
SPP	110	110	0.0%	109	-1.2%
WSCC	145	118	-18.8%	100	-30.9%
Total	**2,290**	**2,249**	**-1.8%**	**2,188**	**-4.5%**

[a] Percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: In aggregate, generation decreases by 1.8 percent as a result of this option. The two largest reductions are experienced in WSCC (18.8 percent) and NPCC (5.5 percent). These decreases in generation are most likely attributable to the reductions in capacity resulting from closures and the energy penalty, and the increased variable production costs of non-closure Phase II facilities that occur in these two regions under this option (see Tables B8-15 and B8-18).

All cooling towers option: Overall, this option results in a 4.5 percent decrease in generation. While every region experiences a reduction in this metric, the two largest reductions occur in WSCC (30.9 percent) and NPCC (10.1 percent). As was the case under the waterbody/capacity-based option, these reductions are likely due to reductions in available capacity and increased production costs of non-closure Phase II facilities (see Tables B8-15 and B8-18).

e. Phase II revenues

Table B8-17 presents total Phase II revenues under the base case and each of the two alternative regulatory options by NERC region. Revenues associated with each option are also expressed as a percentage of total base case revenues.

Table B8-17: Revenues in 2013 (in millions, $2001; by NERC Region)[a]

NERC Region	Base Case Revenues	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Revenues	% Change	Revenues	% Change
ECAR	16,370	16,370	0.0%	16,200	-1.0%
ERCOT	5,440	5,430	-0.2%	5,260	-3.3%
FRCC	3,240	3,170	-2.2%	3,140	-3.1%
MAAC	6,070	6,020	-0.8%	5,990	-1.3%
MAIN	6,730	6,730	0.0%	6,610	-1.8%
MAPP	3,020	3,020	0.0%	3,010	-0.3%
NPCC	5,980	5,790	-3.2%	5,600	-6.4%
SERC	20,190	20,180	0.0%	19,990	-1.0%
SPP	3,450	3,450	0.0%	3,420	-0.9%
WSCC	4,880	4,040	-17.2%	3,510	-28.1%
Total	**75,370**	**74,200**	**-1.6%**	**72,730**	**-3.5%**

[a] Revenues have been rounded to the nearest 10, and percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: In total, there is a reduction in revenues of 1.6 percent associated with this option. Revenues decrease in five NERC regions and remain unchanged in the others. The two largest reductions in revenues occur in WSCC (17.2 percent) and NPCC (3.2 percent). The reduction in generation and price shown in Tables B8-16 and B8-10, respectively, are likely the principal cause for the reductions in revenues in these regions.

All cooling towers option: Every NERC region experiences a reduction in revenues as a result of this option. In aggregate, these reductions account for 3.5 percent of base case revenues. As was the case under the waterbody/capacity option, the two largest reductions in revenues occur in WSCC (28.1 percent) and NPCC (6.4 percent), the two regions with the largest reductions in generation under this option (see Table B8-16). The reductions in generation and price shown in Tables B8-16 and B8-10, respectively, are the likely cause for the reductions in revenues in these regions.

f. Phase II variable production costs

Table B8-18 presents the base case variable production costs per MWh of generation, as well as variable production costs under the each of the two alternative options and the percent change in variable production costs between the base case and each of the two alternative options by NERC region.

Table B8-18: Variable Production Costs/MWh Generation in 2013 (in millions, $2001; by NERC Region)[a]

NERC Region	Base Case Production Costs	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Production Costs	% Change	Production Costs	% Change
ECAR	11.59	11.58	-0.1%	11.75	1.4%
ERCOT	15.67	15.68	0.0%	15.60	-0.5%
FRCC	15.21	15.32	0.7%	15.32	0.8%
MAAC	11.43	11.43	0.0%	11.32	-1.0%
MAIN	11.30	11.30	0.0%	11.46	1.4%
MAPP	11.04	11.04	0.0%	11.19	1.3%
NPCC	18.43	18.39	-0.2%	18.38	-0.3%
SERC	11.16	11.16	0.0%	11.27	1.0%
SPP	12.13	12.13	0.0%	12.15	0.1%
WSCC	16.83	17.48	3.9%	17.26	2.6%

[a] Percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: Four NERC regions experience a change in variable production costs per MWh of generation under this option. The largest increase occurs in WSCC (3.9 percent). This increase is most likely attributable to the increase in production costs of non-closure Phase II facilities, and the economic closure of Phase II capacity. The majority of the 2,170 MW of closed capacity in the WSCC region listed in Table B8-13, is relatively low cost nuclear capacity. The elimination of low cost nuclear capacity from the group of Phase II facilities in this region increases the average variable production cost for the group in this region. In NPCC, the economic closure of relatively high cost oil and gas fired capacity is most likely responsible for the 0.2 percent reduction in variable production costs of Phase II facilities.

All cooling towers option: Seven NERC regions experience an increase in variable production costs under this option while the remaining three see a decrease in this metric. As was the case under the waterbody/capacity-based option, data presented in Table B8-13 suggest the economic closure of low cost nuclear capacity in WSCC is most likely responsible for the largest increase in variable production costs per MWh (2.6 percent). The largest decrease in variable production costs would occur in ERCOT, at 0.5 percent.

g. Phase II fuel costs

Table B8-19 presents the base case fuel costs as well as fuel costs under the two alternative options and the percent change in fuel costs between the base case and the two options by NERC region.

Table B8-19: Fuel Costs/MWh Generation in 2013 (in millions, $2001; by NERC Region)[a]

NERC Region	Base Case Fuel Costs	Waterbody/Capacity-Based Option		All Cooling Towers Option	
		Fuel Costs	% Change	Fuel Costs	% Change
ECAR	9.13	9.13	-0.1%	9.29	1.7%
ERCOT	12.89	12.89	0.1%	12.82	-0.5%
FRCC	12.80	12.92	0.9%	12.96	1.2%
MAAC	9.28	9.27	-0.1%	9.18	-1.1%
MAIN	9.06	9.06	0.0%	9.22	1.8%
MAPP	8.99	8.99	0.0%	9.13	1.5%
NPCC	16.73	16.67	-0.3%	16.64	-0.6%
SERC	9.01	9.01	0.0%	9.12	1.3%
SPP	9.90	9.90	0.0%	9.91	0.1%
WSCC	14.72	15.35	4.3%	14.97	1.7%

[a] Percent changes have been rounded to the nearest 10th.

Source: IPM analysis: model runs for Section 316(b) Base Case, Waterbody/Capacity-Based Option, and All Cooling Towers Option.

Waterbody/capacity-based option: Six of the ten NERC regions experience a change in fuel cost per MWh of generation as a result of this option. This increase occurs in part due to the nuclear facility closure. Since total regional demand for generation does not change (Table B8-6), new and repowered combined cycle and combustion turbine capacity comes on-line (Tables B8-4 and B8-5). This capacity, and its subsequent generation, increases the demand on the fuel supply, increasing the cost of fuel in the region. The largest increase in fuel costs occurs in WSCC (4.3 percent) while the largest decrease occurs in NPCC (0.3 percent).

All cooling towers option: Fuel cost per MWh of generation changes in each of the ten NERC regions under this option. The largest increases in fuel cost per MWh of generation occur in MAIN (1.8 percent), ECAR (1.7 percent), and WSCC (1.7 percent). The largest decrease in fuel costs occurs in MAAC, (at 1.1 percent).

B8-3.2 Individual Phase II Facilities

In addition to effects of the two alternative options in the group of Phase II facilities, there may be shifts in economic performance among individual facilities subject to section 316(b) regulation. To assess potential distributional effects, EPA analyzed facility-specific changes in net generation, production costs, capacity utilization, revenue, and operating income. For each measure, EPA determined the number of Phase II facilities that experience an increase or a reduction within three ranges: 0 to 1 percent, 1 to 3 percent, and 3 percent or more. Excluded from this analysis were facilities experiencing significant structural changes as a result of a policy option, including partial or full closures, avoided closures, or repowering.

Tables B8-20 and B8-21 present the total number of Phase II facilities with different degrees of change in each of these measures under the waterbody/capacity-based and all cooling towers options.

Table B8-20: Operational Changes at Phase II Facilities from the Waterbody/Capacity-Based Option (2013)[a, b]

Economic Measures	Reduction			Increase			No Change
	0-1%	1-3%	> 3%	0-1%	1-3%	> 3%	
Change in Net Generation	7	17	21	4	4	9	444
Change in Variable Production Costs	6	5	1	13	16	3	380
Change in Capacity Utilization	10	7	12	7	3	5	462
Change in Total Revenue	57	43	17	48	15	20	306
Change in Operating Income	75	42	10	46	15	22	296

[a] For all measures percentages used to assign facilities to impact categories have been rounded to the nearest 10th of a percent.

[b] Of the 540 Phase II facilities, 34 would experience a significant structural change as a result of the rule, and are therefore excluded from this analysis. Of the remaining 506 facilities, 82 facilities had zero generation in either the base case or post compliance scenario. It was therefore not possible to calculate the change in variable production costs for these facilities. As a result, the number of facilities adds up to 424 instead of 506 for this measure.

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-20 indicates that the majority of Phase II facilities do not experience changes in generation, production costs, or capacity utilization due to compliance with the waterbody/capacity-based option. Of those facilities with changes in post-compliance generation and capacity utilization, most experience decreases in these measures. In addition, while approximately 40 percent of Phase II facilities experience an increase or decrease in revenues and/or operating income, the magnitude of such changes are small.

Table B8-21: Operational Changes at Phase II Facilities from the All Cooling Towers Option (2013)[a, b]

Economic Measures	Reduction			Increase			No Change
	0-1%	1-3%	> 3%	0-1%	1-3%	> 3%	
Change in Net Generation	18	251	53	3	4	22	151
Change in Variable Production Costs	16	12	4	64	257	17	51
Change in Capacity Utilization	15	25	25	8	12	15	402
Change in Total Revenue	154	121	55	88	39	35	10
Change in Operating Income	118	160	50	83	47	29	15

[a] For all measures percentages used to assign facilities to impact categories have been rounded to the nearest 10th of a percent.

[B] Of the 540 Phase II facilities, 38 would experience a significant structural change as a result of the rule, and are therefore excluded from this analysis. Of the remaining 502 facilities, 81 facilities had zero generation in either the base case or post-compliance scenario. It was therefore not possible to calculate the change in variable production costs for these facilities. As a result, the number of facilities adds up to 421 instead of 502 for this measure.

Source: IPM analysis: model runs for Section 316(b) base case and all cooling towers option.

Table B8-21 indicates that under the all cooling towers option, more facilities would experience changes in their operations and economic performance than under the waterbody/capacity-based option. For example, 322 out of 502 facilities, or 64

percent, experience a reduction in generation.[6] In addition, 328 facilities experience a reduction in operating income while 338 facilities see their production cost per MWh increase. However, some facilities benefit from regulation under this option: 162 facilities experience an increase in revenues and 159 experience an increase in operating income.

B8-4 Uncertainties and Limitations

EPA has identified uncertainties and limitations associated with the electricity market model analysis of the waterbody/capacity-based option and the all cooling towers option. These uncertainties and limitations are discussed below.

Capacity Utilization Assumption Used in IPM Analysis: EPA estimated compliance responses for in-scope facilities and developed compliance costs using capacity utilization rates from EIA data sources (average 1995-1999 generation from Form EIA-906; average 1995-1999 capacity from Forms EIA-860A and 860B). However, this capacity utilization rate does not always match the rate projected by the IPM for run year 2008. A discrepancy between the rates from the two data sources may lead to an overestimation or underestimation of economic impacts and/or energy effects in the market model analysis using the IPM.

Facilities with a capacity utilization rate of less than 15 percent would be subject to less stringent compliance requirements under the proposed rule and the two analyzed alternative regulatory options, partially because stringent compliance requirements, and high compliance costs, are not required if the facility is used on an intermittent basis only. Economically, a low utilization rate means lower revenues as the facility generates and sells less electricity (this fact is somewhat mitigated by the presence of capacity revenues in the IPM). Using a capacity utilization rate from EIA sources could introduce two types of errors in the economic impact analysis based on the IPM. These errors arise from the following two scenarios: (1) A facility was costed with less stringent compliance requirements because its EIA capacity utilization rate is less than 15 percent. However, its IPM rate is greater than 15 percent. Such a facility is undercosted relative to its economic condition modeled by the IPM. (2) A facility was costed with the full compliance requirements because its EIA capacity utilization rate is greater than 15 percent. However, its IPM rate is less than 15 percent. Such a facility is overcosted relative to its economic condition modeled by the IPM.

To assess the potential uncertainty associated with using a capacity utilization rate that does not always match the assumption of the IPM, EPA compared the rates between the EIA data sources and the IPM. This comparison showed that 56 out of the 540 in-scope facilities modeled by the IPM would fall under the 15 percent capacity utilization threshold based on the EIA data. Of these 56 facilities, 21 exceed the 15 percent threshold based on IPM data. These 21 facilities, or 3.9 percent of all facilities, have potentially been undercosted. Conversely, 112 facilities would fall under the 15 percent capacity utilization threshold based on the IPM data. Of these 112 facilities, 77 exceed the 15 percent threshold based on EIA data. These 77 facilities, or 14.3 percent of all facilities, have potentially been overcosted. Table B8-22 summarizes the differences between the EIA and IPM capacity utilization rates.

Table B8-22: Comparison of EIA and IPM Capacity Utilization Rates

Capacity Utilization < 15% in both EIA and IPM	407
Capacity Utilization < 15% in IPM, but > 15 % in EIA	77
Capacity Utilization < 15% in EIA, but > 15 % in IPM	21
Capacity Utilization > 15% in both EIA and IPM	35
Total	540

Source: IPM analysis: model run for Section 316(b) Base Case; U.S. DOE, 1999a; U.S. DOE, 1999b.

The largest cost differential is associated with facilities that would or would not be costed with a recirculating cooling tower based on their capacity utilization. EPA therefore compared the number of facilities that would be costed with a cooling

[6] As explained earlier, facilities with significant status changes (including baseline closures, avoided closures, and facilities that repower) are excluded from this comparison.

tower under the waterbody/capacity-based option, using the two respective capacity utilization rates. With the EIA rate, EPA determined that of 60 facilities meeting the criteria that would require a cooling tower, 52 have a capacity utilization rate of greater than 15 percent. For the analysis presented in this chapter, these 52 facilities were costed with a cooling tower. However, with the IPM capacity utilization rate, 16 of these 52 facilities would not have been costed with a cooling tower. Conversely, of the eight facilities that were not costed with a cooling tower based on the 15 percent threshold using the EIA rate, two facilities would have been costed with a cooling tower, had the IPM rate been used. The differential between the two utilization rates is therefore 14 cooling towers (16 minus 2).

Based on these analyses, EPA concludes that a capacity utilization rate using EIA data would likely overstate the total cost of the proposed rule and the alternative regulatory options, and therefore lead to a conservative estimate of economic impacts.

Data Input Errors: Due to a costing error, the compliance costs of one facility located in MAAC were understated in the IPM analysis of the waterbody/capacity-based option. The facility should have been costed with a fish handling and return system and annualized compliance cost of approximately $1.2 million. The IPM input represented no compliance technology and annualized compliance costs of less than $100,000. As a result of the understatement of compliance costs for this facility, the IPM analysis may have underestimated production costs in this region, thereby potentially increasing the dispatch of this facility.

Modeling Issues: EPA identified three modeling issues that could potentially impact the magnitude of the results of the IPM analysis. These issues are associated with: (1) repowering, (2) downtime associated with cooling tower connection, and (3) application of the energy penalty. ***Repowering:*** For the section 316(b) analysis, EPA is not using the IPM function that allows the model to pick among a set of compliance responses. As a result, there is no iterative process that would adjust the compliance response, and as a result the cost of compliance, if a facility chooses to repower. In the IPM, some oil/gas facilities repower to combined-cycle prime movers. This would often lead to a reduction in intake flow and potentially to less stringent compliance requirements or to lower costs (for costs that are a function of intake flow). Not allowing the model to adjust the compliance response or cost would lead to a conservative estimate of compliance costs and potential economic impacts from the proposed rule and the alternative regulatory options analyzed with the IPM. ***Downtime associated with cooling tower connection:*** EPA assumes that it would take one month of generator down-time to install and connect a recirculating cooling tower. As a result of the current specification of seasons in the IPM, it is not possible to model the downtime as a 100 percent outage during one month. Instead, the downtime is spread over the entire winter season of seven months and is represented as if a 1/7th of the facility were down for a period of seven months. It is unclear how this current modeling constraint would impact the results of the model. It is possible that short term impacts that would lead to temporary price increases would be understated, leading to an overall lower average price over the model run year. ***Application of the energy penalty:*** Due to a programming error in the model, which could not be resolved in time for the proposed rule, the energy penalty for some facilities was incorrectly applied. This problem affected one out of 52 facilities for the waterbody/capacity-based option and nine out of 416 facilities for the all cooling towers option. As a result of this omission, regional energy effects and impacts on the facilities in question may have been understated.

REFERENCES

U.S. Department of Energy (U.S. DOE). 1999a. *Form EIA-860A (1999). Annual Electric Generator Report – Utility*.

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U.S. Environmental Protection Agency (U.S. EPA). 2002. *Documentation of EPA Modeling Applications (V.2.1) Using the Integrated Planning Model*. EPA 430/R-02-004. March 2002.

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Appendix to Chapter B8

EPA conducted model runs based on two different electricity demand assumptions: (1) a case using EPA's electricity demand assumptions and (2) a case using Annual Energy Outlook (AEO) electricity demand assumptions.[7] The analyses presented in this appendix are based on using Annual Energy Outlook (AEO) electricity demand assumptions; the main body of Chapter B8 presented the results using EPA's assumptions. Under the EPA assumption, the demand for electricity is based on the AEO 2001 forecast adjusted to account for demand reductions resulting from implementation of the Climate Change Action Plan (CCAP). The AEO electricity demand assumption, on the other hand, utilizes the AEO 2001 without adjustment. The remainder of this appendix presents the results of the waterbody/capacity-based option under the AEO electricity demand assumptions, and a comparison of the differences in results between the AEO based assumptions and the EPA based assumptions.

Appendix Contents

B8-A1 Market Analysis

This section presents the results of the IPM analysis for all facilities modeled by the IPM. The results in this section include facilities that are in-scope and facilities that are out-of-scope of section 316(b) regulation under the two demand assumptions presented above. Market level impacts associated with each of the alternative assumptions are assessed using seven impact measures developed from IPM output for model run year 2013.[8] A detailed description of each of the impact measures presented below can be found in Section B3-3.1 of *Chapter B3: Electricity Market Model Analysis*.

[7] The Annual Energy Outlook reflects all current legislation and environmental regulations, such as the Clean Air Act Amendments of 1990.

[8] The IPM model simulates electricity market function for a period of 25 years. Model output is provided for five user-specified model run years. EPA selected three run years to provide output across the ten year compliance period for the rule. Analyses of regulatory options are based on output for model run years that reflect a scenario in which all facilities are operating in their post-compliance condition. Options requiring the installation of cooling towers are analyzed using output from model run year 2013.

Table B8-A-1: National Capacity of Closure Units in 2013 (MW; by NERC Region)

NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	133,020	0	0.0%	0.0%	**0.0%**
ERCOT	86,610	0	0.0%	0.0%	**0.0%**
FRCC	57,080	0	0.0%	0.0%	**0.0%**
MAAC	70,530	1,110	1.6%	0.0%	**1.6%**
MAIN	66,420	0	0.0%	0.0%	**0.0%**
MAPP	39,700	0	0.0%	0.0%	**0.0%**
NPCC	79,360	460	0.6%	1.1%	**-0.5%**
SERC	220,570	0	0.0%	0.0%	**0.0%**
SPP	55,710	0	0.0%	0.0%	**0.0%**
WSCC	186,000	0	0.0%	1.3%	**-1.3%**
Total	**995,000**	**1,570**	**0.2%**	**0.3%**	**-0.1%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-2: National Domestic Capacity in 2013 (MW; by NERC Region)

NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	133,020	133,020	0.0%	0.1%	**-0.1%**
ERCOT	86,610	86,550	-0.1%	-0.1%	**0.0%**
FRCC	57,080	56,960	-0.2%	-0.3%	**0.1%**
MAAC	70,530	70,420	-0.2%	-0.2%	**0.0%**
MAIN	66,420	66,240	-0.3%	0.0%	**-0.3%**
MAPP	39,700	39,700	0.0%	-0.1%	**0.1%**
NPCC	79,360	79,070	-0.4%	-0.3%	**-0.1%**
SERC	220,570	220,710	0.1%	-0.1%	**0.2%**
SPP	55,710	55,710	0.0%	0.0%	**0.0%**
WSCC	186,000	185,860	-0.1%	-0.1%	**0.0%**
Total	**995,000**	**994,240**	**-0.1%**	**-0.1%**	**0.0%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-3: National Domestic Capacity Additions in 2013 (MW; by NERC Region)

NERC Region	AEO Electricity Demand Assumptions						% Change from EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case Total Capacity	Base Case Additions	% Change	Post-Compliance Additions	% Change	Difference		
ECAR	133,020	22,990	17.3%	22,990	17.3%	**0.0%**	**0.1%**	**-0.1%**
ERCOT	86,610	11,320	13.1%	11,310	13.1%	**0.0%**	**0.0%**	**0.0%**
FRCC	57,080	17,840	31.3%	17,860	31.3%	**0.0%**	**0.0%**	**0.0%**
MAAC	70,530	11,450	16.2%	12,580	17.8%	**1.6%**	**0.1%**	**1.5%**
MAIN	66,420	15,300	23.0%	15,120	22.8%	**-0.3%**	**0.0%**	**-0.3%**
MAPP	39,700	7,020	17.7%	7,020	17.7%	**0.0%**	**-0.1%**	**0.1%**
NPCC	79,360	11,490	14.5%	11,930	15.0%	**0.6%**	**1.4%**	**-0.8%**
SERC	220,570	56,020	25.4%	56,260	25.5%	**0.1%**	**-0.1%**	**0.2%**
SPP	55,710	6,750	12.1%	6,750	12.1%	**0.0%**	**0.0%**	**0.0%**
WSCC	186,000	25,560	13.7%	25,460	13.7%	**-0.1%**	**0.7%**	**-0.8%**
Total	**995,000**	**185,740**	**18.7%**	**187,280**	**18.8%**	**0.2%**	**0.2%**	**0.0%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-4: National Repowering Capacity in 2013 (MW; by NERC Region)

NERC Region	AEO Electricity Demand Assumptions						% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case Total Capacity	Base Case Repowered Capacity	Repowering as a % of Total Base Case Capacity	Post-Compliance Repowering	Repowering as a % of Total Base Case Capacity	Difference		
ECAR	133,020	0	0.0%	0	0.0%	**0.0%**	**0.0%**	**0.0%**
ERCOT	86,610	5,490	6.3%	5,510	0.4%	**-5.9%**	**0.0%**	**-5.9%**
FRCC	57,080	0	0.0%	0	0.0%	**0.0%**	**0.0%**	**0.0%**
MAAC	70,530	1,660	2.4%	1,640	-1.2%	**-3.6%**	**0.0%**	**-3.6%**
MAIN	66,420	0	0.0%	0	0.0%	**0.0%**	**0.0%**	**0.0%**
MAPP	39,700	0	0.0%	0	0.0%	**0.0%**	**0.0%**	**0.0%**
NPCC	79,360	7,960	10.0%	7,730	-2.9%	**-12.9%**	**-0.8%**	**-12.1%**
SERC	220,570	0	0.0%	0	0.0%	**0.0%**	**0.0%**	**0.0%**
SPP	55,710	0	0.0%	0	0.0%	**0.0%**	**0.0%**	**0.0%**
WSCC	186,000	7,550	4.1%	7,770	2.9%	**-1.2%**	**1.1%**	**-2.3%**
Total	**995,000**	**22,660**	**2.3%**	**22,650**	**0.0%**	**-2.3%**	**0.2%**	**-2.5%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-5: National Generation in 2013 (million MWh; by NERC Region)

NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	703	704	0.2%	0.0%	**0.2%**
ERCOT	389	389	0.0%	0.0%	**0.0%**
FRCC	218	218	0.0%	0.0%	**0.0%**
MAAC	311	310	-0.3%	-0.2%	**-0.1%**
MAIN	306	306	-0.1%	0.3%	**-0.4%**
MAPP	201	201	0.0%	0.0%	**0.0%**
NPCC	312	312	0.2%	-0.1%	**0.3%**
SERC	1,072	1,071	-0.1%	0.0%	**-0.1%**
SPP	244	244	0.0%	0.0%	**0.0%**
WSCC	849	849	0.0%	0.0%	**0.0%**
Total	**4,604**	**4,604**	**0.0%**	**0.0%**	**0.0%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-6: National Revenues in 2013 (in millions, $2001; by NERC Region)

NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	24,750	24,790	0.2%	0.0%	**0.2%**
ERCOT	13,480	13,470	-0.1%	0.0%	**-0.1%**
FRCC	8,890	8,910	0.2%	-0.3%	**0.5%**
MAAC	12,280	12,270	-0.1%	-0.2%	**0.1%**
MAIN	11,020	11,010	-0.1%	0.2%	**-0.3%**
MAPP	6,680	6,680	0.0%	0.0%	**0.0%**
NPCC	12,330	13,070	6.0%	2.4%	**3.6%**
SERC	38,060	38,050	0.0%	0.0%	**0.0%**
SPP	8,660	8,660	0.0%	0.0%	**0.0%**
WSCC	28,490	28,490	0.0%	0.2%	**-0.2%**
Total	**164,640**	**165,400**	**0.5%**	**0.2%**	**0.3%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-7: National Variable Production Costs/MWh Generation in 2013 ($2001; by NERC Region)

NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	12.51	12.53	0.1%	0.0%	**0.1%**
ERCOT	17.52	17.52	0.0%	0.0%	**0.0%**
FRCC	18.93	19.00	0.4%	0.4%	**0.0%**
MAAC	13.70	14.08	2.8%	0.7%	**2.1%**
MAIN	12.81	12.79	-0.1%	0.2%	**-0.3%**
MAPP	11.79	11.79	-0.1%	0.0%	**-0.1%**
NPCC	18.25	18.33	0.4%	0.5%	**-0.1%**
SERC	13.49	13.50	0.1%	0.1%	**0.0%**
SPP	14.19	14.19	0.0%	0.0%	**0.0%**
WSCC	12.19	12.20	0.1%	1.9%	**-1.8%**
Total	**13.85**	**13.89**	**0.3%**	**0.5%**	**-0.2%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-8: National Fuel Costs/MWh of Generation in 2013 (in millions, $2001; by NERC Region)

NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	10.11	10.13	0.2%	-0.1%	**0.3%**
ERCOT	15.59	15.59	0.0%	0.0%	**0.0%**
FRCC	17.04	17.12	0.4%	0.6%	**-0.2%**
MAAC	11.68	12.08	3.4%	0.8%	**2.6%**
MAIN	10.80	10.78	-0.2%	0.3%	**-0.5%**
MAPP	9.79	9.78	-0.1%	0.0%	**-0.1%**
NPCC	16.93	17.01	0.4%	0.6%	**-0.2%**
SERC	11.68	11.68	0.1%	0.1%	**0.0%**
SPP	12.40	12.40	0.0%	0.0%	**0.0%**
WSCC	10.72	10.72	0.1%	2.5%	**-2.4%**
Total	**12.01**	**12.05**	**0.3%**	**0.6%**	**-0.3%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-9: Energy Prices in 2013 ($2001 per KWh; by NERC Region)

NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	24.53	24.52	0.0%	0.0%	**0.0%**
ERCOT	26.77	26.81	0.1%	0.0%	**0.1%**
FRCC	29.66	29.58	-0.3%	0.5%	**-0.8%**
MAAC	27.94	27.98	0.1%	0.6%	**-0.5%**
MAIN	23.83	23.82	0.0%	0.1%	**-0.1%**
MAPP	22.37	22.37	0.0%	0.0%	**0.0%**
NPCC	30.68	30.67	0.0%	-0.3%	**0.3%**
SERC	25.46	25.46	0.0%	0.0%	**0.0%**
SPP	24.33	24.34	0.0%	0.0%	**0.0%**
WSCC	26.09	26.10	0.0%	-0.1%	**0.1%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-10: Capacity Prices in 2013 ($2001 per KW per year; by NERC Region)

NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	56.54	56.63	0.2%	-0.2%	**0.4%**
ERCOT	35.56	35.35	-0.6%	-0.2%	**-0.4%**
FRCC	42.33	43.13	1.9%	-2.0%	**3.9%**
MAAC	51.11	51.30	0.4%	-1.5%	**1.9%**
MAIN	56.15	56.16	0.0%	-0.1%	**0.1%**
MAPP	55.58	55.58	0.0%	-0.1%	**0.1%**
NPCC	37.80	47.65	26.0%	13.2%	**12.8%**
SERC	48.92	48.90	0.0%	0.0%	**0.0%**
SPP	48.94	48.94	0.0%	0.0%	**0.0%**
WSCC	37.04	37.06	0.1%	2.0%	**-1.9%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

B8-A2 Phase II Facility Analysis

EPA used the IPM results to analyze two potential facility-level impacts of the waterbody/capacity-based option: (1) potential changes in the economic and operational characteristics of the group of Phase II facilities and (2) potential changes to individual facilities within the group of Phase II facilities. It should be noted that the results of both analyses only include the steam electric components of the Phase II facilities and thus do not provide complete measures for in-scope facilities that also operate non-steam electric generation, which is not subject to this rule.

B8-A2.1 Group of Phase II Facilities

This section presents the analysis of the potential impacts of the waterbody/capacity-based option on the group of Phase II facilities. Section B3-3.2 of *Chapter B3: Electricity Market Model Analysis* presents a detailed discussion of the seven impact

measures developed using IPM output from model run year 2013 and used to assess potential changes in the economic and operational characteristics of this group of facilities.

Table B8-A-11: Number of Facilities with Closure Units in 2013 (by NERC Region)

NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	99	0	0.0%	0.0%	**0.0%**
ERCOT	51	0	0.0%	0.0%	**0.0%**
FRCC	30	0	0.0%	0.0%	**0.0%**
MAAC	41	1	2.4%	0.0%	**2.4%**
MAIN	47	0	0.0%	0.0%	**0.0%**
MAPP	42	0	0.0%	0.0%	**0.0%**
NPCC	57	(1)	-1.8%	-1.9%	**0.1%**
SERC	95	0	0.0%	0.0%	**0.0%**
SPP	32	0	0.0%	0.0%	**0.0%**
WSCC	34	0	0.0%	6.0%	**-6.0%**
Total	**528**	**0**	**0.0%**	**0.2%**	**-0.2%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-12: Capacity of Closure Units in 2013 (MW; by NERC Region)

NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	78,660	0	0.0%	0.0%	**0.0%**
ERCOT	43,460	0	0.0%	0.0%	**0.0%**
FRCC	24,440	0	0.0%	0.0%	**0.0%**
MAAC	31,410	1,110	3.5%	0.0%	**3.5%**
MAIN	34,140	0	0.0%	0.0%	**0.0%**
MAPP	14,890	0	0.0%	0.0%	**0.0%**
NPCC	37,290	930	2.5%	1.8%	**0.7%**
SERC	100,780	0	0.0%	0.0%	**0.0%**
SPP	19,990	0	0.0%	0.0%	**0.0%**
WSCC	30,950	0	0.0%	7.2%	**-7.2%**
Total	**416,010**	**2,040**	**0.5%**	**0.7%**	**-0.2%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-13: Capacity of Non-Dispatched Facilities in 2013 (MW; by NERC Region)

NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	190	190	0.0%	0.0%	**0.0%**
ERCOT	6,330	5,790	-8.5%	-0.7%	**-7.8%**
FRCC	7,800	7,760	-0.5%	-16.2%	**15.7%**
MAAC	2,070	2,070	0.0%	0.0%	**0.0%**
MAIN	2,760	2,760	0.0%	0.0%	**0.0%**
MAPP	330	330	0.0%	0.0%	**0.0%**
NPCC	5,820	7,980	37.1%	-1.6%	**38.7%**
SERC	6,960	6,930	-0.4%	20.6%	**-21.0%**
SPP	2,130	2,130	0.0%	0.0%	**0.0%**
WSCC	5,860	7,280	24.2%	25.6%	**-1.4%**
Total	**40,250**	**43,220**	**7.4%**	**1.9%**	**5.5%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-14: Capacity in 2013 (MW; by NERC Region)

NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	78,660	78,660	0.0%	0.0%	**0.0%**
ERCOT	43,460	43,420	-0.1%	-0.1%	**0.0%**
FRCC	24,440	24,300	-0.6%	-0.5%	**-0.1%**
MAAC	31,410	30,180	-3.9%	-0.4%	**-3.5%**
MAIN	34,140	34,140	0.0%	0.0%	**0.0%**
MAPP	14,890	14,890	0.0%	0.0%	**0.0%**
NPCC	37,290	36,040	-3.4%	-3.1%	**-0.3%**
SERC	100,780	99,050	-1.7%	-0.1%	**-1.6%**
SPP	19,990	19,990	0.0%	0.0%	**0.0%**
WSCC	30,950	29,790	-3.7%	-8.5%	**4.8%**
Total	**416,010**	**410,460**	**-1.3%**	**-1.0%**	**-0.3%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-15: Generation in 2013 (MWh; by NERC Region)

NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	533	536	0.6%	0.0%	**0.6%**
ERCOT	162	171	5.8%	0.0%	**5.8%**
FRCC	80	106	32.8%	0.0%	**32.8%**
MAAC	179	155	-13.3%	0.0%	**-13.3%**
MAIN	221	243	10.2%	0.0%	**10.2%**
MAPP	107	129	21.1%	0.0%	**21.1%**
NPCC	161	174	8.1%	-6.3%	**14.4%**
SERC	630	545	-13.4%	0.0%	**-13.4%**
SPP	109	117	7.6%	0.0%	**7.6%**
WSCC	140	114	-18.6%	-14.3%	**-4.3%**
Total	**2,321**	**2,291**	**-1.3%**	**-1.3%**	**0.0%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-16: Revenues in 2013 ($2001 Million; by NERC Region)

NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	17,320	17,600	1.6%	0.0%	**1.6%**
ERCOT	5,850	6,250	6.8%	-0.2%	**7.0%**
FRCC	3,360	4,180	24.4%	-2.2%	**26.6%**
MAAC	6,520	5,740	-12.0%	-0.8%	**-11.2%**
MAIN	7,060	7,680	8.8%	0.0%	**8.8%**
MAPP	3,160	3,910	23.7%	0.0%	**23.7%**
NPCC	6,220	6,710	7.9%	-3.2%	**11.1%**
SERC	20,690	17,950	-13.2%	0.0%	**-13.2%**
SPP	3,550	3,980	12.1%	0.0%	**12.1%**
WSCC	5,000	4,130	-17.4%	-17.2%	**-0.2%**
Total	**78,730**	**78,130**	**-0.8%**	**-1.6%**	**0.8%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-17: Variable Production Costs/MWh of Generation in 2013 (in millions, $2001; by NERC Region)

NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	11.68	11.68	0.0%	-0.1%	**0.1%**
ERCOT	15.39	15.39	0.1%	0.0%	**0.1%**
FRCC	15.11	15.05	-0.4%	0.7%	**-1.1%**
MAAC	11.41	11.62	1.9%	0.0%	**1.9%**
MAIN	11.29	11.29	0.0%	0.0%	**0.0%**
MAPP	11.08	11.08	0.0%	0.0%	**0.0%**
NPCC	17.99	18.01	0.2%	-0.2%	**0.4%**
SERC	11.18	11.14	-0.3%	0.0%	**-0.3%**
SPP	11.99	11.99	0.0%	0.0%	**0.0%**
WSCC	16.16	15.58	-3.6%	3.9%	**-7.5%**
Total	**12.56**	**12.51**	**-0.3%**	**-0.3%**	**0.0%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B8-A-18: Fuel Costs/MWh of Generation in 2013 (in millions, $2001; by NERC Region)

NERC Region	AEO Electricity Demand Assumptions			% Change with EPA Assumptions	Difference between AEO and EPA Assumptions
	Base Case	Post-Compliance	% Change		
ECAR	9.22	9.22	-0.1%	-0.1%	**0.0%**
ERCOT	12.76	12.77	0.1%	0.1%	**0.0%**
FRCC	12.60	12.50	-0.8%	0.9%	**-1.7%**
MAAC	9.24	9.45	2.3%	-0.1%	**2.4%**
MAIN	9.04	9.04	0.0%	0.0%	**0.0%**
MAPP	9.02	9.02	0.0%	0.0%	**0.0%**
NPCC	16.28	16.29	0.1%	-0.3%	**0.4%**
SERC	9.02	8.98	-0.5%	0.0%	**-0.5%**
SPP	9.80	9.80	0.0%	0.0%	**0.0%**
WSCC	14.13	13.43	-4.9%	4.3%	**-9.2%**
Total	**10.32**	**10.26**	**-0.5%**	**-0.5%**	**0.0%**

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

B8-A.2.2 Individual Phase II Facilities

In addition to effects of the two alternative options in the group of Phase II facilities, there may be shifts in economic performance among individual facilities subject to section 316(b) regulation. To assess potential distributional effects, EPA analyzed facility-specific changes in generation, production costs, capacity utilization, revenue, and operating income. For each measure, EPA determined the number of Phase II facilities that would experience an increase or a reduction within three ranges: 0 to 1 percent, 1 to 3 percent, and 3 percent or more. Excluded from this analysis were facilities that would experience significant structural changes as a result of a policy option, including partial or full closures, avoided closures, or

repowering. Table B8-A.19 presents the total number of Phase II facilities with different degrees of change in each of these measures under the waterbody/capacity-based option.

Table B8-A-19.— Operational Changes at Phase II Facilities from the Waterbody/Capacity-Based Option (2013)[a, b]

Economic Measures	Reduction			Increase			No Change
	0-1%	1-3%	> 3%	0-1%	1-3%	> 3%	
Change in Net Generation	9	20	11	3	4	14	451
Change in Variable Production Costs	7	3	2	17	22	2	373
Change in Capacity Utilization	5	4	6	10	4	8	475
Change in Total Revenue	62	21	8	64	16	22	318
Change in Operating Income	107	16	7	74	28	12	267

[a] For all measures percentages used to assign facilities to impact categories have been rounded to the nearest 10th of a percent.

[b] Of the 512 Phase II facilities, 86 facilities had zero generation in either the base case or post-compliance scenario. It was therefore not possible to calculate the change in variable production costs for these facilities. As a result, the number of facilities adds up to 426 instead of 512 for this measure. One facility had zero revenues and operating income in the base case. As such, it was not possible to calculate its change in revenue or operating income. As a result, the number of facilities adds up to 511 instead of 512 for these measures.

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Chapter C1: Case Study Introduction

Introduction

Part C of this Economic and Benefits Analysis (EBA) presents a summary of the results of the § 316(b) benefits case studies and the extrapolation of these results to other facilities nationwide. This chapter provides an overview of the case study objectives, selection, and design. *Chapter C2: Summary of Case Study Results* summarizes case study results, *Chapter C3: National Extrapolation of Baseline Economic Losses* presents the results of the national extrapolation of baseline losses, and *Chapter C4: Benefits* discusses potential economic benefits of the proposed rule based on case study results. Case study methods and results are presented in detail in the Case Study Document.

Chapter Contents

C1-1 Why Case Studies were Undertaken

It is difficult to develop a national aggregate estimate of potential economic benefits of the proposed rule, particularly since many impacts and benefits are site-specific, and there are more than 500 facilities that are in the scope of the proposed rule. However, to the extent that the impacts and benefits associated with a specific case study facility are similar to other facilities in similar environments, results can be extrapolated to other, similar sites. EPA used this approach to estimate the potential national benefits of the proposed rule.

C1-2 What Sites were Chosen and Why

The case studies were designed to capture some of the site-specific aspects of ecological and economic impacts as well as to develop information that could be extrapolated to other, similar sites to estimate national benefits. Site-specific information is critical in predicting impacts and potential benefits of the proposed rule, since existing studies demonstrate that impacts and benefits are highly variable across facilities and environmental settings. Even similar facilities on the same waterbody can have very different impacts depending on the aquatic ecosystem in the vicinity of the facility.

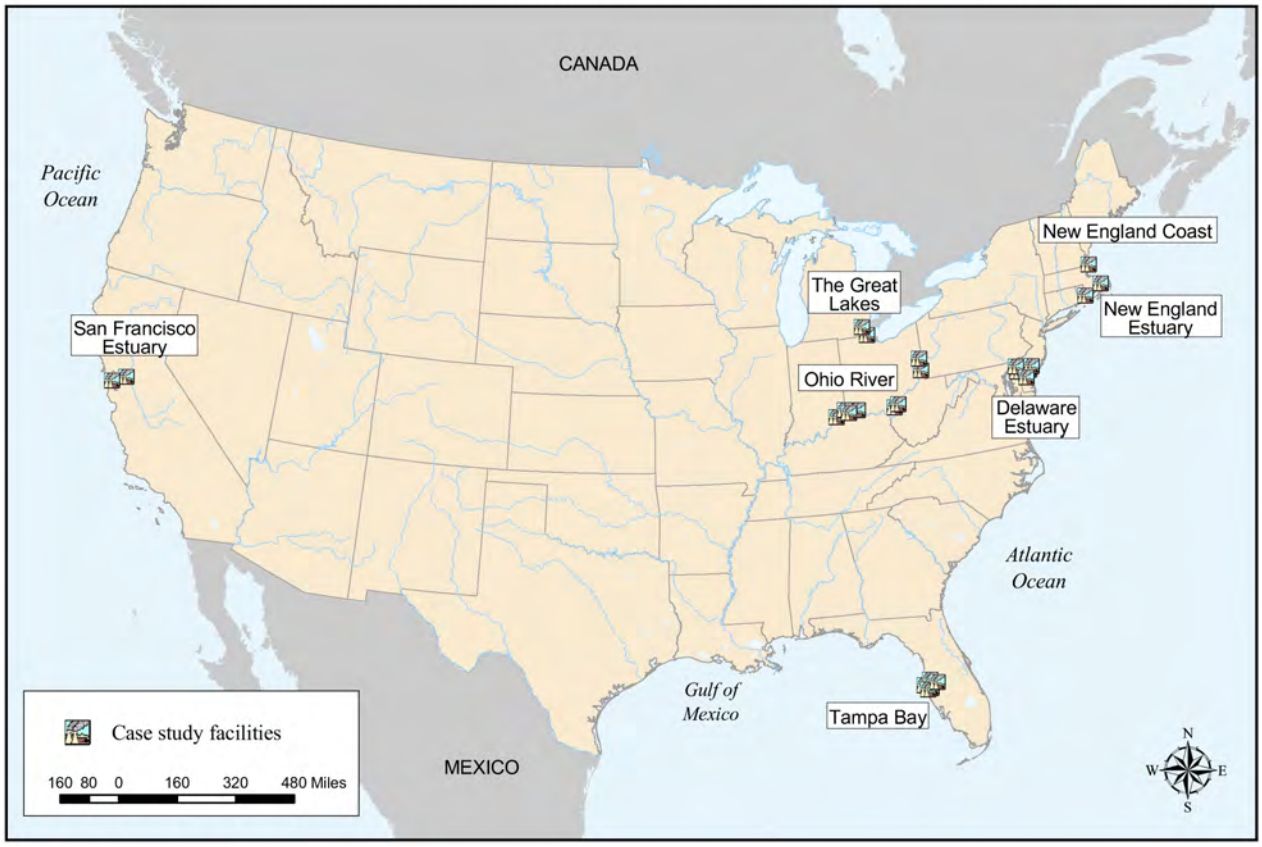
EPA selected case studies to represent a range of intake characteristics and environmental conditions throughout the United States. Important intake-specific characteristics relating to location, design, construction, and capacity include:

- Cooling water intake structure (CWIS) size and scale of operation (e.g., flow volume and velocity);
- CWIS and/or operational practices in place (if any) for impingement and entrainment(I&E) reduction at baseline (i.e., absent any new regulations);
- CWIS intake location in relation to local zones of ecological activity and significance (e.g., depth and orientation of the intake point, and its distance from shore); and
- CWIS flow volumes in relation to the size of the impacted waterbody.

Environmental factors that influence the magnitude of impacts and the potential benefits of reducing impacts include the types of waterbodies impacted, the aquatic species that are affected in those waterbodies, and the people who use and/or value the status of the water resources and aquatic ecosystems affected. The most important site-specific environmental factors are:

- The aquatic species present near a facility;
- The ages and life stages of the aquatic species present near the intakes;
- The timing and duration of species' exposure to the intakes;
- The ecological value of the impacted species in the context of the aquatic ecosystem;
- Whether any of the impacted species are threatened, endangered, or otherwise of special concern and status (e.g., depleted commercial stocks); and
- Local ambient water quality issues that may also affect the fisheries and their uses.

Figure C1-1: Location of Case Study Facilities



Source: U.S. EPA analysis, 2002.

The case study sites used for extrapolation are considered representative of the majority of steam electric generators in the United States. The map in Figure C1-1 indicates the locations of the case study facilities in relation to other facilities nationwide.

C1-3 Steps Taken in the Case Studies

Each case study was a comprehensive analysis of historical ecological impacts, potential reductions in these impacts resulting from the proposed rule, and the anticipated economic benefits of reducing impacts. Data gathering and analytical steps are described in detail in Chapter A5 of Part A of the Case Study Document and summarized below in Figure C1-2. The major steps were as follows.

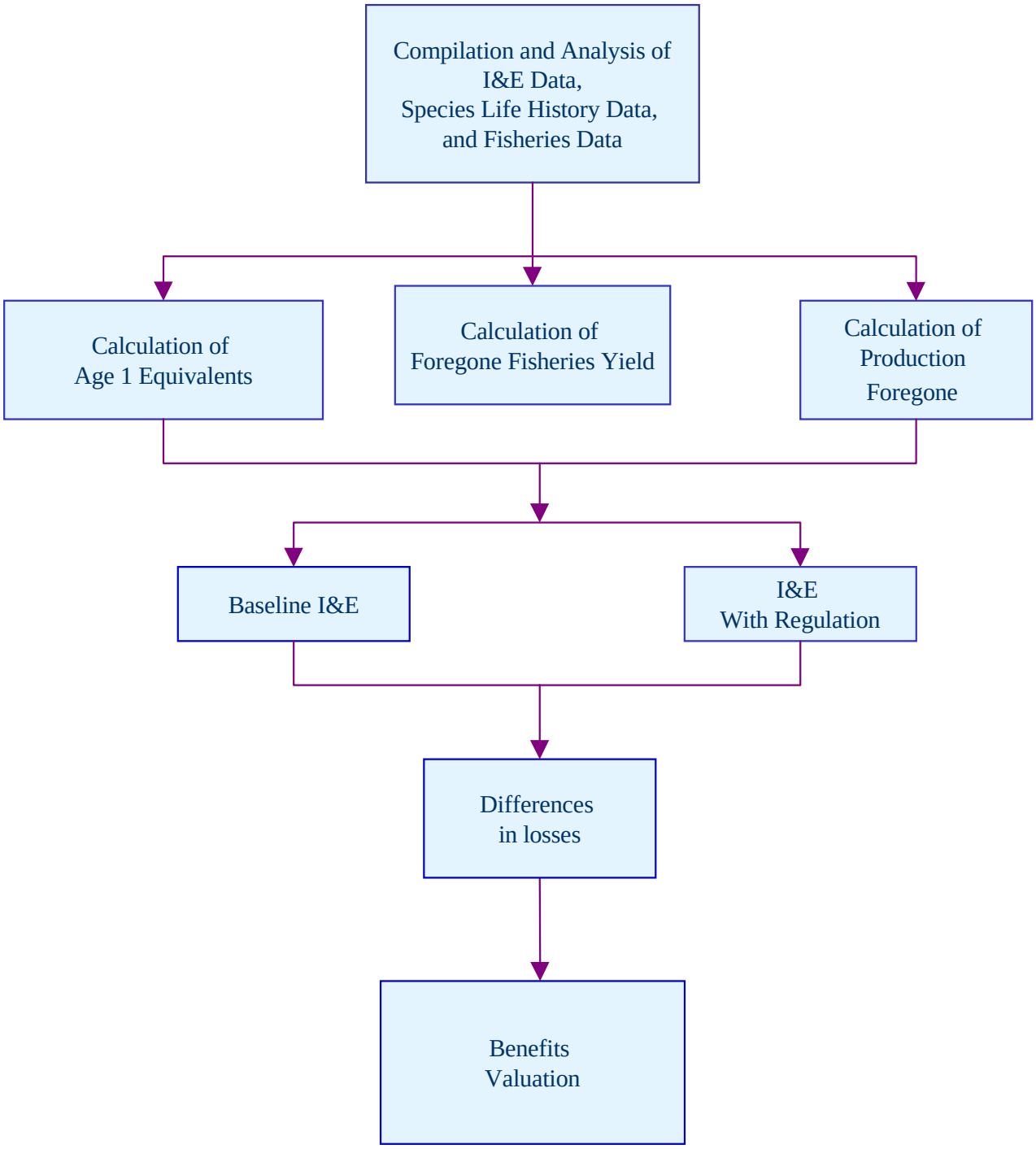
- EPA compiled any economic, technical, and biological data available from previous § 316(b) studies and from results of EPA's survey of the industry for the § 316(b) rulemaking.
- This information was supplemented as needed by data in the scientific literature and government reports on the environmental settings and socioeconomic characteristics of the case study sites.
- EPA compiled life history data from local fishery surveys, facility monitoring, and the scientific literature for all species identified as vulnerable to I&E based on previous intake or waterbody monitoring. This information was used to implement biological models to express annual counts of impinged and entrained organisms as numbers of age 1 equivalents, pounds of fishery yield, and production foregone, as described in Chapter A5 of Part A of the Case Study Document.
- Once historical I&E losses were quantified, EPA estimated potential reductions in I&E with the proposed rule, and estimated human use and nonuse benefits expected to result from the predicted reductions in I&E.

C1-4 Summary of Case Study Analyses

Table C1-1 summarizes the analyses conducted in the different case studies. Three studies (Delaware Estuary, Tampa Bay, and Ohio River) evaluated multiple CWIS within a single waterbody to develop an indication of potential cumulative impacts at the watershed scale. One study (San Francisco Estuary) examined impacts to threatened and endangered species and the potential economic benefits associated with protecting rare species. Several studies focused on discrete technology or operational alternatives such as once-through versus closed-cycle cooling (Brayton Point), offshore versus shoreline intake locations (Pilgrim and Seabrook), and use of a barrier net to reduce impingement (J.R. Whiting).

All studies applied benefits transfer techniques to estimate the economic value of losses to commercial and recreational fisheries, but several studies also applied other standard, well-accepted economic techniques that are new to the analysis of § 316(b) I&E losses to capture other economic values, including societal revealed preference techniques (San Francisco Bay/Delta), a random utility model (RUM) of recreational behavior (Delaware Estuary, Ohio River, and Tampa Bay) and habitat-based replacement cost (HRC) analysis (J.R. Whiting, Monroe, Brayton Point, and Pilgrim). The RUM approach evaluates changes in consumer valuation of water resources expected to result from reductions in I&E-related fish losses. The HRC technique assigns economic value to I&E losses based on the combined costs of implementing restoration actions to produce the organisms that were lost, administering the programs, and monitoring the production resulting from restoration actions.

Figure C1-2: Steps in § 316(b) Case Study Data Gathering and Analysis



Source: U.S. EPA analysis, 2002.

Table C1-1: Case Study Sites

Facilities Evaluated	Type of Study
CS-1: Delaware Estuary Watershed Study	
Salem Hope Creek Deepwater Edgemoor	Mid-Atlantic Estuary Watershed-Scale Study ‣ Cumulative Impacts RUM Analysis Electricity Region: MACC, Mid-Atlantic Area Council
CS-2: Tampa Bay Watershed Study	
PL Barlow FJ Gannon Hookers Point Manatee Big Bend	Southern Gulf Coast Estuary Watershed-Scale Study ‣ Cumulative Impacts RUM Analysis Electricity Region: FRCC, Florida Reliability Coordinating Council
CS.-3: Ohio River Watershed Study	
W.H. Sammis, OH Cardinal, OH Kyger Creek, OH Tanners Creek, IN Clifty Creek, IN P. Sporn, WV Kammer, WV	Large River Watershed-Scale Study ‣ Cumulative Impacts RUM Analysis Electricity Region: ECAR, East Central Area Reliability Coordination Agreement
CS-4: San Francisco Bay / Delta	
Pittsburg Contra Costa	Threatened and Endangered Species Western Estuary Societal Revealed Preference Analysis Electricity Region: WSCC, Western Systems Coordinating Council
CS-5: New England Estuary (Mount Hope Bay)	
Brayton Point	New England Estuary Fish Population Decline ‣ Once Through v. Wet Cooling Habitat-based Replacement Cost Analysis Electricity Region: NPCC, Northeast Power Coordinating Council
CS-6: New England Coast	
Seabrook Pilgrim	Intake Location Study ‣ Off-Shore v. Shoreline Habitat-based Replacement Cost Analysis of Pilgrim Electricity Region: NPCC, Northeast Power Coordinating Council
CS-7: Great Lakes	
JR Whiting	Technology Study ‣ Impingement Deterrent Net Habitat-based Replacement Cost Analysis Electricity Region: ECAR, East Central Area Reliability Coordination Agreement
CS-8: Large River Tributary to Great Lakes	
Monroe	Intake Flow Study ‣ Intake Flow exceeds the waterbody flow most of year Habitat-based Replacement Cost Analysis Electricity Region: ECAR, East Central Area Reliability Coordination Agreement

Source: U.S. EPA analysis, 2002.

C1-5 Data Uncertainties Leading to Underestimates of Case Study Impacts and Benefits

EPA's estimates of case study impacts and the potential economic benefits of the proposed rule are subject to considerable uncertainties. As a result, the Agency's estimated benefits could be either over- or underestimated. However, because of the many factors omitted from the analysis (typically because of data limitations), and the manner in which several key uncertainties were addressed, EPA believes that its analysis is likely to lead to potentially significant underestimates of baseline losses in most cases, and therefore underestimates of regulatory benefits. These factors are discussed in the Case Study Document and summarized below.

C1-5.1 Data Limitations

EPA's analysis is based on facility-provided biological monitoring data. These facility-furnished data typically focus on a subset of the fish species impacted by I&E, resulting in an underestimate of the total magnitude of losses.

Industry biological studies often lack a consistent method for monitoring I&E. Thus, there are often substantial uncertainties and potential biases in the I&E estimates. Comparison of results between studies is therefore very difficult and sometimes impossible, even among facilities that impinge and entrain the same species.

The facility-derived biological monitoring data often pertain to conditions existing many years ago (e.g., the available biological monitoring often was conducted by the facilities 20 or more years ago, before activities under the Clean Water Act had improved aquatic conditions). In those locations where water quality was relatively degraded at the time of monitoring relative to current conditions, the numbers and diversity of fish are likely to have been depressed during the monitoring period, resulting in low I&E. In most of the nation's waters, current water quality and fishery levels have improved, so that current I&E losses are likely to be greater than available estimates for depressed populations.

C1-5.2 Estimated Technology Effectiveness

I&E benefits are dependent in the technologies that are installed, the proper use of those technologies, the degree to which the technologies are maintained and repaired, and the commitment of the facility to optimizing the technologies for their given location. Potential latent mortality rates are unknown for most technologies. The only technology effectiveness that is certain is reductions in I&E with cooling towers. If the towers are running, I&E reductions can be estimated with some certainty. EPA's analyses assumes that installed technologies will be operate at the maximum efficiency assumed by EPA in its estimates of technology effectiveness. To the degree that this is not the case, benefits could be lower.

C1-5.3 Potential Cumulative Impacts

I&E impacts often have cumulative impacts that are usually not considered. Cumulative impacts refer to the temporal and spatial accumulation of changes in ecosystems that can be additive or interactive. Cumulative impacts can result from the effects of multiple facilities located within the same waterbody and from individually minor but collectively significant I&E impacts taking place over a period or time. Because of time and funding constraints, EPA was able to estimate potential cumulative impacts for only three of its case studies (Delaware Estuary, Ohio River, Tampa Bay).

Relatively low estimates of I&E impacts may reflect a situation where cumulative I&E impacts (and other stresses) have appreciably reduced fishery populations so that there are fewer organisms present in intake flows.

In many locations (especially estuary and coastal waters), many fish species migrate long distances. As such, these species are often subject to I&E risks from a large number cooling water intake structures. EPA's analyses reflect the impacts of a limited set of facilities on any given fishery, whereas many of these fish are subjected to I&E at a greater number of cooling water intake structures than are included in the boundaries of the Agency's case studies.

C1-5.4 Recreational Benefits

Recreational values were underestimated for a number of reasons. These include:

- The proportion of I&E losses of fishery species that were valued as lost recreational catch was determined from stock-specific fishing mortality rates, which indicate the fraction of a stock that is harvested. Because fishing mortality rates are typically less than 20 percent, a large proportion of the losses of fishery species was not valued in the benefits transfer and RUM analyses.

- Only selected species were evaluated because I&E or valuation data were limited.

- In applying benefits transfer to value the benefits of improved recreational angling, the Agency assigned a monetary benefit to only the increases in consumer surplus for the baseline number of fishing days. Changes in participation (except where the RUM is estimated) are not considered. Thus, benefits will be understated if participation increases in response to increased availability of fishery species as a result of reduced I&E. This approach omits the portion of recreational fishing benefits that arise when improved conditions lead to higher levels of participation. Empirical evidence suggests that the omission of increased angling days can lead to an underestimate of total recreational fishing benefits. Where EPA has been able to apply its RUM analyses, the recreational angling benefits are more indicative of the full range of beneficial angling outcomes.

C1-5.5 Secondary (indirect) Economic Impacts

Secondary impacts are not calculated (effects on marinas, bait sales, property values, and so forth are not included, even though they may be significant and applicable on a regional scale).

C1–5.6 Commercial Benefits

Commercial benefits were underestimated for the following reasons:

- The proportion of I&E losses of fishery species that were valued as lost commercial catch was determined from stock-specific fishing mortality rates, which indicate the fraction of a stock that is harvested. Because fishing mortality rates are typically less than 20 percent, a large proportion of the losses of fishery species was not valued in the benefits transfer analyses.

- In most cases, invertebrate species (e.g, lobsters, mussels, crabs, shrimp) were not included because of a lack of I&E data and/or life history information.

- I&E impacts and associated reductions in fishery yields are probably understated even for those species EPA could evaluate because of a lack of monitoring data to capture population variability and cumulative I&E impacts over time.

- Current fishing mortality rates (and resulting estimates of yield) often reflect depleted fisheries, not what the fisheries should or could be if not adversely impacted by I&E and other stressors. As such, yield estimates may be artificially low because of significantly curtailed recreational and/or commercial catch of key species impinged and entrained (e.g., winter flounder in Mount Hope Bay).

C1-5.7 Forage Species

Benefits for forage species are underestimated for many reasons. These reasons include:

- Forage species often make up the predominant share of losses due to I&E. However, I&E losses of forage species are usually not known because many facility studies focus only on commercial and recreational fishery species.

- Even when forage species are included in loss estimates, the monetary value assigned to forage species is likely to be understated because the full ecological value of the species as part of the food web is not considered.

- Forage losses are often valued at only a fraction of their potential full value because of partial "replacement" cost (even if feasible to replace).
- The value of production foregone includes only the value of added biomass to landed recreational and commercial species is considered. The inherent value of forage species is not included in the benefits estimates.
- In one valuation approach EPA applied to forage species, only a small share of these losses is valued — namely, the contribution of the forage species to the increased biomass of landed recreational and commercial species.
- This does not apply to benefits derived by the habitat-based replacement cost approach, which provides a more comprehensive indication of the benefits of reducing I&E on all species, including forage fish. EPA has applied this approach to a limited number of settings, and in those settings the findings suggest benefits appreciably greater than derived from the more conventional, partial benefits approaches applied by the Agency.

C1-5.8 Nonuse Benefits

EPA's benefit estimate of nonuse benefits is understated using the 50 percent rule because the recreational values used are likely to be understated. The 50 percent rule itself is conservative (e.g., it only reflects nonuse component of total value to recreational users; it does not reflect any nonuse benefits to recreational nonusers). In addition, the rule does not capture impacts on threatened and endangered species.

C1-5.9 Incidental Benefits

EPA's estimates of benefits are underestimates for some options because EPA has not accounted for thermal impact reductions, which will occur in all options where once-through facilities are replaced with recirculating water regimes (e.g., sites going to cooling towers).

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Appendix to Chapter C1

Introduction

In developing the national benefits estimates for *Chapter C4: Benefits*, EPA used the sample weights estimated during the sampling design for the 316(b) questionnaires. These weights were used to generate benefits estimates for all 550 in-scope facilities based on the baseline losses for 539 in-scope facilities for which questionnaire data was available. This appendix presents the unweighted benefits estimates in the tables below.

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The reported percent reduction in baseline losses for each facility reflects EPA's assessment of (1) regulatory baseline conditions at the facility (i.e., current practices and technologies in place), and (2) the percent reductions in impingement and entrainment that EPA estimated would be achieved at each facility that the Agency believes would be adopted under each regulatory option.

C1-A.1 Options with Benefit Estimates

EPA estimated benefits for the following six options. These options include:

- **Option 1:** Track I of the waterbody /capacity-based option;
- **Option 2:** Track I and II of the waterbody /capacity-based option;
- **Option 3:** (the Agency's proposed rule), impingement and entrainment controls everywhere with exceptions for low-flow facilities on lakes and rivers;
- **Option 3a:** impingement and entrainment controls everywhere with no exceptions;
- **Option 4:** requires all Phase II existing facilities to reduce intake capacity commensurate with the use of closed-cycle, recirculating cooling systems; and
- **Option 5:** requires that all Phase II existing facilities reduce intake capacity commensurate with the use of dry cooling systems.
- **Option 6:** similar to Option1, but requires reduction commensurate with the use of closed-cycle, recirculating systems for all facilities on estuaries, tidal rivers, and oceans

National estimates including weights can be found in *Chapter C4: Benefits*, and a complete description of the options detailed in the following tables can be found in Part A, Chapter A1 of this document.

C1-A.2 Impingement Reductions and Benefits

Table C1-A-1 presents the percentage reductions in impingement that are expected to occur under the six options listed above and Table C1-A-2 presents the benefit value associated with those reductions.

Table C1-A-1: Unweighted Impingement Reductions for Various Options - By Reduction Level

Waterbody Type	Number of In-Scope Facilities	Baseline Impingement Loss	Percentage Reductions						
			Option 1	Option 2	Option 3	Option 3a	Option 4	Option 5	Option 6
Estuary - Non-Gulf	78	$52,463	64.5%	47.5%	33.2%	25.0%	40.9%	97.5%	84.2%
Estuary - Gulf	30	$4,097	63.2%	45.9%	26.5%	30.0%	45.3%	96.7%	79.4%
Freshwater	393	$40,417	47.3%	47.3%	47.3%	46.7%	59.0%	98.0%	47.8%
Great Lake	16	$31,506	80.0%	80.0%	80.0%	77.0%	88.6%	96.3%	79.4%
Ocean	22	$14,174	73.2%	59.0%	50.6%	47.2%	59.7%	88.8%	78.9%
Total	**539**	**$142,656**							

Source: U.S. EPA analysis, 2002.

Table C1-A-2: Unweighted Impingement Benefits for Various Options - By Benefit Level (in thousands, $2001)

Waterbody Type	Number of In-Scope Facilities	Baseline Impingement Loss	Benefits						
			Option 1	Option 2	Option 3	Option 3a	Option 4	Option 5	Option 6
Estuary - Non-Gulf	78	$52,463	$33,834	$24,909	$17,418	$13,125	$21,470	$51,141	$44,148
Estuary - Gulf	30	$4,097	$2,588	$1,882	$1,087	$1,230	$1,856	$3,961	$3,253
Freshwater	393	$40,417	$19,117	$19,117	$19,117	$18,855	$23,828	$39,605	$19,304
Great Lake	16	$31,506	$25,205	$25,205	$25,205	$24,260	$27,900	$30,326	$25,018
Ocean	22	$14,174	$10,369	$8,359	$7,171	$6,686	$8,467	$12,585	$11,182
Total	**539**	**$142,656**	**$91,113**	**$79,472**	**$69,998**	**$64,156**	**$83,520**	**$137,619**	**$102,905**

Source: U.S. EPA analysis, 2002.

C1-A.3 Entrainment Reductions and Benefits

Table C1-A-3 presents the percentage reductions in impingement that are expected to occur under the six options listed above and Table C1-A-4 presents the benefit value associated with those reductions.

Table C1-A-3: Unweighted Entrainment Benefits for Various Options - By Reduction Level

Waterbody Type	Number of In-Scope Facilities	Baseline Entrainment Loss	Entrainment Percentage Reductions						
			Option 1	Option 2	Option 3	Option 3a	Option 4	Option 5	Option 6
Estuary - Non-Gulf	78	$876,002	67.2%	59.1%	48.5%	47.1%	79.2%	97.5%	78.0%
Estuary - Gulf	30	$103,593	66.9%	52.3%	47.0%	47.8%	79.3%	96.7%	78.3%
Freshwater	393	$95,660	12.4%	12.4%	12.4%	44.2%	72.7%	98.0%	9.8%
Great Lake	16	$43,448	57.8%	57.8%	57.8%	57.8%	88.6%	96.3%	57.3%
Ocean	22	$259,656	74.2%	58.9%	45.0%	45.0%	74.1%	88.8%	74.1%
Total	**539**	**$1,378,359**							

Source: U.S. EPA analysis, 2002.

Table C1-A-4: Unweighted Entrainment Benefits for Various Options - By Benefit Level (in thousands, $2001)

Waterbody Type	Number of In-Scope Facilities	Baseline Entrainment Loss	Entrainment Benefit						
			Option 1	Option 2	Option 3	Option 3a	Option 4	Option 5	Option 6
Estuary - NonGulf	78	$876,002	$588,552	$517,960	$424,708	$412,696	$693,420	$853,940	$683,494
Estuary - Gulf	30	$103,593	$69,324	$54,206	$48,645	$49,508	$82,186	$100,175	$81,160
Freshwater	393	$95,660	$11,883	$11,883	$11,883	$42,277	$69,575	$93,738	$9,410
Great Lake	16	$43,448	$25,092	$25,092	$25,092	$25,092	$38,474	$41,820	$24,899
Ocean	22	$259,656	$192,560	$152,869	$116,796	$116,796	$192,296	$230,553	$192,296
Total	**539**	**$1,378,359**	**$887,410**	**$762,010**	**$627,123**	**$646,368**	**$1,075,951**	**$1,320,227**	**$991,259**

Source: U.S. EPA analysis, 2002.

C1-A.4 Benefits Associated with Various Percentage Reductions

Table C1-A-5 presents the national benefits that would occur with various percentage reductions.

Table C1-A-5: Summary of Unweighted Potential Benefits Associated with Various Impingement and Entrainment Reduction Levels (All 539 In-Scope Facilities)

Reduction Level	Benefits (in thousands, $2001)	
	Impingement	Entrainment
10%	$14,266	$137,836
20%	$28,531	$275,672
30%	$42,797	$413,508
40%	$57,063	$551,344
50%	$71,328	$689,180
60%	$85,594	$827,016
70%	$99,859	$964,851
80%	$114,125	$1,102,687
90%	$128,391	$1,240,523

Source: U.S. EPA analysis, 2002.

C1-A.5 Benefits Associated with the Proposed Option

Table C1-A-6 presents the benefits that would occur with various percentage reductions

Table C1-A-6: Summary of Unweighted Potential Benefits from Impingement and Entrainment Controls Associated with the Proposed Rule (Option 3)

Waterbody Type	Number of In-Scope Facilities	Benefits (in thousands, $2001)	
		Impingement	Entrainment
Estuary - NonGulf	78	$17,418	$424,708
Estuary - Gulf	30	$1,087	$48,645
Freshwater	393	$19,117	$11,883
Great Lake	16	$25,205	$25,092
Ocean	22	$7,171	$116,796
Total	**539**	**$69,998**	**$627,123**

Source: U.S. EPA analysis, 2002.

Under today's proposal, facilities can choose the Site-Specific Determination of Best Technology Available in § 125.94(a) in which a facility can demonstrate to the Director that the cost of compliance with the applicable performance standards in § 125.94(b) would be significantly greater than the costs considered by EPA when establishing these performance standards, or the costs would be significantly greater than the benefits of complying with these performance standards. EPA expects that if facilities were to choose this approach, then the overall national benefits of this rule will decrease markedly. This is because under this approach facilities would choose the lowest cost technologies possible and not necessarily the most effective technologies to reduce impingement and entrainment at the facility. See *Chapter C4: Benefits* for additional information on the certainty of each of the other options.

Chapter C2: Summary of Case Study Results

Introduction

This chapter summarizes the results of the eight case study analyses. Each case study section reports EPA's estimate of the number of age 1 equivalent fish that are lost to I&E at the case study facilities and the economic value of these losses. The final section presents EPA's extrapolation of the losses from five case studies to estimates of national I&E losses.

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C2-1 The Delaware Estuary Watershed Study (Mid-Atlantic Estuaries)

To evaluate potential I&E impacts of cooling water intake structures in the Delaware Estuary transition zone, EPA evaluated I&E rates at Salem Nuclear Generating Station located in the transition zone of the Delaware Estuary. EPA estimated that the impingement impact of Salem Nuclear Generating Station is over 3.1 million age 1 equivalent fish and over 135,900 pounds of lost fishery yield per year. The entrainment impact is over 356.3 million age 1 equivalent fish and 9.9 million pounds of lost fishery yield. Extrapolation of these losses to four other facilities indicated a cumulative impingement impact of over 12.2 million age 1 fish and a cumulative entrainment impact of over 526 million age 1 equivalent fish each year (Table C2-1). These results indicate that the cumulative impacts of multiple cooling water intake structures (CWIS) in a single area can be substantial.[1]

Table C2-1: Baseline Impacts (annual average) for the Delaware Estuary Transition Zone (Four In-Scope Facilities)

Baseline Impacts	Impingement	Entrainment
Age 1 equivalent fish lost	>12.2 million/yr	> 526.3 million/yr
# lbs lost to landed fishery	> 374,000 lb/yr	> 13.8 million lb/yr
$ value of loss ($2001)	$0.50 million - $0.8 million/yr	$16.8 million - $30.5 million/yr

Source: U.S. EPA analysis, 2002.

Average losses at the four in-scope facilities are valued (using benefits transfer combined with RUM recreation estimates) to range from $0.5 million to $0.8 million per year for impingement and from $16.8 to $30.5 million per year for entrainment (all in $2001).

[1] For an estimation of lost fishery yield per year and age 1 equivalent fish each year, see *Chapter B3: Ecological Risk Assessment* in *Part B:The Delaware Estuary* of the *Watershed Case Study Analysis for the Proposed Section 316(b) Phase II Existing Facilities Rule*.

In this estuarine setting, benefits attributed to reducing losses due to both impingement and entrainment may be quite large in terms of numbers of fish and in terms of the portion of benefits that could be monetized. This reflects the typical richness of estuary waters as important nursery locations for many important aquatic species. In addition, the higher benefit associated with entrainment reflects the high vulnerability of abundant early life stages of estuarine species, and indicates the relative importance of entrainment controls in estuary areas.

In part, EPA's recreational benefits estimates for the Delaware Estuary are based on a random utility model (RUM) analysis of recreational fishing benefits from reduced I&E. The RUM application in the Delaware Estuary focuses on weakfish and striped bass fishing valuation. Several recreational fishing studies have valued weakfish and striped bass, but values specific to these studies are not available. The study area includes recreational fishing sites at the Delaware River Estuary and the Atlantic coasts of Delaware and New Jersey.

EPA used data for this case study from the Marine Recreational Fishery Statistics Survey (MRFSS), combined with the 1994 Add-on MRFSS Economic Survey (AMES). The study used MRFSS information on angler characteristics and angler preferences, such as where they go fishing and what species they catch, to infer their values for changes in recreational fishing quality. EPA estimated angler behavior using a RUM for single-day trips. The study used standard assumptions and specifications of the RUM model that are readily available from the recreation demand literature. Among these assumptions are that anglers choose fishing mode and then the site in which to fish; and that anglers' choice of target species is exogenous to the model. EPA modeled an angler's decision to visit a site as a function of site-specific cost, fishing trip quality, presence of boat launching facilities, and water quality.

The quality of a recreational fishing trip is expressed in terms of the number of fish caught per hour of fishing. Catch rate is the most important attribute of a fishing site from the angler's perspective. This attribute is also a policy variable of concern because catch rate is a function of fish abundance, which may be affected by fish mortality caused by I&E.

The Agency combined the estimated model coefficients with the estimated changes in I&E associated with various cooling water intake structure technologies to estimate per trip welfare losses from I&E at the cooling water intake structures located in the Delaware Estuary transition zone. The estimated economic values of recreational losses from I&E at the 12 cooling water intake structures located in the case study area are $0.75, $2.04, and $9.97 per trip for anglers not targeting any particular species and anglers targeting weakfish and striped bass, respectively (all in $2001). EPA then estimated benefits of reducing I&E of two species — weakfish and striped bass — at the four in-scope cooling water intake structures in the case study area. The estimated values of an increase in the quality of fishing sites from reducing I&E at the in-scope cooling water intake structures are $0.52, $1.40 and $6.90 per trip for no target anglers and anglers targeting weakfish and striped bass, respectively (all in $2001).

EPA also examined the effects of changes in fishing circumstances on fishing participation during the recreational season. First, the Agency used the negative binomial form of the Poisson model to model an angler's decision concerning the number of fishing trips per recreation season. The number of fishing trips is modeled as function of the individual's socioeconomic characteristics and estimates of individual utility derived from the site choice model. The Agency then used the estimated model coefficients to estimate percentage changes in the total number of recreational fishing trips due to improvements in recreational site quality. EPA combined fishing participation data for Delaware and New Jersey obtained from MFRSS with the estimated percentage change in the number of trips under various policy scenarios to estimate changes in total participation stemming from changes in the fishing site quality in the study area. The MRFSS fishing participation data include information on both single-day and multiple-day trips. The Agency assumed that per day welfare gain from improved fishing site quality is independent of trip length. EPA therefore calculated total fishing participation for this analysis as the sum of the number of single-day trips and the number of fishing days corresponding to multiple-day trips. Analysis results indicate that improvements in fishing site quality from reducing I&E at all in-scope facilities will increase the total number of fishing days in Delaware and New Jersey by 9,464.

EPA combined fishing participation estimates with the estimated per trip welfare gain under various policy scenarios to estimate the value to recreational anglers of changes in catch rates resulting from changes in I&E in the Delaware Estuary transition zone. EPA calculated low and high estimates of economic values of recreational losses from I&E by multiplying the estimated per trip welfare gain by the baseline and policy scenario number of trips, respectively. The estimated recreational losses ($2001) to Delaware and New Jersey anglers from I&E of two species at all Phase 2 facilities in the transitional estuary and at all facilities in the transitional estuary range from $0.2 to $0.3 and from $7.2 to $13.2 million, respectively. Using similar calculations, the Agency estimated that reducing I&E of weakfish and striped bass at the four in-scope cooling water intake structures in the transition zone will generate $5.2 to $9.3 million ($2001) annually in recreational fishing benefits alone to Delaware and New Jersey anglers.

In interpreting the results of the Delaware case study, it is important to consider several critical caveats and limitations of the analysis. First, EPA believes that it has conservatively estimated cumulative impacts on Delaware Estuary species by considering only the I&E impacts of transition zone cooling water intake structures. In fact, many of the species affected by cooling water intake structures within the transition zone move in and out of this area, and therefore may be exposed to many more cooling water intake structures than considered here.

Second, the economic valuation of I&E losses is often complicated by the lack of market value for forage species, which may comprise a large proportion of total losses. EPA estimates that more than 450 million age 1 equivalents of bay anchovy may be lost to entrainment at transition zone cooling water intake structure each year (over 85 percent of the total of over 526 million estimated lost age 1 individuals for all species combined). Bay anchovy has no direct market value, but it is nonetheless a critical component of estuarine food webs. EPA included forage species impacts in the economic benefits calculations, but the final estimates may well underestimate the full value of the losses imposed by I&E. Thus, on the whole, EPA believes the estimates developed here probably understate the economic benefits of reducing I&E in the Delaware Estuary transition zone.

C2-2 Tampa Bay Watershed Study (Gulf Coast Estuary)

To evaluate potential I&E impacts of cooling water intake structures in estuaries of the Gulf Coast and Southeast Atlantic, EPA evaluated I&E rates at the Big Bend facility in Tampa Bay. EPA estimated that the impingement impact of Big Bend is 420,000 age 1 equivalent fish and over 11,000 pounds of lost fishery yield per year. The entrainment impact is 7.71 billion age 1 equivalent fish and nearly 23 million pounds of lost fishery yield per year. Extrapolation of these losses to other Tampa Bay facilities indicated a cumulative impingement impact of 1 million age 1 fish (27,000 pounds of lost fishery yield) and a cumulative entrainment impact of 19 billion age 1 equivalent fish (56 million pounds of lost fishery yield) each year.

The results of EPA's evaluation of the dollar value of I&E losses at Big Bend, as calculated using benefits transfer, indicate that baseline economic losses range from $60,000 to $66,000 per year for impingement and from $7.1 million to $7.3 million per year for entrainment (all in $2001). Baseline economic losses using benefits transfer for all in-scope facilities in Tampa Bay (Big Bend, PL Bartow, FJ Gannon, and Hookers Point) range from $150,000 to $163,000 per year for impingement and from $17.0 million to $18.0 million per year for entrainment (all in $2001).

EPA also developed a RUM approach to estimate the effects of improved fishing opportunities due to reduced I&E in the Tampa Bay Region. Cooling water intake structures withdrawing water from Tampa Bay impinge and entrain many of the species sought by recreational anglers. These species include spotted seatrout, black drum, sheepshead, pinfish, and silver perch. The study area includes Tampa Bay itself and coastal sites to the north and south of Tampa Bay.

The study’s main assumption is that anglers will get greater satisfaction, and thus greater economic value, from sites where the catch rate is higher, all else being equal. This benefit may occur in two ways: first, an angler may get greater enjoyment from a given fishing trip when catch rates are higher, and thus get a greater value per trip; second, anglers may take more fishing trips when catch rates are higher, resulting in greater overall value for fishing in the region.

EPA’s analysis of improvements in recreational fishing opportunities in the Tampa Bay Region relied on a subset of the 1997 MRFSS combined with the 1997 AMES and the follow-up telephone survey for the southeastern United States. The Agency evaluated five species and species groups in the model: drums (including red and black drum), spotted seatrout, gamefish, snapper-grouper, and all other species. I&E was found to affect black drum, spotted seatrout, and sheepshead, which is included in the snapper-grouper species category.

EPA estimated both a random utility site choice model and a negative binomial trip participation model. The random utility model assumes that anglers choose the site that provides them with the greatest satisfaction, based on the characteristics of different sites and the travel costs associated with visiting different sites. The trip participation model assumes that the total number of trips taken in a year are a function of the value of each site to the angler and characteristics of the angler.

To estimate changes in the quality of fishing sites under different policy scenarios, EPA relied on the recreational fishery landings data by state and the estimates of recreational losses from I&E on the relevant species at the Tampa Bay CWISs. The Agency estimated changes in the quality of recreational fishing sites under different policy scenarios in terms of the percentage change in the historical catch rate. EPA divided losses to the recreational fishery from I&E by the total recreational landings for the Tampa Bay area to calculate the percentage change in historical catch rate from baseline losses (i.e., eliminating I&E completely).

The results show that anglers targeting black drum have the largest per-trip welfare gain ($7.18 in $2001) from eliminating I&E in the Tampa region. Anglers targeting spotted seatrout and sheepshead have smaller per-trip gains ($1.80 and $1.77 respectively, in $2001). The large gains for black drum are due to the large predicted increase in catch rates. In general, based on a hypothetical one fish per trip increase in catch rate, gamefish and snapper-grouper are the most highly valued fish in the study area, followed by drums and spotted seatrout.

EPA calculated total economic values by combining the estimated per trip welfare gain with the total number of trips to sites in the Tampa Bay region. EPA used the estimated trip participation model to estimate the percentage change in the number of fishing trips with the elimination of I&E. These estimated percentage increases are 0.93 percent for anglers who target sheepshead,0 .94 percent for anglers who target spotted seatrout, and 3.82 percent for anglers who target black drum.

If I&E were eliminated in the Tampa region, EPA estimated total benefits to be $2,428,000 per year at the baseline number of trips, and $2,458,000 per year at the predicted increased number of trips (all in $2001). At the baseline number of trips, the I&E benefits to black drum anglers are $270,000 per year; benefits to spotted seatrout anglers are $2,016,000 per year; and benefits to sheepshead anglers are $143,000 per year (all in $2001).

EPA merged the results for the RUM analysis with the benefits transfer-based estimates to create an estimate of recreational fishery losses from I&E in a manner that avoids double counting of the recreation impacts. Baseline economic losses combining both approaches for all in-scope facilities in Tampa Bay (Big Bend, PL Bartow, FJ Gannon, and Hookers Point) range from $0.80 million to $0.82 million per year for impingement and from $20.0 million to $20.9 million per year for entrainment (all in $2001) (see Table C2-2).

For a variety of reasons, EPA believes that the estimates developed here underestimate the value of I&E losses at Tampa Bay facilities. EPA assumed that the effects of I&E on fish populations are constant over time (i.e., that fish kills do not have cumulatively greater impacts on diminished fish populations). EPA also did not analyze whether the number of fish affected by I&E would increase as populations increase in response to improved water quality or other improvements in environmental conditions. In the economic analyses, EPA also assumed that fishing is the only recreational activity affected.

Table C2-2: Baseline Impacts (annual average) for Tampa Bay (Four In-Scope Facilities)

Baseline Impacts	Impingement	Entrainment
Age 1 equivalent fish lost	> 1 million/yr	> 19 billion/yr
# lbs lost to landed fishery	> 27,000 lb/yr	> 56 million lb/yr
$ value of loss ($2001)	$0.80 million - $0.82 million/yr	$20.0 million - $20.9 million/yr

Source: U.S. EPA analysis, 2002.

C2-3 Ohio River Watershed Study (Large Rivers)

Using facility-generated data, EPA evaluated the impacts of I&E along a 500-mile stretch of the Ohio River, from the western portion of Pennsylvania, along the southern border of Ohio, and into eastern Indiana. EPA evaluated the available I&E monitoring data at nine case study facilities (W.C. Beckjord, Cardinal, Clifty Creek, Kammer, Kyger Creek, Miami Fort, Philip Sporn, Tanners Creek, and WH Sammis) and extrapolated the results to the 20 remaining in-scope facilities in the case study area to derive a cumulative impact estimate for all facilities subject to the proposed rule. The extrapolations were made on the basis of relative operating size (operating MGD) and by river pool (Hannibal, Markland, McAlpine, New Cumberland, Pike Island, and Robert C. Byrd pools).

The results indicate that impingement at the nine case study facilities causes the mortality of approximately 188,000 age 1 equivalents of fishery species per year. This translates into over 9,000 pounds of lost fishery yield annually. In addition, over 6.1 million age 1 equivalents of forage species are impinged each year at the nine case study facilities. For entrainment, the results indicate that about 2.2 million age 1 equivalents of fishery species are lost each year, amounting to some 47,000 pounds of lost fishery yield annually. Entrainment of forage species results in losses of an additional 14.7 million age 1 equivalents each year.

EPA extrapolated loss rates per MGD of intake flow for the nine case study facilities to all other in-scope cooling water intake structures in the Ohio River case study area on the basis of intake flow to estimate the total baseline economic value of I&E at Ohio River facilities. The economic value of these losses is based on benefits transfer-based values applied to losses to the recreational fishery, nonuse values, and the partial value of forage species impacts (measured as replacement costs or production foregone). Average historical losses from all in-scope facilities in the case study area for impingement are valued using benefits transfer at between roughly $0.1 million and $1.4 million per year (in $2001). Average historical losses from entrainment are valued using benefits transfer at between approximately $0.8 million and $2.4 million per year (all in $2001) for in-scope facilities.

EPA also estimated a random utility model to provide primary estimates of the recreational fishery losses associated with I&E in the Ohio River case study area. This primary research results supplement the benefits transfer estimates derived by EPA. The average annual recreation-related fishery losses at all facilities in the case study amount to approximately $8.4 million (in $2001) per year (I&E impacts combined). For the in-scope facilities covered by the proposed Phase 2 rule, the losses due to I&E were estimated via the RUM to amount to approximately $8.3 million per year (in $2001). Results for the RUM analysis were merged with the benefits transfer-based estimates in a manner that avoids double counting, and indicate that baseline losses at in-scope facilities amount to between $3.5 million and $4.7 million per year for impingement and between $9.3 and $9.9 million per year for entrainment (in $2001) (see Table C2-3).

Table C2-3: Baseline Impacts (annual average) in the Ohio River (29 In-Scope Facilities)

Baseline Impacts	Impingement	Entrainment
Age 1 equivalent fish lost	> 11.3 million/yr	> 23.0 million/yr
# lbs lost to landed fishery	> 14,900lb/yr	> 39,000lb/yr
$ value of loss ($2001)	$3.5 million - $4.7 million/yr	$9.3 million - $9.9 million/yr

Source: U.S. EPA analysis, 2002.

In interpreting the results of the case study analysis, it is important to consider several critical caveats and limitations of the analysis. In the economic valuation component of the analysis, valuation of I&E losses is often complicated by the lack of market value for forage species, which may comprise a large proportion of total losses. Forage species have no direct market value, but are nonetheless a critical component of aquatic food webs. EPA included forage species impacts in the economic benefits calculations, but because techniques for valuing such losses are limited, the final estimates may well underestimate the full ecological and economic value of these losses.

In addition, the Ohio River case study is intended to reflect the level of I&E, and hence the benefits associated with reducing I&E impacts, for cooling water impact structures along major rivers of the United States. However, there are several factors that suggest that the Ohio River case study findings may be a low-end scenario in terms of estimating the benefits of the proposed regulation at facilities along major inland rivers of the United States. These factors include the following:

- The I&E data developed by the facilities were limited to one year only, are from 1977 (nearly 25 years ago), and pertain to a period of time when water quality in the case study area was worse than it is currently. This suggests that the numbers of impinged and entrained fish today (the regulatory baseline) would be appreciably higher than observed in the data collection period. In addition, the reliance on a monitoring period of one year or less implies that the naturally high variability in fishery populations is not captured in the analysis, and the results may reflect a year of below average I&E.

- The Ohio River is heavily impacted by numerous significant anthropocentric stressors in addition to I&E. The river's hydrology has been extensively modified by a series of 20 dams and pools, and the river also has been extensively impacted by municipal and industrial wastewater discharges along this heavily populated and industrialized corridor. To the degree to which these multiple stressors were atypically extensive along the Ohio River (in 1977) relative to those along other cooling water intake structure-impacted rivers in the United States (in 2002), the case study will yield smaller than typical I&E impact estimates.

- The Ohio River is very heavily impacted by cumulative effects of I&E over time and across a large number of cooling water intake structures. The case study segment of the river has 29 facilities that are in-scope for the Phase 2 rulemaking, plus an additional 19 facilities that are out of scope. Steam electric power generation accounted for 5,873 MGD of water withdrawal from the river basin, more than 90 percent of the total surface water withdrawals, according to 1995 data from USGS.

Because of these circumstances on the Ohio River, the results EPA obtained for this case study may not underestimate I&E and regulatory benefits on other inland rivers.

In conclusion, several issues and limitations in the I&E data for the Ohio case study (e.g., the reliance on data for one year, nearly 25 years ago), and the many stressors that affect the river (especially in the 1977 time frame), suggest that the results obtained by EPA underestimate the benefits of the rule relative to current Ohio River conditions. The results are also likely to underestimate the benefits value of I&E reductions at other inland river facilities.

C2-4 San Francisco Bay/Delta (Pacific Coast Estuaries)

The results of EPA's evaluation of I&E of striped bass and threatened and endangered and other special status fish species at the Pittsburg and Contra Costa facilities in the San Francisco Bay/Delta demonstrate the significant economic benefits that can be achieved if losses of highly valued species are reduced by the proposed section 316(b) rule. The benefits were estimated by reference to other programs already in place to protect and restore the declining striped bass population and threatened and endangered fish species of the San Francisco Bay/Delta region. The special status species that were evaluated included delta smelt, threatened and endangered runs of chinook salmon and steelhead, sacramento splittail, and longfin smelt.

Based on limited facility data, EPA estimated that the striped bass recreational catch is reduced by about 27,203 fish per year because of impingement at the two facilities and 185,073 fish per year because of entrainment. Estimated impingement losses of striped bass are valued at between $379,000 and $589,000 per year, and estimated entrainment losses are valued at between $2.58 million to $4.01 million per year (all in $2001).

EPA estimated that the total loss of special status fish species at the two facilities is over 431,700 age 1 equivalents per year resulting from impingement and 2.2 million age 1 equivalents per year because of entrainment. Estimated impingement losses of these species are valued at between $12.38 million and $42.65 million per year, and estimated entrainment losses are valued at between $23.1 million and $79.2 million per year (all in $2001).

The estimated value of the recreational losses and the special status species losses combined ranges from $12.8 million to $43.2 million per year for impingement and from $25.6 million to $83.2 million per year for entrainment (all in $2001) (see Table C2-4).

Table C2-4: Baseline Impacts (annual average) for Special Status Fish Species in the San Francisco Bay/Delta (Two In-Scope Facilities)

Baseline Impacts	Impingement	Entrainment
Age 1 equivalent fish lost	> 431,700/yr	> 2..2 million/yr
Number of striped bass lost to recreational catch	27,203	185,073
$ value of combined loss ($2001)	$12.8 million - $43.2 million/yr	$25.6 million - $83.2 million/yr

Source: U.S. EPA analysis, 2002.

In interpreting these results, it is important to consider several critical caveats and limitations of the analysis. No commercial fisheries losses or non-special status forage species losses are included in the analysis. Recreational losses are analyzed only for striped bass. There are also uncertainties about the effectiveness of restoration programs in terms of meeting special status fishery outcome targets.

It is also important to note that under the Endangered Species Act, losses of all life stages of endangered fish are of concern, not simply losses of adults. However, because methods are unavailable for valuing losses of fish eggs and larvae, EPA valued the losses of threatened and endangered species based on the estimated number of age 1 equivalents that are lost. Because the number of age 1 equivalents can be substantially less than the original number of eggs and larvae lost to I&E, and because the life history data required to calculate age 1 equivalent are uncertain for these rare species, this method of quantifying I&E losses may result in an underestimate of the true benefits to society of section 316(b) regulation.

C2-5 Mt Hope Bay Point (New England Estuary)

EPA evaluated cumulative I&E impacts at the Brayton Point Station facility in Mount Hope Bay in Somerset, Massachusetts. EPA estimates that the cumulative impingement impact is 69,300 age 1 equivalents and 5,100 pounds of lost fishery yield per year. The cumulative entrainment impact amounts to 3.8 million age 1 equivalents and 70,400 pounds of lost fishery yield each year.

The results of EPA's evaluation of the dollar value of I&E losses at Brayton Point (as calculated using benefits transfer) indicate that baseline economic losses range from $7,000 to $12,000 per year for impingement and from $166,000 to $303,000 per year for entrainment (all in $2001).

EPA also developed an HRC analysis to examine the costs of restoring I&E losses at Brayton Point. These HRC estimates were merged with the benefits transfer results to develop a more comprehensive range of loss estimates. The HRC results were used as an upper bound and the midpoint of the benefits transfer method was used as a lower bound (HRC annualized at 7 percent over 20 years). Combining both approaches, the value of I&E losses at Brayton Point ranges from approximately $9,000 to $890,00 per year for impingement, and from $0.2 million to $28.3 million per year for entrainment (all in $2001) (see Table C2-5).

Table C2-5: Baseline Impacts (annual average) in Mount Hope Bay (One In-Scope Facility: Brayton Point)

Baseline Impacts	Impingement	Entrainment
Age 1 equivalent fish lost	> 69,300/yr	> 3.8 million/yr
# lbs lost to landed fishery	> 5,100 lb/yr	> 70,400 lb/yr
$ value of loss ($2001)	$9,000 - $890,000/yr	$0.2 mil - $28.3 million/yr

Source: U.S. EPA analysis, 2002.

For a variety of reasons, EPA believes that the estimates developed here underestimate the total economic benefits of reducing I&E at Brayton Point. EPA assumed that the effects of I&E on fish populations are constant over time (i.e., that fish kills do not have cumulatively greater impacts on diminished fish populations). EPA also did not analyze whether the number of fish affected by I&E would increase as populations increase in response to improved water quality or other improvements in environmental conditions. In the economic analyses, EPA also assumed that fishing is the only recreational activity affected.

C2-6 Oceans (New England Coast)

To evaluate potential I&E impacts of cooling water intake structures in oceans of the New England Coast, EPA evaluated I&E rates at the Pilgrim and Seabrook Nuclear Power Plants. EPA estimated that the impingement impact of Seabrook is over 13,000 age 1 equivalent fish and over 1,800 pounds of lost fishery yield per year. The entrainment impact is over 4.5 million age 1 equivalent fish and over 29,300 pounds of lost fishery yield per year. The impingement impact of Pilgrim is over 52,700 age 1 equivalent fish and over 4,200 pounds of lost fishery yield per year. The entrainment impact is over 14.3 million age 1 equivalent fish and over 91,000 pounds of lost fishery yield per year.

EPA's evaluation of I&E rates at Seabrook and Pilgrim indicates that I&E at Seabrook's offshore intake is substantially less than I&E at Pilgrim's nearshore intake. Impingement per MGD averages 68 percent less at Seabrook and entrainment averages 58 percent less. The species most commonly impinged at both facilities are primarily winter flounder, Atlantic herring, Atlantic menhaden, and red hake. These are species of commercial and recreational interest. However, the species most commonly entrained at the facilities are predominately forage species. Because it is difficult to assign an economic value to such losses, and because entrainment losses are much greater than impingement losses, the benefits of an offshore intake or other technologies that may reduce I&E at these facilities are likely to be underestimated. Several important factors in addition to the intake location (nearshore versus offshore) complicate the comparison of I&E at the Seabrook facility to I&E at Pilgrim (e.g., entrainment data are based on different flow regimes, different years of data collection, and protocols for reporting monitoring results).

Average impingement losses at Seabrook are valued at between $3,500 and $5,200 per year, and average entrainment losses are valued at between $142,000 and $315,000 per year (all in $2001) (see Table C2-6). Average impingement losses at Pilgrim are valued at between $3,300 and $5,000 per year, and average entrainment losses are valued at between $523,500 and $759,300 per year (all in $2001). These values reflect estimates derived using benefits transfer.

Table C2-6: Baseline Impacts (annual average) in Oceans of the New England Coast (One In-Scope Facility: Seabrook)

Baseline Impacts	Impingement	Entrainment
Age 1 equivalent fish lost	> 13,000	> 4.5 million/yr
# lbs lost to landed fishery	> 1,800 lb/yr	> 29,300 lb/yr
$ value of loss ($2001)	$3,000 - $5,000	$142,000 - $315,000

Source: U.S. EPA analysis, 2002.

EPA also developed an HRC analysis to examine the costs of restoring I&E losses at Pilgrim. Using the HRC approach, the value of I&E losses at Pilgrim is approximately $507,000 for impingement, and over $9.3 million per year for entrainment (HRC annualized at 7 percent over 20 years) (all in $2001). These HRC estimates were merged with the benefits transfer results to develop a more comprehensive range of loss estimates.

These HRC estimates were merged with the benefits transfer results to develop a more comprehensive range of loss estimates. The HRC results were used as an upper bound and the midpoint of the benefits transfer method was used as a lower bound (HRC annualized at 7 percent over 20 years). Combining both approaches, the value of I&E losses at Pilgrim ranges from approximately $4,000 to $507,00 per year for impingement, and from $0.6 million to $9.3 million per year for entrainment (all in $2001) (see Table C2-7).

Table C2-7: Baseline Impacts (annual average) in Oceans of the New England Coast (One In-Scope Facility: Pilgrim)

Baseline Impacts	Impingement	Entrainment
Losses Using Benefits Transfer		
Age 1 equivalent fish lost	> 52,700 million/yr	> 214.3 million/yr
# lbs lost to landed fishery	> 4,200 lb/yr	> 91,000lb/yr
$ value of loss ($2001)	$3,000 - $5,000/yr	$0.5 million - $0.7 million/yr
Losses Using HRC as Upper Bounds and Benefits Transfer Midpoints as Lower		
Age 1 equivalent fish lost	> 52,700/yr	> 14.3 million/yr
# lbs lost to landed fishery	> 4,200lb/yr	> 91,000 lb/yr
$ value of loss ($2001)	$4,000 - $507,000/yr	$0.6 million - $9.3 million/yr

Source: U.S. EPA analysis, 2002.

C2-7 The Great Lakes

To evaluate potential I&E impacts of cooling water intake structures in the Great Lakes, EPA evaluated I&E rates at J.R.Whiting. EPA estimated that the impingement impact of J.R.Whiting before installation of a deterrent net to reduce impingement is 21.4 million age 1 equivalent fish and over 844,000 pounds of lost fishery yield per year. The entrainment impact is 1.8 million age 1 equivalent fish and 70,000 pounds of lost fishery yield per year. After installation of the deterrent net in 1981, average annual impingement loss at J.R. Whiting was 1.6 million age 1 equivalent fish per year. No entrainment data was available for this time period.

EPA examined the estimated economic value of I&E at J.R. Whiting before installation of the deterrent net to estimate the historical losses of the plant and potential I&E damages at other Great Lakes facilities that do not employ technologies to reduce impingement or entrainment. Average impingement without the net is valued at between $0.4 million and $1.2 million per year, and average entrainment is valued at between $42,000 and $1.7 million per year (all in $2001) (see Table: C2-8).

The midpoints of the pre-net results from the benefits transfer approach were used as the lower ends of the valuations losses. The upper ends of the valuation of losses reflect results of the HRC method for valuing I&E losses. EPA included the HRC-based estimates of the economic value of I&E losses at J.R. Whiting with the transfer-based estimates to provide a better estimate of loss values, particularly for forage species for which valuation techniques are limited.

Table C2-8: Baseline Impacts (annual average) in the Great Lakes (One In-Scope Facility: J.R. Whiting Without Net)

Baseline Impacts	Impingement	Entrainment
Age 1 equivalent fish lost	>21.4million/yr	> 1.8 million/yr
# lbs lost to landed fishery	> 844,300 lb/yr	> 70,000lb/yr
$ value of loss ($2001)	$0.4 million - $1.2 million/yr	$42,000 - $1.7 million/yr

Source: U.S. EPA analysis, 2002.

Impingement losses at J.R. Whiting with an aquatic barrier net are estimated to be reduced by 92 percent , while entrainment losses are not significantly affected. Thus, losses with a net are valued at between $29,000 and $99,000 for impingement and between $42,000 and $1.7 million per year for entrainment (all in $2001) (see Table C2-9).

Table C2-9: Baseline Impacts (annual average) in the Great Lakes (One In-Scope Facility: J.R. Whiting With Net)

Baseline Impacts	Impingement	Entrainment
Age 1 equivalent fish lost	> 1.6million/yr	n/a
# lbs lost to landed fishery	> 62,700 lb/yr	n/a
$ value of loss ($2001)	$29,000 - $99,000/yr	n/a

Source: U.S. EPA analysis, 2002.

C2-8 Large River Tributary to the Great Lakes

EPA estimates that the baseline impingement losses at the Monroe facility are 35.8 million age 1 equivalents and 1.4 million pounds of lost fishery yield per year. Baseline entrainment impacts amount to 11.6 million age 1 equivalents and 608,300 pounds of lost fishery yield each year.

The results of EPA's evaluation of the dollar value of baseline I&E losses at Monroe (as calculated using benefits transfer) indicate that baseline economic losses range from $502,200 to $981,750 per year for impingement and from $314,600 to $2,298,500 per year for entrainment (all in $2001).

EPA also developed an HRC analysis to examine the costs of restoring I&E losses at Monroe. These HRC estimates were merged with the benefits transfer results to develop a more comprehensive range of loss estimates. The HRC results were used as an upper bound and the midpoint of the benefits transfer method was used as a lower bound (HRC annualized at 7 percent over 20 years). Combining both approaches, the value of I&E losses at Monroe range from approximately $0.7 million to $5.6 million per year for impingement, and from $1.3 million to $13.9 million per year for entrainment (all in $2001) (see Table C2-10).

For a variety of reasons, EPA believes that the estimates developed here underestimate the total economic benefits of reducing I&E at the Monroe facility. EPA assumed that the effects of I&E on fish populations are constant over time (i.e., that fish kills do not have cumulatively greater impacts on diminished fish populations). EPA also did not analyze whether the number of fish affected by I&E would increase as populations increase in response to improved water quality or other improvements in environmental conditions. In the economic analyses, EPA also assumed that fishing is the only recreational activity affected.

Table C2-10: Baseline Losses at (annual average) in a Large River Tributary to the Great Lakes (One In-Scope Facility: Monroe using HRC)

Baseline Losses	Impingement	Entrainment
Age 1 equivalent fish lost	> 35.8 million/yr	> 11.6 million/yr
# lbs lost to landed fishery	> 1.4 million lb/yr	> 608,300lb/yr
$ value of loss ($2001)	$0.7 million - $5.6 million	$1.3 million - $13.9 million

Source: U.S. EPA analysis, 2002.

C2-9 National Baseline Losses Due to Impingement and Entrainment at In-Scope Facilities

Using the case study results reported above, EPA calculated the average number of age 1 equivalent fish lost per million gallons of daily average flow at several representative case study sites (one for each waterbody type). EPA then multiplied these average loss values by the estimated total average daily flow at all in-scope facilities in each waterbody category[2]. The result is an estimate of the total number of baseline losses of fish impinged and entrained in cooling water intake structures at in-scope facilities.

[2] To estimate the total average daily flow by waterbody type, EPA applied sample weights based on the sampling design for the 316(b) questionnaires to the reported average daily flows and summed the weighted flows by category to obtain an estimated of total average daily flow at all 550 in-scope facilities, by waterbody type.

The results of this analysis indicate that over 1.1 billion age 1 equivalent fish are lost annually as a results of I&E at the 550 in-scope facilities. Results by waterbody type are presented in Table C2-11. The national economic value of these losses is discussed in *Chapter C3: National Extrapolation of Baseline Losses* of this EBA.

Table C2-11: Estimated Impingement and Entrainment Losses at In-Scope Facilities (values in millions of age 1 equivalents)

Waterbody Type	Facility Used to Extrapolate	Impingement			Entrainment		
		Fishery Species	Forage Species	Total	Fishery Species	Forage Species	Total
Estuary/Tidal River-North Atlantic[a]	Salem (Delaware)	84.69	137.49	222.18	1,418.81	7,080.16	8,498.97
Estuary/Tidal River-South Atlantic/Gulf	Big Bend (Tampa Bay)	4.57	0.80	5.37	134.41	98,593.63	98,728.04
Freshwater Systems	9 Ohio Facilities (Ohio)	3.53	114.93	118.46	40.85	277.73	318.58
Great Lake	JR Whiting (Great Lakes)	528.64	19.58	548.22	43.06	3.67	46.72
Ocean	Pilgrim (Seabrook and Pilgrim)	1.55	0.05	1.60	78.56	356.66	435.22
Total		**622.98**	**272.85**	**895.83**	**1,715.68**	**106,311.85**	**108,027.53**

[a] Based on I&E losses at Salem assuming 100% through-plant mortality. See *Chapter B3: Ecological Risk Assessment* in *Part B:The Delaware Estuary* of the *Watershed Case Study Analysis for the Proposed Section 316(b) Phase II Existing Facilities Rule* for a detailed analysis of I&E losses.

Source: U.S. EPA analysis, 2002.

Chapter C3: National Extrapolation of Baseline Losses

INTRODUCTION

In this chapter the case study results detailed in *Chapter C2: Summary of Case Study Results* are used to develop EPA's estimates of baseline losses from impingement and entrainment (I&E) at in-scope facilities nationwide. The case study losses are extrapolated to national losses, by waterbody type, using two methods. The first method uses data on average daily flow to capture the stress level the facility places on the environment. The second method uses data on angling activity near the facility to capture the level of demand for the fishery. A combination of these national loss estimates is then used to develop EPA's best estimates of baseline losses by waterbody type.

CHAPTER CONTENTS

C3-1 EXTRAPOLATION

To compare benefits to costs for a national rulemaking such as the 316b Phase II existing facility rule, national estimates of both costs and benefits must be determined. This chapter describes the methods EPA used to estimate national baseline losses due to I&E. These baseline losses are then used to estimate national benefits in *Chapter C4: Benefits*.

Baseline losses are very site-specific. This limited EPA's options for developing national-level baseline loss estimates from a diverse set of 550 in-scope entities. Time, resources, and data limited the number of case studies that could be performed for proposal, so to interpret these cases in a national context, the Agency identified a range of settings that reflect the likely losses at a given type of facility (and its key stressor-related attributes) in combination with the characteristics of the waterbody (receptor attributes) in which it is located. Losses can thus be defined by the various possible combinations of stressor (facility) and receptor (waterbody, etc.) combinations.

Ideally, case studies would be selected to represent each of these "loss potential" settings and then could be used to extrapolate to facilities with similar cooling water intake structures. However, data limitations and other considerations precluded EPA from developing enough case studies to reflect all loss potential settings. Data limitations also made it difficult to assign facilities to the various loss potential categories.

Based on the difficulties noted above, EPA adopted a more practical, streamlined extrapolation version of its preferred approach, since this is the only feasible approach available to the Agency. To develop a feasible, tractable manner for developing national baseline loss estimates from a small number of case study investigations, EPA made its national extrapolations on the basis of a combination of three relevant variables:

- the volume of water (operational flow) drawn by a facility;
- the level of recreational angling activity within the vicinity of the facility; and
- the type of waterbody on which the facility is located. Extrapolations were then made across facilities according to their respective waterbody type.

The first of these variables – operational flow (measured as millions of gallons per day, or MGD) – reflects the degree of stress caused by a facility. The second variable – the number of angler days in the area (measured as the number of

recreational angling days within a 120 mile radius) – reflects the degree to which there is a demand (value) by local residents to use the fishery that is impacted. The third variable – waterbody type (e.g., estuary, ocean, freshwater river or lake, or Great Lakes) – reflects the types, numbers, and lifestages of fish and other biological receptors that are impacted by the facilities. Accordingly, the extrapolations based on these three variables reflect the key factors that affect losses: the relevant stressor, the biological receptors, and the human demands for the natural resources and services impacted.

C3-1.1 Consideration of Volume of Water (Flow)

The flow variable the Agency developed for each facility is the flow at the facility (in MGD) divided by the total flow for all facilities located on the same type of waterbody. Thus, this flow index is the facility's percentage share of the total flow at all facilities in its waterbody type. Since this flow index has a value between 0 and 1, dividing the baseline loss at a case study site by the flow index yields an estimate of the total baseline loss at all facilities drawing cooling from the same type of waterbody.

The MGD levels used to calculate the flow index are based on average operational flows as reported by the facilities in the EPA 316(b) Detailed Questionnaire and Short Technical Questionnaire responses, or through publically available data.

C3-1.2 Consideration of Level of Recreational Angling

The angler day variable the Agency used is an index based on results from the U.S. Fish and Wildlife Survey as part of its *1996 National Survey of Fishing, Hunting, and Wildlife-Associated Recreation* (U.S. DOI, 1997). These data were interpreted within a GIS-based approach to estimate the level of recreational angling pursued by populations living within 120 miles of each facility.

In developing the index, EPA used a GIS analysis to identify counties where any portion of the county is within a 120-mile radius of each facility. EPA then defined the area for each facility to include the county the facility is located in and any other county with at least 50 percent of its population residing within 120 miles of the facility. In total, EPA identified 2,757 counties that were within the 120-mile radius of at least one in-scope facility.

Using estimates of angling activity by state, EPA then estimated angling activity levels for each county within the 120-mile area. The type of angling days estimated for each county are based on the angling categories defined in the 1996 survey and the type of waterbody where the facility's cooling water intake structures are located. For facilities located on freshwater streams, rivers, and lakes (not including the Great Lakes), EPA estimated the total number of freshwater angling days. For facilities located on an ocean, estuary, or tidal river EPA estimated the total number of saltwater angling days. For facilities located on one of the Great Lakes, EPA estimated the total number of Great Lakes angling days.

EPA then summed angling days across all counties in a facility's area to yield estimated angling days in the area near the facility. For each type of angling, EPA estimated angling days by county residents as a percentage of the state angling days by residents 16 years and older reported in the 1996 survey. Angling days in each state were partitioned into days by urban anglers and days by rural anglers based on the national percentages reported in the 1996 survey.[1] EPA then used these state urban and rural angling days to estimate the number of angling days in each county within the 120-mile radius of an in-scope facility.

EPA used the following formula to calculate angling days for urban counties within a 120-mile radius of each in-scope facility:

$$\textit{Urban County Angling Days} = \textit{State Urban Angling Days} \times \frac{\textit{Urban County Population Within } 120 \textit{ Mile Radius}}{\textit{State Urban Population}}$$

EPA used a similar formula to the one above for calculating rural county angling days within a 120-mile radius of each in-scope facility.

[1] For example, the 1996 national survey found that 58.8% of anglers in the U.S. came from urban areas. So for each state, EPA assigned 58.8% of the total freshwater angling days reported in the survey to the state's urban angling days and 41.2% to the state's rural angling days. Similar calculations were performed for saltwater angling and Great Lakes angling.

EPA determined urban and rural population by state by summing the 1999 county populations for the state's urban and rural counties respectively. EPA determined each county's urban/rural status using definitions developed by the U.S. Department of Agriculture (U.S. DOI, 1997).

Once total angling days were estimated, EPA calculated an angling index value for each facility. Like the flow index, the angling index is a measure of the facility's percentage share of the total angling days estimated at all in-scope facilities located on a similar waterbody. This index value provides an indication of the relative level of angling activity at each facility compared to other in-scope facilities on the same type of waterbody. Since angling index also has a value between 0 and 1, dividing the baseline loss at a case study site by the angling index yields a second estimate of the total baseline loss at all facilities drawing cooling from the same type of waterbody.

C3-1.3 Consideration of Waterbody Type

a. Estuaries

National baseline losses for estuaries are based on the Salem and Tampa Bay case studies. The case study results are extrapolated to other facilities on the basis of regional fishery types, to reflect the different types of fisheries that are impacted in various regions of the country's coastal waters. EPA used the estimated baseline losses from the four Tampa Bay facilities to extrapolate losses to all in-scope estuarine facilities in Gulf Coast states that were not included in the Tampa Bay case study. Likewise, the estimated baseline losses at the Salem facility were used to extrapolate to all in-scope estuarine facilities in states that are not on the Gulf Coast and that were not included in the Salem, Brayton Point, Contra Costa, or Pitsburgh case studies (note that the Salem results used for the extrapolation differ from the case study results presented above in order to reflect losses without a screen currently in place at the facility). Ideally, a West Coast facility would have served as the basis of extrapolation to estuarine facilities along the Pacific Coast, but EPA could not develop a suitable case study for that purpose in time for this proposal. EPA intends to develop such a western estuary case study and report its findings in an anticipated forthcoming Notice of Data Availability.

b. Rivers and Lakes

EPA combined rivers, lakes, and reservoirs into one class of freshwater-based facilities (the Great Lakes were considered separately and are not included in this group). The waterbody classifications for freshwater streams/rivers and lakes/reservoirs were grouped together for the extrapolation because of the similar ecological and hydrological characteristics of freshwater systems used as cooling water. The majority of these hydrologic systems have undergone some degree of modification for purposes such as water storage, flood control, and navigation. The degree of modification can range from very minor to quite dramatic. A facility in the lake/reservoir category may withdraw cooling water from a lake that has been reclassified as a reservoir due to the addition of an earthen dam, or from a reservoir created by the diversion of a river through a diversion canal for use as a cooling lake. The species composition and ecology of these two waterbodies may vary greatly. While the ecology of river systems and lakes or reservoirs is considerably different, structural modifications can make these two classifications may be quite similar ecologically, depending on the waterbody in question. For example, many river systems, including the Ohio River, are now broken up into a series of navigational pools controlled by dams that may function more like a reservoir than a naturally flowing river.

Baseline I&E losses in the Ohio case study were based on 29 in-scope facilities in the Ohio River case study area. In the results presented below, EPA used the estimated losses at these 29 facilities to extrapolate to an estimate of national losses at all in-scope facilities on other freshwater rivers, lakes, and reservoirs that were not included in the Ohio or Monroe case studies. The extrapolations were performed using both the flow and angling indices.

Because of the large number of facilities in the Ohio study and their proximity to each other, EPA used a slightly different method to estimate angling activity at these facilities. Rather than calculating the angling days within the 120-mile radius of each individual facility, EPA instead summed the angling days in all counties within 120 miles of any of the 29 Ohio facilities and divided this by the number of angling near any freshwater facility nationwide. Essentially, this method treats the 29 Ohio facilities as one large facility for the purposes of calculating an angling index. This eliminates the problem of multiple-counting of angling days in counties that occurs because the Ohio facilities are so close to each other.

c. Oceans and Great Lakes

Oceans and Great Lakes estimates were based on extrapolations from the Pilgrim and J.R. Whiting facility case studies, respectively. For these two facilities (and their associated waterbody types), the valuation method applied by EPA in the national extrapolations was based on the Habitat-based Replacement Cost (HRC) approach, which reflects values for addressing a much greater number of impacted species (not just the small share that are recreational or commercial species that are landed by anglers). For example, at JR Whiting, the benefits transfer approach developed values for recreational

angling amounted to only 4% of the estimated total impingement losses, and reflected only 0.02 % of the age 1 fish lost due to impingement. At Pilgrim, the benefits transfer approach reflected recreational losses for only 0.5 % of the entrained age 1 equivalent fish at that site. Because the Agency was able to develop HRC values for these sites and recreational fishery impacts were such a small part of the impacts, EPA extrapolated only based on HRC estimates and used only the flow-based (MGD) index for oceans and the Great Lakes.

In the results presented below, EPA used the estimated baseline losses from the Pilgrim facility to extrapolate losses to all in-scope ocean facilities with the exception of Seabrook, which has an off-shore intake and represents itself. Likewise, the estimated baseline losses at the J.R. Whiting facility were used to extrapolate to all in-scope Great Lakes facilities that were not included in the J.R. Whiting case study with the exception of the Monroe facility, which represents itself. The extrapolations were performed using both the flow and angling indices.

C3-1.4 Flow and Angling Indices

The results of the index calculations for operational flow and angling effort used for extrapolating case study baseline losses to national baseline losses for all in-scope facilities are reported in Table C3-1.

Table C3-1: Flow and Angling Indices

Waterbody Type	Based on	Normalized MGD	Percentage of In-Scope Angling Base
Estuary-N. Atlantic	Salem (without screens)	4.39%	2.10%
Estuary-S. Atlantic	4 Tampa Bay facilities	19.24%	20.28%
Freshwater systems	29 Ohio River facilities	9.30%	12.34%
Great Lake	JR Whiting	3.92%	13.89%
Ocean	Pilgrim	3.42%	6.54%

Source: U.S. EPA analysis, 2002.

C3-1.5 Waterbody Considerations

EPA further tailored its extrapolation approach to base monetized baseline loss (and benefits) estimates on available data for similar types of waterbody settings. Thus, for example, the case study results for the Salem facility (located in the Delaware Estuary) and the Tampa facilities are applied (on a per MGD and angling day index basis) only to other facilities located in estuary waters. Likewise, results from Ohio River facilities are applied to inland freshwater water cooling water intake structures (excluding facilities on the Great Lakes), and losses estimated for the Pilgrim plant are applied to facilities using ocean waters at their intakes, and results for J.R. Whiting are used for the Great Lakes facilities.

As noted above, EPA grouped the waterbody classifications for freshwater rivers and lakes/reservoirs for the extrapolation based on similar ecological and hydrological characteristics of freshwater systems used as cooling water. The majority of these hydrologic systems have undergone some degree of modification for purposes such as water storage, flood control, and navigation. Structural modifications can make these freshwater waterbody types quite similar ecologically. For example, many river systems, including the Ohio River, are now broken up into a series of navigational pools controlled by dams that may function more similarly to a reservoir than a naturally flowing river.

The natural species distribution, genetic movement, and seasonal migration of aquatic organisms that may be expected in a natural system is affected by factors such as dams, stocking of fish, and water diversions. Since the degree of modification of inland waterbodies and the occurrence of fish stocking could not be determined for every cooling water source, EPA grouped the waterbody categories “freshwater rivers” and “lakes/reservoirs” were grouped together.

The facilities chosen for extrapolation are expected to have relatively average losses per MGD and angling day index, for their respective waterbody types. Losses per MGD and angling day index are not expected to be extremely high or low

relative to other facilities. EPA was careful not use facilities that were unusual in this regard. Salem is located in the transitional zone of the estuary, a lesser productive part of the estuary.

C3-1.6 Advantages and Disadvantages of EPA's Extrapolation Approach

The use of flow and angler day basis for extrapolation has some practical advantages and basis in logic; however, it also has some less than fully satisfactory implications. The advantages of using this extrapolation approach include:

- The methods are easily implemented because the extrapolation relies on waterbody type, angler demand, and MGD data that are available or easily estimated for all in-scope facilities.
- Selectively extrapolating case study results to facilities on like types of waterbodies reflects the type of aquatic setting impacted, which is intended to capture the number and types of species impacted by I&E at such facilities (i.e., impacts at facilities on estuaries are more similar to impacts at other estuary-based cooling water intake structures than they are to facilities on inland waters).
- Flow in MGD is a useful proxy for the scale of operation at cooling water intake structures, a variable that typically will have a large impact on baseline losses and potential regulatory benefits.
- While there may be a high degree of variability in the actual losses (and benefits) per MGD across facilities that impact similar water bodies, the extrapolations are expected to be reasonably accurate on average for developing an order-of-magnitude national-level estimate of benefits. There is no systematic upward or downward bias to these estimates.
- The recreational participation level (angler days) variable provides a logical basis to reflect the extent of human user demands for the fishery and other resources affected by I&E.
- The national benefit estimates are not biased in either direction.

Some of the disadvantages of the use of extrapolating results on the basis of waterbody type, recreational angling day data, and operational flows (MGD) include:

- The approach may not reflect all of the variability that exists in I&E impacts (and monetized losses or benefits) within waterbody classifications. For example, within and across U.S. estuaries, there may be different species, numbers of individuals, and life stages present at different cooling water intake structures.
- The approach may not reflect all of the variability that exists in I&E impacts (and monetized losses or benefits) across operational flow levels (MGD) at different facilities within a given waterbody type.

Extrapolating to national baseline losses according to flow (MGD), angling levels, and waterbody type, as derived from estimates for a small number of case studies, may introduce inaccuracies into national estimates. This is because the three variables used as the basis for the extrapolation (MGD, recreational angling days, and waterbody type) may not account for all of the variability expected in site-specific benefits levels. The case studies may not reflect the average or "typical" cooling water intake structures impacts on a specific waterbody (i.e., the extrapolated results might under- or overstate the physical and dollar value of impacts per MGD and fishing day index, by waterbody type for a specific facility). The inaccuracies introduced to the national-level estimates by this extrapolation approach are of unknown magnitude or direction (i.e., the estimates may over- or understate the anticipated national-level benefits); however, EPA has no data to indicate that the case study results are atypical for any of the waterbody types analyzed or that they are in any way biased.

C3-2 Results of National Benefits Extrapolation

EPA developed estimates of national benefits attributable to the proposed rule in two main stages. In the first stage, national baseline losses were estimated. The methods used for this analysis are detailed above and the results are presented below. In the second, EPA applied the expected reductions under several regulatory options to the national baseline loss estimates to calculated expected benefits of the rule. EPA's benefits estimates are presented in *Chapter C4: Benefits*.

C3-2.1 Case Study Baseline Losses

In the first step of the baseline loss extrapolation, EPA used the baseline losses (dollars per year) derived from the analysis of facilities examined in the case studies. In some instances, the case study facilities had already implemented some measures to reduce impingement and/or entrainment. In such cases, baseline losses as appropriate to the national extrapolation were estimated using data for years prior to the facilities' actions (e.g., based on I&E before the impingement deterrent net was installed at J.R. Whiting). These pre-action baselines provide a basis for examining other facilities that have not yet taken

actions to reduce impingement and/or entrainment. Baseline losses at the selected case study facilities are summarized in Table C3-2.

Table C3-2: Baseline Losses from Selected Case Studies (in thousands, $2001)

Case Study	Impingement			Entrainment		
	Low	Mid	High	Low	Mid	High
Salem	$528	$704	$879	$16,766	$23,657	$30,548
Brayton Point	$9	$450	$890	$235	$14,261	$28,288
Contra Costa	$2,666	$5,726	$8,785	$6,413	$13,630	$20,847
Pittsburgh	$10,096	$22,268	$34,440	$19,166	$40,760	$62,354
4 Tampa Bay Facilities	$801	$809	$817	$20,007	$20,454	$20,901
29 Ohio Facilities	$3,452	$4,052	$4,652	$9,257	$9,584	$9,912
Monroe	$742	$3,190	$5,639	$1,307	$7,604	$13,902
JR Whiting	$358	$797	$1,235	$42	$873	$1,703
Pilgrim Nuclear	$4	$256	$507	$642	$4,960	$9,279
Seabrook Nuclear	$3	$4	$5	$142	$229	$315

Source: U.S. EPA analysis, 2002.

C3-2.2 Extrapolation of Baseline Losses to All Facilities Using Flow Index

In the second step, EPA extrapolated the baseline dollar loss estimates from the case study models to all 539 facilities that responded to the Agency's facility survey by dividing the estimated dollar losses at baseline per unit flow by the sum of the index of operational flow for each non-case study facility. This extrapolation was done by source waterbody type. This resulted in a national estimate of baseline monetizable losses for all 539 responding facilities as summarized in Table C3-3.[2]

Table C3-3: Baseline Losses Extrapolated to All In-Scope Facilities Using MGD Only[a] (in thousands, $2001)

Facility	Case Study	Impingement			Entrainment		
		Low	Mid	High	Low	Mid	High
Estuary - Non Gulf							
Salem	Delaware	$528	$704	$879	$16,766	$23,657	$30,548
Brayton Point	Brayton	$9	$450	$890	$235	$14,261	$28,288
Contra Costa	California	$2,666	$5,726	$8,785	$6,413	$13,630	$20,847
Pittsburgh	California	$10,096	$22,268	$34,440	$19,166	$40,760	$62,354
All Other In-Scope	---	$11,167	$14,875	$18,583	$354,346	$499,991	$645,636
Total (78 In-Scope Facilities)	---	*$24,467*	*$44,022*	*$63,578*	*$396,925*	*$592,298*	*$787,672*
Estuary - Gulf Coast							
4 Tampa Facilities	Tampa Bay	$801	$809	$817	$20,007	$20,454	$20,901
All Other In-Scope	---	$3,361	$3,395	$3,429	$83,982	$85,857	$87,732
Total (30 In-Scope Facilities)	---	*$4,162*	*$4,204*	*$4,247*	*$103,989*	*$106,311*	*$108,633*
Freshwater							
29 Ohio Facilities	Ohio	$3,452	$4,052	$4,652	$9,257	$9,584	$9,912
Monroe	Monroe	$742	$3,190	$5,639	$1,307	$7,604	$13,902
All Other In-Scope	---	$33,317	$39,111	$44,906	$89,348	$92,514	$95,679
Total (393 In-Scope Facilities)	---	*$37,511*	*$46,353*	*$55,196*	*$99,911*	*$109,702*	*$119,493*
Great Lake							
JR Whiting	JR Whiting	$358	$797	$1,235	$42	$873	$1,703
All Other In-Scope	---	$8,774	$19,523	$30,271	$1,025	$21,385	$41,745
Total (16 In-Scope Facilities)	---	*$9,132*	*$20,319*	*$31,506*	*$1,067*	*$22,257*	*$43,448*
Ocean							
Pilgrim Nuclear	Pilgrim	$4	$256	$507	$642	$4,960	$9,279
Seabrook Nuclear	Seabrook	$3	$4	$5	$142	$229	$315
All Other In-Scope	---	$110	$6,886	$13,662	$17,290	$133,676	$250,062
Total (22 In-Scope Facilities)	---	*$118*	*$7,146*	*$14,174*	*$18,074*	*$138,865*	*$259,656*
All In-Scope Facilities							
Total (539 In-Scope Facilities)	---	**$75,388**	**$122,045**	**$168,701**	**$619,966**	**$969,434**	**$1,318,902**

[a] Baseline losses are estimated based on survey data from 539 in-scope facilities and include baseline closures.

Source: U.S. EPA analysis, 2002.

[2] Data from the 316(b) questionnaire were available for 539 of the estimated 550 in-scope facilities. EPA presents sample-weighted benefits estimates in Chapter C4 that reflect baseline losses and benefits at all 550 in-scope facilities. Un-weighted benefits estimates are presented in Appendix C1.

C3-2.3 Extrapolation of Baseline Losses to All Facilities Using Angling Index

In the third step, the Agency extrapolated the baseline dollar loss estimates from the case studies to all in-scope facilities in the database by dividing baseline losses from the case study models by the sum of the angling index values for all non-case study facilities. This was done by source waterbody type. The calculation of the index is described above. The results are summarized in Table C3-4.

Table C3-4: Baseline Losses Extrapolated - Angling Days Only[a] (in thousands, $2001)

Facility	Case Study	Impingement			Entrainment		
		Low	Mid	High	Low	Mid	High
Estuary - Non Gulf							
Salem	Delaware	$528	$704	$879	$16,766	$23,657	$30,548
Brayton Point	Brayton	$9	$450	$890	$235	$14,261	$28,288
Contra Costa	California	$2,666	$5,726	$8,785	$6,413	$13,630	$20,847
Pittsburgh	California	$10,096	$22,268	$34,440	$19,166	$40,760	$62,354
All Other In-Scope	---	$23,840	$31,755	$39,671	$756,471	$1,067,399	$1,378,327
Total (78 In-Scope Facilities)	---	*$37,139*	*$60,903*	*$84,667*	*$799,050*	*$1,159,706*	*$1,520,363*
Estuary - Gulf Coast							
4 Tampa Facilities	Tampa Bay	$801	$809	$817	$20,007	$20,454	$20,901
All Other In-Scope	---	$3,148	$3,180	$3,212	$78,664	$80,421	$82,177
Total (30 In-Scope Facilities)	---	*$3,949*	*$3,989*	*$4,029*	*$98,672*	*$100,875*	*$103,078*
Freshwater							
29 Ohio Facilities	Ohio	$3,452	$4,052	$4,652	$9,257	$9,584	$9,912
Monroe	Monroe	$742	$3,190	$5,639	$1,307	$7,604	$13,902
All Other In-Scope	---	$23,203	$27,238	$31,273	$62,224	$64,429	$66,633
Total (393 In-Scope Facilities)	---	*$27,396*	*$34,480*	*$41,564*	*$72,787*	*$81,617*	*$90,447*
Great Lake							
JR Whiting	JR Whiting	$358	$797	$1,235	$42	$873	$1,703
All Other In-Scope	---	$2,220	$4,940	$7,660	$259	$5,411	$10,564
Total (16 In-Scope Facilities)	---	*$2,578*	*$5,737*	*$8,895*	*$301*	*$6,284*	*$12,267*
Ocean							
Pilgrim Nuclear	Pilgrim	$4	$256	$507	$642	$4,960	$9,279
Seabrook Nuclear	Seabrook	$3	$4	$5	$142	$229	$315
All Other In-Scope	---	$54	$3,402	$6,750	$8,543	$66,047	$123,551
Total (22 In-Scope Facilities)	---	*$62*	*$3,662*	*$7,262*	*$9,326*	*$71,236*	*$133,145*
All In-Scope Facilities							
Total (539 In-Scope Facilities)	---	**$71,125**	**$108,771**	**$146,418**	**$980,137**	**$1,419,718**	**$1,859,300**

[a] Baseline losses are estimated based on survey data from 539 in-scope facilities and include baseline closures.

Source: U.S. EPA analysis, 2002.

C3-2.4 Average of Flow-Based and Angling-Based Losses

As a fourth step, EPA calculated the average baseline losses of the flow-based results and the angling-based results. This develops results that reflect an equally-weighted extrapolation measure of each case study facility's baseline loss, based on it's percent share of flow and recreational fishing relative to all in-scope facilities in each waterbody type. The results of this average are reported in Table C3-5.

Table C3-5: Baseline Losses Extrapolated to All In-Scope Facilities - Means of MGD and Angling[a] (in thousands, $2001)

Facility	Case Study	Impingement			Entrainment		
		Low	Mid	High	Low	Mid	High
Estuary - Non Gulf							
Salem	Delaware	$528	$704	$879	$16,766	$23,657	$30,548
Brayton Point	Brayton	$9	$450	$890	$235	$14,261	$28,288
Contra Costa	California	$2,666	$5,726	$8,785	$6,413	$13,630	$20,847
Pittsburgh	California	$10,096	$22,268	$34,440	$19,166	$40,760	$62,354
All Other In-Scope	---	$17,503	$23,315	$29,127	$555,409	$783,695	$1,011,981
Total (78 In-Scope Facilities)	---	*$30,803*	*$52,463*	*$74,122*	*$597,988*	*$876,002*	*$1,154,017*
Estuary - Gulf Coast							
4 Tampa Facilities	Tampa Bay	$801	$809	$817	$20,007	$20,454	$20,901
All Other In-Scope	---	$3,255	$3,288	$3,321	$81,323	$83,139	$84,955
Total (30 In-Scope Facilities)	---	*$4,055*	*$4,097*	*$4,138*	*$101,330*	*$103,593*	*$105,856*
Freshwater							
29 Ohio Facilities	Ohio	$3,452	$4,052	$4,652	$9,257	$9,584	$9,912
Monroe	Monroe	$742	$3,190	$5,639	$1,307	$7,604	$13,902
All Other In-Scope	---	$28,260	$33,175	$38,089	$75,786	$78,471	$81,156
Total (393 In-Scope Facilities)	---	*$32,453*	*$40,417*	*$48,380*	*$86,349*	*$95,660*	*$104,970*
Great Lake							
JR Whiting	JR Whiting	$358	$797	$1,235	$42	$873	$1,703
All Other In-Scope	---	$5,497	$12,231	$18,966	$642	$13,398	$26,154
Total (16 In-Scope Facilities)	---	*$5,855*	*$13,028*	*$20,201*	*$684*	*$14,271*	*$27,858*
Ocean							
Pilgrim Nuclear	Pilgrim	$4	$256	$507	$642	$4,960	$9,279
Seabrook Nuclear	Seabrook	$3	$4	$5	$142	$229	$315
All Other In-Scope	---	$82	$5,144	$10,206	$12,916	$99,861	$186,806
Total (22 In-Scope Facilities)	---	*$90*	*$5,404*	*$10,718*	*$13,700*	*$105,050*	*$196,401*
All In-Scope Facilities							
Total (539 In-Scope Facilities)	---	**$73,257**	**$115,408**	**$157,559**	**$800,051**	**$1,194,576**	**$1,589,101**

[a] Baseline losses are estimated based on survey data from 539 in-scope facilities and include baseline closures.

Source: U.S. EPA analysis, 2002.

C3-2.5 Best Estimates

In the fifth step, EPA selected the set of extrapolation values the Agency believes are the most reflective of the baseline loss scenarios for each waterbody type. For estuaries and freshwater facilities, EPA used the midpoint of its loss estimates of I&E at the case study facilities, and then applied the average of the MGD- and angler-based extrapolation results. This provides estimates of national baseline losses that reflect the broadest set of values and parameters (i.e., the full range of loss estimates, plus the application of all three extrapolation variables).

For oceans and the Great Lakes, EPA developed national-scale estimates using its HRC-based loss estimates. These HRC estimates are most appropriate because these HRC values are more comprehensive than the values derived using the more traditional benefits transfer approach. The HRC estimates cover losses for a much larger percentage of fish lost due to I&E, whereas the benefits transfer approach addressed losses only for a small share of the impacted fish. Since recreational fish impacts were an extremely small share of the total fish impacts at these sites, EPA extrapolated the HRC findings using only the MGD-based index (i.e., the angler-based index was not relevant).

The results of EPA's assessment of its best estimates for baseline losses due to I&E are shown in Table C3-6.

Table C3-6: Best Estimate Baseline Losses[a, b] (in thousands, $2001)

Facility	Case Study	Impingement	Entrainment
Estuary - Non Gulf			
Salem	Delaware	$704	$23,657
Brayton Point	Brayton	$450	$14,261
Contra Costa	California	$5,726	$13,630
Pittsburgh	California	$22,268	$40,760
All Other In-Scope	---	$23,315	$783,695
Total (78 In-Scope Facilities)	---	*$52,463*	*$876,002*
Estuary - Gulf Coast			
4 Tampa Facilities	Tampa Bay	$809	$20,454
All Other In-Scope	---	$3,288	$83,139
Total (30 In-Scope Facilities)	---	*$4,097*	*$103,593*
Freshwater			
29 Ohio Facilities	Ohio	$4,052	$9,584
Monroe	Monroe	$3,190	$7,604
All Other In-Scope	---	$30,891	$73,069
Total (393 In-Scope Facilities)	---	*$38,133*	*$90,258*
Great Lake			
JR Whiting	JR Whiting	$1,235	$1,703
All Other In-Scope	---	$30,271	$41,745
Total (16 In-Scope Facilities)	---	*$31,506*	*$43,448*
Ocean			
Pilgrim Nuclear	Pilgrim	$507	$9,279
Seabrook Nuclear	Seabrook	$5	$315
All Other In-Scope	---	$13,662	$250,062
Total (22 In-Scope Facilities)	---	*$14,174*	*$259,656*
All In-Scope Facilities			
Total (539 In-Scope Facilities)	**---**	**$142,656**	**$1,378,359**

[a] Baseline losses are estimated based on survey data from 539 in-scope facilities and include baseline closures.
[b] Facilities in bold, were used for extrapolation.

Source: U.S. EPA analysis, 2002.

REFERENCES

U.S. Department of the Interior (U.S. DOI), Fish and Wildlife Service, and U.S. Department of Commerce (U.S. DOC), Bureau of the Census. 1997. *1996 National Survey of Fishing, Hunting, and Wildlife-Associated Recreation.*

Chapter C4: Benefits

Introduction

Using the national baseline loss estimates reported in *Chapter C3: National Extrapolation of Baseline Losses*, EPA estimated the potential national benefits of each regulatory option by applying a set of estimated percent reductions to baseline losses. The estimates were developed using sample weights based on the sampling design for the 316(b) questionnaires. These weights were used to generate benefits estimates for all 550 in-scope facilities based on the baseline losses for 539 in-scope facilities for which questionnaire data was available. Estimates of benefits for only the 539 in-scope facilities can be found in the *Appendix to Chapter C1*.

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The percent reduction in baseline losses for each facility reflects EPA's assessment of (1) regulatory baseline conditions at the facility (i.e., current practices and technologies in place), and (2) the percent reductions in impingement and entrainment that EPA estimated would be achieved at each facility that the Agency believes would be adopted under each regulatory option.

C4-1 Options with Benefit Estimates

EPA estimated benefits for the following six options. These options include:

- **Option 1:** Track I of the waterbody /capacity-based option;
- **Option 2:** Track I and II of the waterbody /capacity-based option;
- **Option 3:** (the Agency's proposed rule), impingement and entrainment controls everywhere with exceptions for low-flow facilities on lakes and rivers;
- **Option 3a:** impingement and entrainment controls everywhere with no exceptions;
- **Option 4:** requires all Phase II existing facilities to reduce intake capacity commensurate with the use of closed-cycle, recirculating cooling systems; and
- **Option 5:** requires that all Phase II existing facilities reduce intake capacity commensurate with the use of dry cooling systems.
- **Option 6:** similar to Option1, but requires reduction commensurate with the use of closed-cycle, recirculating systems for all facilities on estuaries, tidal rivers, and oceans

A complete description of the options detailed in the following tables can be found in *Chapter A1: Introduction and Overview* of this Economic and Benefits Analysis (EBA). Benefits detailed in this chapter are the flow-weighted average reductions across all facilities in each water body category for each regulatory option.. See *Chapter C3: National Extrapolation of Baseline Losses* for a discussion on the methodology used to extrapolate benefits.

C4-2 Impingement Reductions and Benefits

Table C4-1 presents the percentage reductions in impingement that are expected to occur under the six options listed above and Table C4-2 presents the benefit value associated with those reductions.

Table C4-1: National Impingement Benefits for Various Options - By reduction Level

Waterbody Type	Baseline Impingement Loss	Percentage Reductions						
		Option 1	Option 2	Option 3	Option 3a	Option 4	Option 5	Option 6
Estuary - Non-Gulf	$57,802	64.4%	47.5%	33.2%	25.5%	41.4%	97.5%	84.4%
Estuary - Gulf	$4,098	63.2%	45.9%	27.1%	30.0%	45.3%	96.7%	79.4%
Freshwater	$40,813	47.2%	47.2%	47.2%	46.6%	58.9%	98.0%	47.7%
Great Lake	$31,506	80.0%	80.0%	80.0%	77.0%	88.6%	96.3%	80.0%
Ocean	$15,136	72.8%	59.0%	50.1%	46.5%	58.9%	87.6%	77.7%
Total	**$149,356**							

Source: U.S. EPA analysis, 2002.

Table C4-2: National Impingement Benefits for Various Options - By Benefit Level (in thousands, $2001)

Waterbody Type	Baseline Impingement Loss	Benefits						
		Option 1	Option 2	Option 3	Option 3a	Option 4	Option 5	Option 6
Estuary - Non-Gulf	$57,802	$37,233	$27,452	$19,193	$14,754	$23,924	$56,338	$48,777
Estuary - Gulf	$4,098	$2,590	$1,883	$1,109	$1,230	$1,857	$3,963	$3,254
Freshwater	$40,813	$19,282	$19,282	$19,282	$19,015	$24,041	$39,991	$19,471
Great Lake	$31,506	$25,205	$25,205	$25,205	$24,260	$27,900	$30,326	$25,205
Ocean	$15,136	$11,020	$8,923	$7,587	$7,034	$8,912	$13,265	$11,763
Total	**$149,356**	**$95,330**	**$82,744**	**$72,375**	**$66,294**	**$86,633**	**$143,883**	**$108,470**

Source: U.S. EPA analysis, 2002.

C4-3 Entrainment Reductions and Benefits

Table C4-3 presents the percentage reductions in impingement that are expected to occur under the six options listed above and Table C4-4 presents the benefit value associated with those reductions.

Table C4-3: National Entrainment Benefits for Various Options - By Reduction Level

Waterbody Type	Baseline Loss	Entrainment Percentage Reductions						
		Option 1	Option 2	Option 3	Option 3a	Option 4	Option 5	Option 6
Estuary - Non-Gulf	$936,275	67.3%	59.3%	48.5%	47.3%	79.4%	97.5%	$48,777
Estuary - Gulf	$103,635	66.9%	52.3%	47.2%	47.8%	79.3%	96.7%	$3,254
Freshwater	$96,597	12.4%	12.4%	12.4%	44.2%	72.8%	98.0%	$19,471
Great Lake	$43,448	57.8%	57.8%	57.8%	57.8%	88.6%	96.3%	$25,205
Ocean	$277,269	72.9%	57.8%	44.1%	44.1%	72.8%	87.6%	$11,763
Total	**$1,457,225**							**$108,470**

Source: U.S. EPA analysis, 2002.

Table C4-4: National Entrainment Benefits for Various Options By Benefit Level (in thousands, $2001)

Waterbody Type	Baseline Loss	Entrainment Benefit						
		Option 1	Option 2	Option 3	Option 3a	Option 4	Option 5	Option 6
Estuary - NonGulf	$936,275	$630,568	$555,238	$453,938	$443,239	$743,085	$912,568	$732,964
Estuary - Gulf	$103,635	$69,352	$54,229	$48,910	$49,529	$82,220	$100,216	$81,194
Freshwater	$96,597	$11,957	$11,957	$11,957	$42,737	$70,310	$94,652	$9,472
Great Lake	$43,448	$25,092	$25,092	$25,092	$25,092	$38,474	$41,820	$25,092
Ocean	$277,269	$202,116	$160,288	$122,351	$122,351	$201,983	$242,989	$201,983
Total	**$1,457,225**	**$939,085**	**$806,803**	**$662,248**	**$682,949**	**$1,136,073**	**$1,392,246**	**$1,050,705**

Source: U.S. EPA analysis, 2002.

C4-4 Certainty Levels Associated with Benefit Estimates of Various Options

Table C4-5 presents information detailing differences in levels of uncertainty associated with the different options.

Table C4-5: Certainty of Benefits Estimates Associated with the Various Options

Option		Characteristics / Assumptions	Certainty of Achieving Predicted Reductions and Benefits
Waterbody/ Capacity-Based Option (Allows two tracks)	**Option 1**	assumes everyone will use Track 1	Very certain for the 51 facilities assumed to install cooling towers. Expected percentage reductions are within a limited range Less certain for other facilities as technology is unknown
	Option 2	assumes that 20 sample facilities will use Track 2	Expected percentage reductions are within a limited range Less certain for other facilities as technology that would be chosen is unknown. Uncertainty due to assumptions about the number of facilities that may choose Track 2 instead of Track 1 Very certain for the 33 facilities assumed to install cooling towers.
Proposed Rule (Option 3)		impingement and entrainment controls everywhere with exceptions for low-flow facilities on lakes and rivers	Uncertain because the technologies chosen by facilities is unknown Number of facilities that would request alternative less stringent requirements based on costs is unknown. Number of facilities that would request alternative less stringent requirements based on benefits is unknown.
Impingement Mortality and Entrainment Controls Everywhere **(Option 3a)**		impingement and entrainment controls everywhere with no exceptions	Fairly certain, but the technologies chosen by facilities is unknown
All Cooling Towers (**Option 4)**		requires reduction commensurate with the use of closed-cycle, recirculating systems	Very certain for the 470 facilities installing wet cooling towers. Expected percentage reductions are within a limited range
Dry Cooling **(Option 5)**		requires reduction commensurate with the use of dry cooling systems	Extremely certain for the 539 facilities installing dry cooling
Waterbody-Based **(Option 6)**		Similar to Option1, but requires reduction commensurate with the use of closed-cycle, recirculating systems for all facilities on estuaries, tidal rivers, and oceans	Very certain for the 109 facilities assumed to install cooling towers. Expected percentage reductions are within a limited range Less certain for other facilities as technology is unknown

Source: U.S. EPA analysis, 2002.

C4-5 Benefits Associated with Various Percentage Reductions

In addition to percentage reductions by option, EPA developed a more generic illustration of potential benefits, based on a broad range (from 10 percent to 90 percent) of potential reductions in impingement and entrainment. These results are shown in Table C4-6.

Table C4-6: Summary of Potential Benefits Associated with Various Impingement and Entrainment Reduction Levels

Reduction Level	Benefits (in thousands, $2001)	
	Impingement	Entrainment
10%	$14,936	$145,722
20%	$29,871	$291,445
30%	$44,807	$437,167
40%	$59,742	$582,890
50%	$74,678	$728,612
60%	$89,613	$874,335
70%	$104,549	$1,020,057
80%	$119,484	$1,165,780
90%	$134,420	$1,311,502

Source: U.S. EPA analysis, 2002.

C4-6 Benefits Associated with the Proposed Option

Table C4-7 presents the benefits that would occur with various percentage reductions

Table C4-7: Summary of Benefits from Impingement Controls Associated with the Proposed Rule (Option 3)

Waterbody Type	Benefits (in thousands, $2001)	
	Impingement	Entrainment
Estuary - NonGulf	$19,193	$453,938
Estuary - Gulf	$1,109	$48,910
Freshwater	$19,282	$11,957
Great Lake	$25,205	$25,092
Ocean	$7,587	$122,351
Total	**$72,375**	**$662,248**

Source: U.S. EPA analysis, 2002.

Under today's proposal, facilities can choose the Site-Specific Determination of Best Technology Available in § 125.94(a) in which a facility can demonstrate to the Director that the cost of compliance with the applicable performance standards in § 125.94(b) would be significantly greater than the costs considered by EPA when establishing these performance standards, or the costs would be significantly greater than the benefits of complying with these performance standards. EPA expects that if facilities were to choose this approach, then the overall national benefits of this rule will decrease markedly. This is because under this approach facilities would choose the lowest cost technologies possible and not necessarily the most effective technologies to reduce impingement and entrainment at the facility.

The estimates that appear in this chapter are weighted estimates of benefits at all 550 in-scope facilities. The weights use are based on the sampling design for the 316(b) questionnaires. See the *Appendix to Chapter C1* for the benefit estimates on an unweighted basis.

Chapter D1: Comparison of National Costs and Benefits

INTRODUCTION

This chapter summarizes total private costs, develops social costs, and compares total social costs to total benefits at the national level for the proposed rule and five alternative regulatory options.

CHAPTER CONTENTS

Table D1-1 shows compliance response assumptions for the proposed rule and five alternative regulatory options based on each facility's current technologies installed, capacity utilization, waterbody type, annual intake flow, and design intake flow as a percent of source waterbody mean annual flow. *Chapter A1: Introduction and Overview* includes a more detailed discussion of compliance responses under the proposed rule and alternative regulatory options.

Table D1-1: Number of Facilities by Compliance Assumption and Regulatory Option (based on 539 sample facilities)

Facility Compliance Assumption	Waterbody/Capacity-Based Option (Allows two tracks)		Proposed Rule[a] (Option 3)	Impingement Mortality and Entrainment Controls Everywhere Option (Option 3a)	All Cooling Towers Option (Option 4)	Dry Cooling Option (Option 5)	Waterbody-Based Option (Option 6)
	Option 1	Option 2					
Cooling tower in baseline (no action)	69	69	69	69	69	69	69
Impingement Controls Only	241	241	241	53	53	241	241
Impingement and Entrainment Controls	178	198	229	417	0	178	120
Flow Reduction Technology	51	31	0	0	417	51	109

[a] Alternative less stringent requirements based on both costs and benefits are allowed. There is some uncertainty in predicting compliance responses because the number of facilities requesting alternative less stringent requirements based on costs and benefits is unknown.

Source: U.S. EPA analysis, 2002.

D1-1 Social Costs

This section develops EPA's estimates of the costs to society associated with the proposed rule. The ***social costs*** of regulatory actions are the ***opportunity costs*** to society of employing scarce resources in pollution prevention and pollution control activities. The compliance costs used to estimate total social costs differ in their consideration of taxes from those in *Part B: Costs and Economic Impacts*, which were calculated for the purpose of estimating the private costs and impacts of the rule. For the impact analyses, compliance costs are measured as they affect the financial performance of the regulated facilities and firms. The analyses therefore explicitly consider the tax deductibility of compliance expenditures.[1] In the analysis of costs to society, however, these compliance costs are considered on a pre-tax basis. The costs to society are the full value of the resources used, whether they are paid for by the regulated facilities or by all taxpayers in the form of lost tax revenues.

To assess the economic costs to society of the proposed regulation, EPA relied first on the estimated costs to facilities for the labor, equipment, material, and other economic resources needed to comply with the proposed rule. In this analysis, EPA assumes that the market prices for labor, equipment, material, and other compliance resources represent the opportunity costs to society for use of those resources in regulatory compliance. EPA also assumes that the lost revenue from energy penalties and construction outage – which is recognized as a compliance cost – approximates the cost of the replacement energy that would be provided by other generating units. Implicit in this assumption is that the variable production cost of the replacement energy sources is essentially the same as the energy price received, on the margin, for production of the replacement energy. This assumption is consistent with the market equilibrium concept that the variable production cost of the last generating unit to be dispatched will be approximately the same as the price received for the last unit of production. Finally, EPA assumes in its social cost analysis that the regulation does not affect the aggregate quantity of electricity that would be sold to consumers and, thus, that the regulation's social cost will include no loss in consumer and producer surplus from lost electricity sales *by the electricity industry in aggregate*. Given the very small impact of the regulation on electricity production cost for the total industry, EPA believes this assumption is reasonable the social cost analysis.

Other components of social costs include costs to federal and state governments of administering the permitting and compliance monitoring activities under the proposed regulation.[2] *Chapter B5: UMRA Analysis* presents more information on state and federal implementation costs.

EPA's estimate of social costs includes three components:

- (1) direct costs of compliance incurred by in-scope facilities,
- (2) administrative costs incurred by state governments, and
- (3) administrative costs incurred by the federal government.

The estimated after-tax annualized compliance costs incurred by facilities under the proposed Phase II rule are $182 million (see *Chapter B1: Summary of Compliance Costs*, Table B1-6). The estimated social value of these compliance costs, calculated on a pre-tax basis is $279 million. EPA estimates that state implementation costs for the proposed rule are $3.6 million annually and that federal implementation costs are approximately $62,000. The estimated total social costs of the Proposed Phase II Existing Facilities Rule are therefore $283 million.

Total social costs for the four alternative regulatory options range from $300 million for the impingement mortality and entrainment controls everywhere option (Option 3a) to $3,507 million for the all cooling towers option (Option 4).[3]

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[1] Costs incurred by government facilities and cooperatives are not adjusted for taxes, since these facilities are not subject to income taxes.

[2] State and federal implementation costs were developed for the proposed rule and Options 1 and 2 only. EPA assumed that the costs for Option 3a would be similar to the proposed rule and that the costs for Options 4 and 5 would be similar to Option 1.

[3] Note that EPA did not develop costs for Option 6.

Table D1-2 summarizes the total private and social costs of the proposed rule and five alternative regulatory options.

Table D1-2: Total Private and Social Costs of Compliance by Option ($2001; million)

Option		Total Private Compliance Costs to Facilities (Post-tax)	Social Costs			
			Pre-Tax Compliance Costs to Facilities	State Implementation Costs	Federal Implementation Costs	Total Social Costs
Waterbody/ Capacity-Based Option (Allows two tracks)	All Track I (Option 1)	$595	$968	$1.4	$0.04	$969
	Track I and II (Option 2)	$379	$609	$1.4	$0.04	$610
Proposed Rule (Option 3) **Alternative less stringent requirements based on both costs and benefits are allowed.**		**$182**	**$279**	**$3.6**	**$0.1**	**$283**
Impingement Mortality and Entrainment Controls Everywhere Option (Option 3a)		$195	$296	$3.6	$0.1	$300
All Cooling Towers Option (Option 4)		$2,316	$3,506	$1.4	$0.04	$3,507
Dry Cooling Option (Option 5)		$1,252	$2,052	$1.4	$0.04	$2,054
Waterbody-Based Option (Option 6)		Not costed. Costs expected to be greater than Option 1 (51 have flow reduction), but significantly less than Option 5 (417 have flow reduction).				

Source: U.S. EPA analysis, 2002.

D1-2 Summary of National Benefits and Social Costs

The summary of national benefit estimates for the proposed option and five regulatory options is reported in *Chapter C4: Benefits*. Table D1-3 presents EPA's national social cost and benefit estimates for the proposed Phase II rule and five alternative regulatory options. The table shows that the proposed rule, the impingement mortality and entrainment controls everywhere option, and the waterbody/capacity-based option all have estimated benefits that exceed social costs. The all cooling towers option and dry cooling option have negative net benefits (i.e., social costs exceed benefits). The Agency's proposed rule has the largest estimated net benefits, $452 million, of the five regulatory options analyzed.

Table D1-3: Total National Social Costs, Benefits, and Net Benefits by Option ($2001; million)

Option		Total Benefits	Total Social Costs	Net Benefits (Benefits minus Costs)
Waterbody/ Capacity-Based Option (Allows two tracks)	All Track I (Option 1)	$1,034	$969	$65
	Track I and II (Option 2)	$890	$610	$280
Proposed Rule (Option 3) **Alternative less stringent requirements based on both costs and benefits are allowed.**		**$735**	**$283**	**$452**
Impingement Mortality and Entrainment Controls Everywhere Option (Option 3a)		$749	$300	$449
All Cooling Towers Option (Option 4)		$1,223	$3,507	($2,284)
Dry Cooling Option (Option 5)		$1,536	$2,054	($518)
Waterbody-Based Option (Option 6)		$1,159	Not costed: greater than Option 1, significantly less than Option 5.	N/A

Source: U.S. EPA analysis, 2002.

GLOSSARY

opportunity cost: The lost value of alternative uses of resources (capital, labor, and raw materials) used in pollution control activities.

social costs: The costs incurred by society as a whole as a result of the proposed rule. Social costs do not include costs that are transfers among parties but that do not represent a net cost overall.

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