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

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Chapter A1: Introduction and Overview

Introduction

Chapter Contents

EPA is promulgating 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 Final Section 316(b) Phase II Existing Facilities Rule establishes national technology-based performance requirements applicable to the location, design, construction, and capacity of cooling water intake structures (CWIS) at existing facilities. The final national requirements 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 Summary of the Final Rule

The Final Section 316(b) Phase II Existing Facilities Rule establishes national standards applicable to the location, design, construction, and capacity of CWIS at Phase II existing facilities to minimize AEI. The requirements of the final 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for minimizing AEI associated with the CWIS based primarily on source water body type and the amount of cooling water withdrawn by a facility. For information on performance standards and compliance alternatives, please refer to the preamble of today's rule.

A1-2 Summary of Alternative Regulatory Options

For the final rule analysis, EPA did not consider any new alternative regulatory options other than those already analyzed for the proposed rule or the Notice of Data Availability. For a summary of previously considered alternative regulatory options, please refer to Chapter A1-4 of the Economic and Benefits Analysis (EBA) document in support of the proposed rule (U.S. EPA, 2002).

A1-3 Compliance Responses of the Final Rule

Table A1-1 shows compliance response assumptions for the final rule 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. The table shows that 149 of the 554 facilities are expected to install impingement controls; 205 are expected to install impingement and entrainment controls; and 200 are expected to install no new technologies in response to the final Phase II rule. Of the 200 facilities with no compliance action, 75 already meet the compliance requirements of the final rule because they already have a recirculating system.

Table A1-1: Number of Facilities by Waterbody Type and Compliance Assumption					
Facility Waterbody Type	**Impingement Controls Only**	**I&E Controls**	**No Action**	**Total**	**Recirculating System in Baseline (no action)**
Estuaries, Tidal Rivers, and Oceans	31	69	35	136	3
Great Lakes	1	32	24	57	4
Freshwater Streams and Rivers	48	103	96	247	42
Freshwater Lakes and Reservoirs	68	0	46	114	26
Total	**149**	**205**	**200**	**554**	**75**

Source: U.S. EPA analysis, 2004.

A1-4 ORGANIZATION OF THE EBA REPORT

The *Economic and Benefits Analysis for the Final Section 316(b) Phase II Existing Facilities Rule* (EBA) assesses the economic impacts and benefits of the final 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 and key definitions of the final rule.
- ***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 final rule and alternative regulatory options, presents EPA's assessment of compliance years, and presents the national cost of the final rule.
- ***Chapter B2: Cost Impact Analysis*** presents an assessment of the magnitude of compliance costs with the final Phase II rule, including a cost-to-revenue analysis at the facility and firm levels, an analysis of compliance costs per household at the North American Electric Reliability Council (NERC) level, and an analysis of compliance costs relative to electricity price projections, also at the NERC level.
- ***Chapter B3: Electricity Market Model Analysis*** presents an analysis of the final rule using an integrated electricity market model. The chapter discusses potential energy effects of the final 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 final 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 final rule.
- ***Chapter B6: Other Administrative Requirements*** presents several other analyses in support of the final Phase II rule. These analyses address the requirements of Executive Orders and Acts applicable to this rule.

PART C: NATIONAL BENEFITS

- ***Chapter C1: Regional Approach*** provides an overview of the regional study approach and a map of each study region.

- ***Chapter C2: Summary of Current Losses Due to I&E*** summarizes, for each regional study, the estimates of biological losses under current conditions and presents the estimated value of these losses. The chapter includes regional results and national totals.

- ***Chapter C3: Monetized Benefits*** presents the expected national reductions in I&E under the final rule and applies these reductions to the national baseline losses reported in Chapter C2 to obtain an estimate of national benefits attributable to section 316(b) Phase II regulation. The chapter includes regional results and national totals.

PART D: NATIONAL BENEFIT-COST ANALYSIS

- ***Chapter D1: Comparison of Costs and Benefits*** summarizes total private costs, develops social costs, and compares the final rule's total social costs and total benefits at the national level. The chapter also presents comparisons of benefits and costs at the regional level.

REFERENCES

Clean Water Act (CWA). 33 U.S.C. 1251 et seq.

U.S. Environmental Protection Agency (U.S. EPA). 2002. *Economic and Benefits Analysis for the Proposed Section 316(b) Phase II Existing Facilities Rule*. EPA-821-R-02-001. April 2002. DCN 4-0002. Available at http://www.epa.gov/ost/316b/econbenefits.

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).

Chapter A2: Need for the Regulation

Introduction

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 national standards for BTA has led to an inconsistent application of section 316(b). In fact, only 150 out of 554 Phase II facilities have indicated on EPA's 2000 Section 316(b) Industry Survey that they have ever performed an impingement and entrainment (I&E) study (U.S. EPA, 2000).

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.

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A2-1 Overview of Regulated Facilities

The Final 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 final Phase II rule does not cover (1) new steam electric power generating facilities, (2) new facilities in other industry sectors, (3) existing steam electric power generating facilities with a design intake flow of less than 50 MGD, and (4) existing facilities in other industry sectors.[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 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, 543 meet the "in-scope" requirements of this final rule. These 543 facilities represent 554 facilities in

[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 facilities in other industry sectors will be addressed by a separate rule (Phase III).

the industry.[2] Based on the survey, the 554 Phase II facilities account for approximately 216 BGD, or 98 percent of the estimated average flow of all power producers. Industrial categories other than power producers are not covered by this final 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 554 steam electric power generating facilities subject to the final Phase II rule comprise a substantial portion of the U.S. electric power market. As shown in Table A2-2, the 554 facilities represent 14 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 438,000 megawatt (MW; 50 percent of total), generate 2.4 billion megawatt hours of electricity (MWh; 59 percent of total), and realize $80 billion in revenues (52 percent of total).

[2] EPA applied sample weights to the 543 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	554	14%
Electric Generating Capacity (MW)	873,000	438,000	50%
Net Generation (million MWh)	4,060	2,400	59%
Revenues (in billions, $2001)	$154	$80	52%

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 final rule, see *Chapter B3: Electricity Market Model Analysis*.

b The IPM models 535 of the 543 Phase II facilities. Seven of the 535 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 528 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 (EPA electricity demand growth assumptions).

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, 302, or 54.5 percent, are coal-fired steam-electric facilities. The other major plant types are oil- or gas-fired steam-electric facilities (168, or 30.3 percent) and nuclear facilities (59, or 10.7 percent). The remaining 4.5 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 102 (18.4 percent) and 96 (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	92	1	6	3	0	**102**	**18.4%**
ERCOT	9	1	2	39	0	**51**	**9.2%**
FRCC	7	5	1	17	0	**30**	**5.4%**
HI	0	0	0	3	0	**3**	**0.5%**
MAAC	17	2	8	15	2	**45**	**8.1%**
MAIN	42	0	9	2	0	**53**	**9.6%**
MAPP	34	0	4	6	0	**44**	**7.9%**
NPCC	17	4	9	27	5	**61**	**11.0%**
SERC	56	1	17	22	0	**96**	**17.3%**
SPP	19	0	1	12	0	**32**	**5.8%**
WSCC	7	3	2	21	1	**35**	**6.3%**
Total	**302**	**17**	**59**	**168**	**8**	**554**	
Percent of Phase II	**54.5%**	**3.1%**	**10.7%**	**30.3%**	**1.4%**		

[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, 2001.

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 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 Saila et al., 1997). EPA estimates that CWIS used by the 554 facilities subject to the final rule impinge and entrain millions of age 1 equivalent fish annually (see Table C2-1 in *Chapter C2: Summary of Current Losses Due to I&E* 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 554 in-scope Phase II facilities with respect to these technologies.

a. Cooling water system (CWS) configuration and CWIS technologies

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 554 in-scope Phase II facilities, 75 (14 percent) reported the use of closed-cycle cooling systems.

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 554 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.

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		Total	
	#	%	#	%	#	%	#	%	#	%
Intake screening technologies	26	6.2%	0	0.0%	4	8.0%	0	0.0%	30	5.4%
Passive intake systems	44	10.5%	11	14.7%	9	18.0%	1	11.1%	65	11.7%
Fish diversion or avoidance systems	17	4.0%	2	2.7%	2	4.0%	0	0.0%	21	3.8%
Fish handling or return technologies	64	15.2%	5	6.7%	7	14.0%	2	22.2%	78	14.1%
Other/none/unknown	219	52.1%	50	66.7%	23	46.0%	5	55.6%	297	53.6%
Combination of technologies	50	11.9%	7	9.3%	5	10.0%	1	11.1%	63	11.4%
Total	**420**	**100.0%**	**75**	**100.0%**	**50**	**100.0%**	**9**	**100.0%**	**554**	**100.0%**

Source: *U.S. EPA, 2000; U.S. EPA analysis, 2004.*

b. 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 A2-5 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 intake flow of these facilities totaled 32 percent of the total cooling water being withdrawn by all in-scope Phase II facilities. The remaining 419 facilities (68 percent of flow) were reported as being located on fresh waterbodies (including Great Lakes).

Table A2-5: Estimated Number of Facilities and Share of Intake Flow by Source of Waterbody Type (Design Flow >= 50 MGD)

Waterbody Type	Number of Facilities	Percent of Total	Percent of Average Annual Intake Flow
Estuary/Tidal River	113	20%	25%
Ocean	22	4%	6%
Great Lake	57	10%	10%
Freshwater Stream/River	247	45%	32%
Lake/Reservoir	114	21%	27%
Total[a]	**554**	**100%**	**100%**

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

Source: *U.S. EPA, 2000.*

A2-2.2 Reducing Adverse Environmental Impacts

There are multiple types of adverse environmental impacts associated with CWIS, including impingement and entrainment; reductions of threatened, endangered, or other protected species; damage to ecologically critical aquatic organisms, including important elements of the food chain; diminishment of a population's potential compensatory reserve; losses to populations, including reductions of indigenous species populations, commercial fishery stocks, and recreational fisheries; and stresses to overall communities or ecosystems as evidenced by reductions in diversity or other changes in system structure or function.

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.

Impingement and entrainment losses can be substantial. For example, it is estimated that annual entrainment at three Hudson River power plants results in year-class reductions of up to 20 percent for striped bass, 25 percent for bay anchovy, and 43 percent for Atlantic tomcod, even without assuming 100 percent mortality of entrained organisms (ConEd, 2000). At the San Onofre Nuclear Generating Station (SONGS), it was estimated that in a normal (non-El Nino) year 57 tons of fish were killed per year when all units were in operation (Murdoch, et al., 1989).[3] This included approximately 350,000 juvenile white croaker, a popular sport fish. This number represents 33,000 adult individuals or 3.5 tons of adult fish. It was found that losses at SONGS resulted in a 50 to 70 percent decline in local midwater fish within three kilometers of the plant.

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 estimated reduction in impingement and entrainment as a result of the final Phase II rule. See also the *Regional Studies for the Final Section 316(b) Phase II Existing Facilities Rule* (U.S. EPA, 2004) for detailed information on baseline losses.

A2-2.3 Addressing Market Imperfections

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 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 reimbursed 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 consequence 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

[3] Unit 1, which accounted for about 20% of total losses, was taken out of operation in November 1992.

subgroups 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.

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 A2-6 on the following page illustrates a variety of ways in which States identify the section 316(b) requirements.

Table.A2-6: 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, 1994.

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).

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. 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, EPA implements section through its regional offices.

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.

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Chapter A3: Profile of the Electric Power Industry

Introduction

This profile compiles and analyzes economic and operational 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 Final 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 final 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, capacity, and geographic distribution.
- Section A3-3 focuses on the Phase II section 316(b) facilities. This section provides information on the physical, geographic, and ownership characteristics of the 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 2025.

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; U.S. DOE, 2000a):[1]

- The ***generation*** sector includes the power plants that produce, or "generate," electricity.[2] Electric power is usually produced by a mechanically driven rotary generator called a turbine. Generator drivers, also called prime movers, include gas or diesel internal combustion machines, as well as streams of moving fluid such as wind, water from a hydroelectric dam, or steam from a boiler. Most boilers are heated by direct combustion of fossil or biomass-derived fuels or waste heat from the exhaust of a gas turbine or diesel engine, but heat from nuclear, solar, and geothermal sources is also used. Electric power may also be produced without a generator by using electrochemical, thermoelectric, 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, oil, and natural gas) as an energy source and employ some type of turbine to produce electricity. According to the Department of Energy, the most common prime movers are (U.S. DOE, 2000a):

- ***Steam Turbine:*** "Most of the electricity in the United States is produced in steam turbines. In a fossil-fueled steam turbine, the fuel is burned in a boiler to produce steam. The resulting steam then turns the turbine blades that turn the shaft of the generator to produce electricity. In a nuclear-powered steam turbine, the boiler is replaced by a reactor containing a core of nuclear fuel (primarily enriched uranium). Heat produced in the reactor by fission of the uranium is used to make steam. The steam is then passed through the turbine generator to produce electricity, as in the fossil-fueled steam turbine. Steam-turbine generating units are used primarily to serve the ***base load*** of electric utilities. Fossil-fueled steam-turbine generating units range in size (***nameplate capacity***) from 1 ***megawatt*** to more than 1,000 megawatts. The size of nuclear-powered steam-turbine generating units in operation today ranges from 75 megawatts to more than 1,400 megawatts."

- ***Gas Turbine:*** "In a gas turbine (combustion-turbine) unit, hot gases produced from the combustion of natural gas and distillate oil in a high-pressure combustion chamber are passed directly through the turbine, which spins the generator to produce electricity. Gas turbines are commonly used to serve the peak loads of the electric utility. Gas-turbine units can be installed at a variety of site locations, because their size is generally less than 100 megawatts. Gas-turbine units also have a quick startup time, compared with steam-turbine units. As a result,

[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.

gas-turbine units are suitable for ***peakload***, emergency, and reserve-power requirements. The gas turbine, as is typical with peaking units, has a lower efficiency than the steam turbine used for baseload power."

- ***Combined-Cycle Turbine:*** "The efficiency of the gas turbine is increased when coupled with a steam turbine in a combined-cycle operation. In this operation, hot gases (which have already been used to spin one turbine generator) are moved to a waste-heat recovery steam boiler where the water is heated to produce steam that, in turn, produces electricity by running a second steam-turbine generator. In this way, two generators produce electricity from one initial fuel input. All or part of the heat required to produce steam may come from the exhaust of the gas turbine. Thus, the steam-turbine generator may be supplementarily fired in addition to the waste heat. Combined-cycle generating units generally serve ***intermediate loads***."

- ***Internal Combustion Engine:*** "These prime movers have one or more cylinders in which the combustion of fuel takes place. The engine, which is connected to the shaft of the generator, provides the mechanical energy to drive the generator to produce electricity. Internal-combustion (or diesel) generators can be easily transported, can be installed upon short notice, and can begin producing electricity nearly at the moment they start. Thus, like gas turbines, they are usually operated during periods of high demand for electricity. They are generally about 5 megawatts in size."

- ***Hydroelectric Generating Units***: "Hydroelectric power is the result of a process in which flowing water is used to spin a turbine connected to a generator. The two basic types of hydroelectric systems are those based on falling water and natural river current. In the first system, water accumulates in reservoirs created by the use of dams. This water then falls through conduits (penstocks) and applies pressure against the turbine blades to drive the generator to produce electricity. In the second system, called a run-of-the-river system, the force of the river current (rather than falling water) applies pressure to the turbine blades to produce electricity. Since run-of-the-river systems do not usually have reservoirs and cannot store substantial quantities of water, power production from this type of system depends on seasonal changes and stream flow. These conventional hydroelectric generating units range in size from less than 1 megawatt to 700 megawatts. Because of their ability to start quickly and make rapid changes in power output, hydroelectric generating units are suitable for serving peak loads and providing spinning reserve power, as well as serving baseload requirements. Another kind of hydroelectric power generation is the pumped storage hydroelectric system. Pumped storage hydroelectric plants use the same principle for generation of power as the conventional hydroelectric operations based on falling water and river current. However, in a pumped storage operation, low-cost off-peak energy is used to pump water to an upper reservoir where it is stored as potential energy. The water is then released to flow back down through the turbine generator to produce electricity during periods of high demand for electricity."

In addition, there are a number of other prime movers:

- ***Other Prime Movers:*** "Other methods of electric power generation, which presently contribute only small amounts to total power production, have potential for expansion. These include geothermal, solar, wind, and biomass (wood, municipal solid waste, agricultural waste, etc.). Geothermal power comes from heat energy buried beneath the surface of the earth. Although most of this heat is at depths beyond current drilling methods, in some areas of the country, magma--the molten matter under the earth's crust from which igneous rock is formed by cooling--flows close enough to the surface of the earth to produce steam. That steam can then be harnessed for use in conventional steam-turbine plants. Solar power is derived from the energy (both light and heat) of the sun. Photovoltaic conversion generates electric power directly from the light of the sun; whereas, solar-thermal electric generators use the heat from the sun to produce steam to drive turbines. Wind power is derived from the conversion of the energy contained in wind into electricity. A wind turbine is similar to a typical wind mill. However, because of the intermittent nature of sunlight and wind, high capacity utilization factors cannot be achieved for these plants. Several electric utilities have incorporated wood and waste (for example, municipal waste, corn cobs, and oats) as energy sources for producing electricity at their power plants. These sources replace fossil fuels in the boiler. The combustion of wood and waste creates steam that is typically used in conventional steam-electric plants."

The section 316(b) regulation is only relevant for electric generators that use cooling water. However, not all prime movers require cooling water. Only prime movers with a steam electric generating cycle use large enough amounts of cooling water to fall under the scope of the final rule. This profile will, therefore, differentiate between steam electric and other prime movers. EPA identified steam electric prime movers using data collected by the EIA (U.S. DOE, 2001a).[3] For this profile, the following prime movers, including both steam turbines and combined-cycle technologies, are classified as steam electric:

- Steam Turbine, including nuclear, geothermal, and solar steam (not including combined cycle),
- Combined Cycle Steam Part,
- Combined Cycle Combustion Turbine Part,
- Combined Cycle Single Shaft (combustion turbine and steam turbine share a single generator), and
- Combined Cycle Total Unit (used only for plants/generators that are in the planning stage).

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 Form EIA-860 (Annual Electric Generator Report) in 2001. 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 generating capacity.

Table A3-1: Number of Existing Utility and Nonutility Plants by Prime Mover, 2001

Prime Mover	Utility[a]	Nonutility[a]
	Number of Plants	Number of Plants
Steam Turbine	636	903
Combined-Cycle	59	239
Gas Turbine	308	426
Internal Combustion	557	346
Hydroelectric	900	490
Other	22	134
Total	**2,482**	**2,538**

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

Source: U.S. DOE, 2001a.

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, 2003a):

- ***Utility:*** A regulated entity providing electric power, traditionally vertically integrated. Utilities all have distribution facilities for delivery of electric energy for use primarily by the public, but they 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.

- ***Nonutility:*** Entities that generate power for their own use and/or for sale to utilities and others. Nonutility power producers include cogenerators (combined heat and 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 (adapted from U.S. DOE, 2000a).

[3] U.S. DOE, 2001a (EIA Form 860, Annual Electric Generator Report) collects data used to create an annual inventory of all units, plants, and 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.

❖ *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 to give consumers access to services under similar conditions. Most IOUs engage in generation, transmission, and distribution. In 2001, IOUs operated 1,147 facilities, which accounted for approximately 44 percent of all U.S. electric generation capacity (U.S. DOE, 2001a; U.S. DOE, 2001b).

❖ *Publicly-owned utilities*

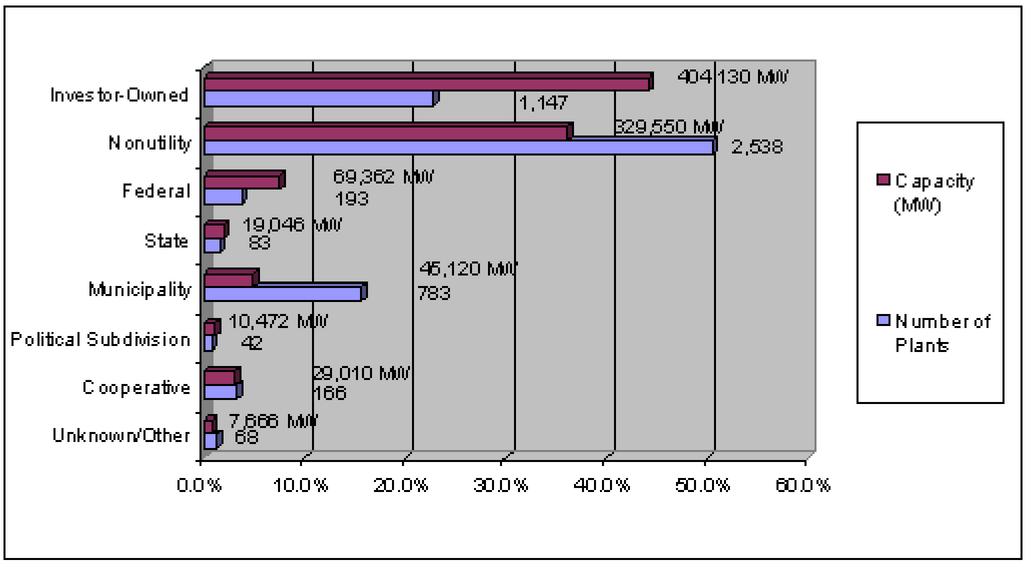
Publicly-owned electric utilities can be State authorities, municipalities, and political subdivisions (e.g., public power districts, irrigation projects, and other State agencies established to serve their local municipalities or nearby communities). This profile also includes Federally-owned facilities in this category. Excess funds or "profits" from the operation of these utilities are put toward reducing rates, increasing facility efficiency and capacity, and funding community programs and local government budgets. 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 2001, the Federal government operated 193 facilities (accounting for 7.6 percent of total U.S. electric generation capacity), States owned 83 facilities (2.1 percent of U.S. capacity), municipalities owned 783 facilities (4.9 percent of U.S. capacity), and political subdivisions operated 42 facilities (1.1 percent of U.S. capacity) (U.S. DOE, 2001a; U.S. DOE, 2001b).

❖ *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 47 States and are incorporated under State laws. In 2001, rural electric cooperatives operated 166 generating facilities and accounted for approximately 3 percent of all U.S. electric generation capacity (U.S. DOE, 2001a; U.S. DOE, 2001b).

Figure A3-1 presents the number of generating facilities and their capacity in 2001, by type of ownership. 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 Form EIA-860 in 2001. The graphic shows that nonutilities account for the largest percentage of facilities (2,538, or 52 percent), but only represent 38 percent of total U.S. generating capacity. Investor-owned utilities operate the second largest number of facilities, 1,143, and account for 46 percent of total U.S. capacity.

Figure A3-1: Distribution of Facilities and Capacity by Ownership Type, 2001



Source: U.S. DOE, 2001a; U.S. DOE, 2001b.

A3-2 Domestic Production

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

A3-2.1 Generating Capacity

Utilities own and operate the majority of the generating capacity (64 percent) and capability (65 percent) in the United States. Nonutilities owned only 35 percent of total capability in 2001. Nonutility capacity and capability have increased substantially in the past few years, since passage of legislation aimed at increasing competition in the industry. Nonutility capability has increased 637 percent between 1991 and 2001, compared with the

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.

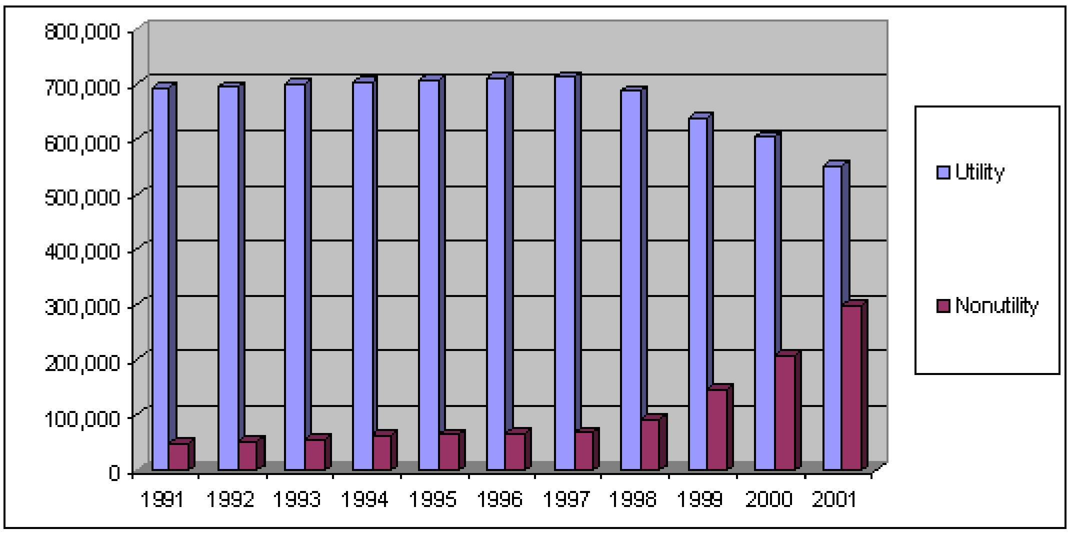
Net capability is the steady hourly output that the generating unit is expected to supply to the system load, as demonstrated by test procedures. The capability of the generating unit in the summer is generally less than in the winter due to high ambient-air and cooling-water temperatures, which cause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

U.S. DOE, 2000a

decrease in utility capability of 21 percent over the same time period.[4]

Figure A3-2 shows the growth in utility and nonutility capability from 1991 to 2001. The growth in nonutility capability, combined with a decrease in utility capability, has resulted in a modest growth in total generating capability. The significant increase in nonutility capability and decrease in utility capability since 1997 is attributable to utilities being sold to nonutilities.

Figure A3-2: Generating Capability, 1991 to 2001



Source: U.S. DOE, 2003a.

[4] 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 2001 was 3,734 billion kWh. Utility-owned plants accounted for 70 percent of this amount. Total net generation has increased by 22 percent over the 11 year period from 1991 to 2001. During this period, nonutilities increased their electricity generation by 343 percent. In comparison, generation by utilities decreased by 7 percent (U.S. DOE, 2003a; 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 2001 by energy source and ownership type.

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 2001 (GWh)

Energy Source	Utilities			Nonutilities			Total		
	1991	2001	% Change	1991	2001	% Change	1991	2001	% Change
Coal	1,551	1,560	0.6%	39	343	769.9%	1,591	1,903	19.7%
Hydropower	276	190	-31.0%	9	17	95.2%	284	208	-27.0%
Nuclear	613	534	-12.8%	0	235	n/a	613	769	25.5%
Oil	111	79	-29.2%	8	49	487.7%	120	128	6.6%
Natural Gas	264	264	0.1%	117	365	210.8%	382	629	64.9%
Other Gases	0	0	n/a	11	14	21.4%	11	14	21.4%
Renewables[a]	10	2	-78.8%	59	77	30.9%	69	79	14.7%
Other[b]	0	0	n/a	5	4	-10.3%	5	4	-10.2%
Total	**2,825**	**2,630**	**-6.9%**	**249**	**1,104**	**343.6%**	**3,074**	**3,734**	**21.5%**

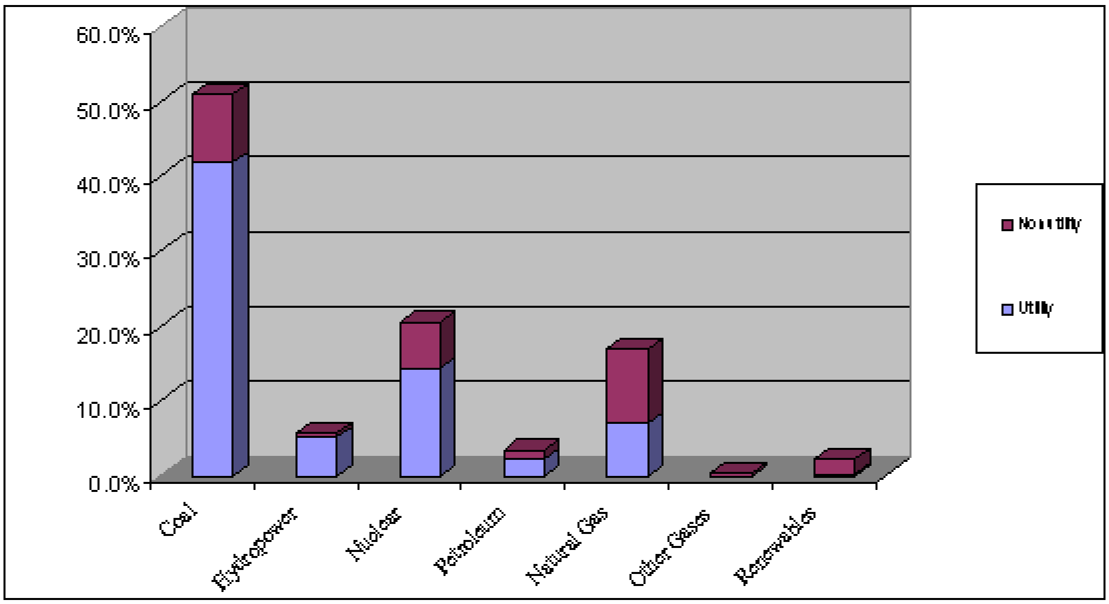
[a] Renewables include solar, wind, wood, biomass, and geothermal energy sources.
[b] Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.

Source: U.S. DOE, 2002b; U.S. DOE, 2002c; U.S. DOE, 1995a; U.S. DOE, 1995b.

As shown in Table A3-2, natural gas generation grew the fastest among the fuel source categories, increasing by 65 percent between 1991 and 2001. Nuclear generation increased by 26 percent, while coal generation increased by 20 percent. Generation from renewable energy sources increased 15 percent. Hydropower, however, experienced a decline of 27 percent. For utilities, generation using natural gas and coal as fuel sources was relatively constant. Generation using other sources fell, mostly because of sales to nonutilities. Nonutility generation grew quickly between 1991 and 2001 with the passage of legislation aimed at increasing competition in the industry. Nonutility coal generation grew the fastest among the energy source categories, increasing 770 percent between 1991 and 2001. Generation from oil-fired facilities also increased substantially, with a 488 percent increase in generation between 1991 and 2001.

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 51 percent of total 2001 generation. Electric utilities generate 82 percent (1,560 billion kWh) of the 1,903 billion kWh of electricity generated by coal-fired plants. This represents approximately 59 percent of total utility generation. The remaining 18 percent (343 billion kWh) of coal-fired generation is provided by nonutilities, accounting for 31 percent of total nonutility generation. The second largest source of electricity generation is nuclear power plants, accounting for 20 percent total utility generation and 21 percent of nonutility generation. Another significant source of electricity generation is gas-fired power plants, which account for 33 percent of nonutility generation and 17 percent of total generation.

Figure A3-3: Percent of Electricity Generation by Primary Fuel Source, 2001



Source: U.S. DOE, 2003a.

The final Phase II rule will affect facilities differently based on the fuel sources and prime movers used to generate electricity. As described 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 with or have links to the Canadian grid system. The Western and Texas systems have links with Mexico.

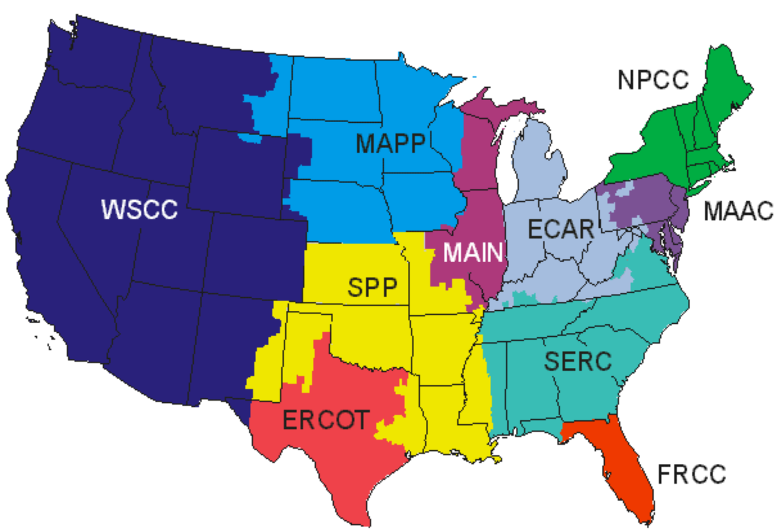
These major networks contain extra-high voltage connections that allow for power transactions from one part of the network to another. Wholesale transactions can take place within these networks to reduce power costs, increase supply options, and ensure system reliability. ***Reliability*** refers to 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 ten regional councils that cover the 48 contiguous States, and affiliated councils that cover 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 above, 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 (HICC).

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



Source: U.S. DOE, 1996a; U.S. DOE, 1996b.

The final Phase II rule may affect plants located in different NERC regions differently. Economic characteristics of existing facilities affected by the final 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 final Phase II rule on profitability, electricity prices, and other impact measures. However, as discussed in *Chapter B3: Electricity Market Model Analysis*, the final Phase II rule will have little or no impact on electricity prices in each region since the final Phase II rule is relatively inexpensive relative to the overall production costs in any region.

Table A3-3 shows the distribution of all existing plants and capacity by NERC region. The table shows that 1,306 plants, equal to 26 percent of all facilities in the U.S., are located in the Western Systems Coordinating Council (WSCC). However, these plants account for only 17 percent of total national capacity. Conversely, only 13 percent of generating plants are located in the Southeastern Electric Reliability Council (SERC), yet these plants account for 22 percent of total national capacity.

Table A3-3: Distribution of Existing Plants and Capacity by NERC Region, 2001

NERC Region	Plants		Capacity	
	Number	% of Total	Total MW	% of Total
ASCC	124	2.5%	2,261	0.2%
ECAR	448	8.9%	128,301	14.0%
ERCOT	215	4.3%	80,523	8.8%
FRCC	129	2.6%	45,736	5.0%
HICC	34	0.7%	2,452	0.3%
MAAC	246	4.9%	63,676	7.0%
MAIN	412	8.2%	70,568	7.7%
MAPP	445	8.9%	37,410	4.1%
NPCC	718	14.3%	69,861	7.6%
SERC	661	13.2%	204,538	22.4%
SPP	282	5.6%	51,743	5.7%
WSCC	1,306	26.0%	157,287	17.2%
Total	**5,020**	**100%**	**914,356**	**100%**

Source: U.S. DOE, 2001a.

A3-3 Plants Subject to Phase II Regulation

Section 316(b) of the Clean Water Act applies to point source facilities which use or propose to use a cooling water intake structure that withdraws cooling water directly from a surface waterbody 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.

The following sections describe power plants that are subject to the Final Section 316(b) Phase II Existing Facilities Rule. The final Phase II rule applies to existing steam electric power generating 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 National Pollutant Discharge Elimination System (NPDES) permit or are required to obtain one; and
- they have a design intake flow of 50 million gallons per day (MGD) or greater.

The final 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 543 steam electric power generating facilities identified in EPA's 2000 Section 316(b) Industry Survey as being "in-scope" of this final rule. These 543 facilities represent 554 facilities nation-wide.[5] The remainder of this chapter will refer to these facilities as "Phase II facilities" or "Phase II plants."

The following sections present a variety of physical, geographic, and ownership information about the Phase II facilities. Topics discussed include:

- ***Ownership type:*** Section A3-3.1 discusses Phase II facilities with respect to the entity that owns them.
- ***Ownership size:*** Section A3-3.2 presents information on the entity size of the owners of Phase II facilities.
- ***Plant size:*** Section A3-3.3 discusses the size distribution of Phase II facilities by generation capacity.
- ***Geographic distribution:*** Section A3-3.4 discusses the distribution of Phase II facilities by NERC region.
- ***Water body and cooling system type:*** Section A3-3.5 presents information on the type of waterbody from which Phase II facilities draw their cooling water and the type of cooling system they operate.

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

A3-3.1 Ownership Type

Utilities can be divided into seven major ownership categories: investor-owned utilities, nonutilities, Federally-owned utilities, State-owned utilities, municipalities, political subdivisions, and rural electric cooperatives. This classification is important because EPA has separately considered impacts on governments in its regulatory development (see *Chapter B5: UMRA Analysis* for the analysis of government impacts of the final Phase II rule).

[5] EPA applied sample weights to the 543 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 A3-4 shows the number of parent entities, plants, and capacity by ownership type. Numbers are presented for the industry as a whole and the portion of the industry subject to section 316(b) Phase II regulation. Overall, four percent of all parent entities, 11 percent of all plants, and 53 percent of all capacity is subject to Phase II regulation. The table further shows that the majority of Phase II plants, or 274 plants, are owned by investor-owned utilities. An additional 179 Phase II plants are owned by nonutilities. A higher percentage of the plants owned by investor-owned utilities (24 percent) and rural electric cooperatives (15 percent) are Phase II facilities, compared to the percentage of facilities in other ownership categories. 66.5 percent of capacity owned by investor-owned utilities is subject to the final Phase II rule.

Table A3-4: Existing Parent Entities, Plants, and Capacity by Ownership Type, 2001[a]

Ownership Type	Parent Entities			Plants			Capacity (MW)		
	Total[b]	With Phase II Plants	% Phase II Plants	Total[b]	Phase II[c]	% Phase II	Total[b]	Phase II[c]	% Phase II
Investor-Owned	359	41	11.4%	1,147	274	23.9%	404,130	268,643	66.5%
Nonutility[d]	n/a	26	n/a	2,538	179	7.0%	329,550	154,844	47.0%
Federal	9	1	11.1%	193	14	7.3%	69,362	27,798	40.1%
State	27	4	14.8%	83	7	8.4%	19,046	5,409	28.4%
Municipal	1,868	36	1.9%	783	48	6.1%	45,120	17,763	39.4%
Political Subdivision	120	3	2.5%	42	7	6.7%	10,472	4,123	39.4%
Cooperative	889	15	1.7%	166	25	15.1%	29,010	8,821	30.4%
Unknown	0	0	0.0%	68	0	0.0%	7,666	0	0.0%
Total	3,272	126	3.9%	5,020	554	11.0%	914,356	487,401	53.3%

[a] Numbers may not add up to totals due to independent rounding.
[b] Information on the total number of parent entities is based on data from Form EIA-861 (U.S. DOE, 2001b). Information on plants and capacity is based on data from Form EIA-860 (U.S. DOE, 2001a). These two data sources report information for non-corresponding sets of power producers. Therefore, the total number of parent entities is not directly comparable to the information on total plants or total capacity.
[c] The number of Phase II plants and capacity was sample weighted to account for survey non-respondents.
[d] Form EIA-861 does not provide information for nonutilities.

Source: U.S. EPA, 2000; U.S. DOE, 2001a; U.S. DOE, 2001b.

A3-3.2 Ownership Size

EPA estimates that 25 of the 126 entities owning Phase II facilities (20 percent) are small.[6] The size distribution varies considerably by ownership type: only three percent of Phase II investor-owned utilities and four percent of Phase II nonutilities are small, compared to 44 percent of Phase II municipalities, 40 percent of Phase II cooperatives, and 33 percent of Phase II political subdivisions. In general, entities that own Phase II plants are larger than other entities in the industry. Out of 3,272 parent entities in the industry as a whole, 1,992 entities, or 62 percent, are small, compared to 20 percent of Phase II facilities.

For a detailed discussion of the identification and size determination of parent entities see *Chapter B4: Regulatory Flexibility Analysis*. That chapter also documents how EPA considered the economic impacts on small entities when developing this regulation.

[6] See Chapter B4 for information on EPA's small entity analysis.

Table A3-5: Existing Parent Entities by Ownership Type and Size, 2001										
Ownership Type	Total Number of Parent Entities[a]					Total Number of Parent Entities That Own Phase II Facilities [b]				% of Small Entities That Own Phase II Facilities
	Small	Large	Unknown	Total	% Small	Small	Large	Total	% Small	
Investor-Owned	35	307	17	359	9.9%	1	40	41	2.4%	2.8%
Nonutility[c]	n/a	n/a	n/a	n/a	n/a	1	25	26	3.8%	n/a
Federal	-	9	-	9	0%	-	1	1	0.0%	0.0%
State	-	27	-	27	0%	-	4	4	0.0%	0.0%
Municipal	983	884	1	1,868	52.6%	16	20	36	44.4%	1.6%
Political Subdivision	111	9	-	120	92.5%	1	2	3	33.3%	0.9%
Cooperative	862	25	2	889	97.0%	6	9	15	40.0%	0.7%
Total	**1,992**	**1,260**	**20**	**3,272**	**61.5%**	**25**	**101**	**126**	**19.8%**	**1.3%**

[a] The total number of parent entities that own generation utilities is based on data from Form EIA-861 (U.S. DOE, 2001b). Most of the other industry-wide information in this profile is based on data from Form EIA-860 (U.S. DOE, 2001a). Since these two forms report data for differing sets of facilities, the information in this table is not directly comparable to the other information presented in this profile.

[b] Numbers may not add up to totals due to independent rounding.

[c] Form EIA-861 does not provide data on nonutilities.

Source: U.S. EPA analysis, 2004.

Table A3-6 presents the number of Phase II facilities that are owned by small entities. The table shows that 25 of the 554 Phase II facilities are owned by small entities. Almost all of the small Phase II facilities are owned by municipalities and rural electric cooperatives. Only a small fraction of the facilities owned by nonutilities, investor-owned utilities, and political subdivisions have small parent entities. By definition, States and the Federal government are considered large parent entities.

Table A3-6: Phase II Facilities by Ownership Type and Size, 2001

Ownership Type	Number of Phase II Facilties[a, b]			
	Small	Large	Total	% Small
Investor-Owned	1	273	274	0.4%
Nonutility	1	178	179	0.6%
Federal	0	14	14	0.0%
State	0	7	7	0.0%
Municipal	16	32	48	33.3%
Political Subdivision	1	6	7	14.3%
Cooperative	6	19	25	24.0%
Total	25	529	554	5%

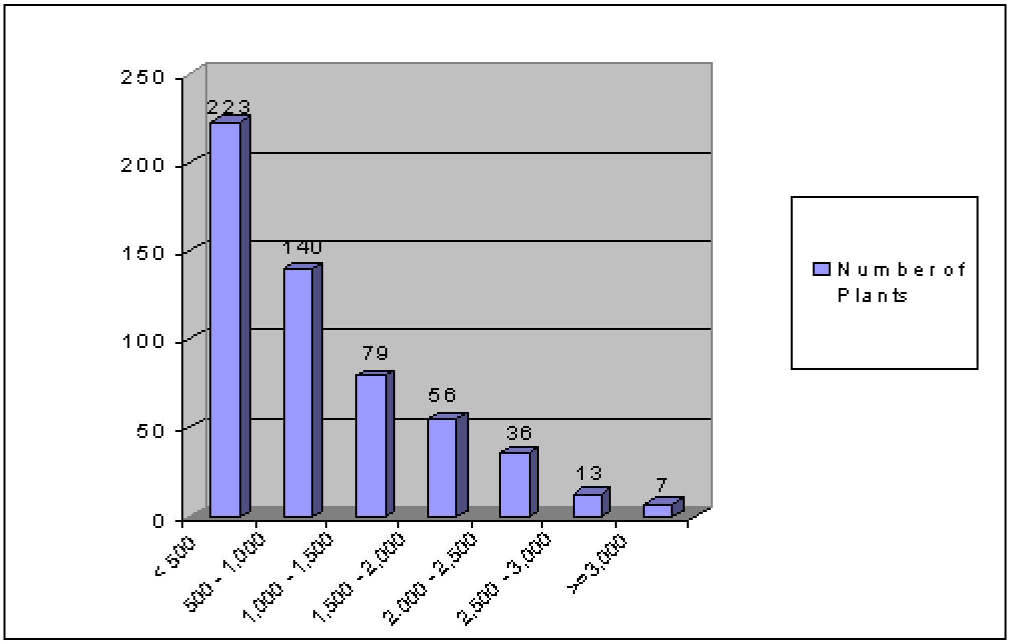
[a] Numbers may not add up to totals due to independent rounding.
[b] All numbers were sample weighted to account for survey non-respondents.

Source: U.S. EPA analysis, 2004.

A3-3.3 Plant Size

EPA also analyzed the Phase II facilities with respect to their generating capacity. The size of a plant is important because it partly determines its need for cooling water and its importance in meeting electricity demand and reliability needs. Figure A3-5 shows that while some Phase II plants have very large generating capacities, most have moderate capacities. Of the 554 Phase II plants, 223 plants (40 percent) have a capacity of less than 500 MW; 363 plants (65 percent) have a capacity of less than 1,000 MW. Only seven facilities have a capacity of greater than 3,000 MW. Of the 223 plants with capacities less than 500 MW, 96 have a capacity between 250 and 500 MW, 78 have a capacity between 100 and 250 MW, and 49 have a capacity of less than 100 MW.

Figure A3-5: Number of Phase II Facilities by Plant Size (in MW), 2001 [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, 2001a.

A3-3.4 Geographic Distribution

The geographic distribution of facilities is important because a high concentration of facilities with regulatory compliance costs 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. Table A3-7 shows the distribution of Phase II plants by NERC region. The table shows that there are considerable differences between the regions both in terms of the number of Phase II plants and the percentage of all plants that they represent. Excluding Alaska, which has only one Phase II facility, the percentage of Phase II facilities ranges from three percent in the Western Systems Coordinating Council (WSCC) to 24 percent in the Electric Reliability Council of Texas (ERCOT). The Southeastern Electric Reliability Council (SERC) has the highest absolute number of Phase II facilities with 103 facilities, or 16 percent of all facilities in the region, followed by the East Central Area Reliability Coordination Agreement (ECAR) with 98 facilities, or 22 percent of all facilities in the region.

Table A3-7: Existing Plants by NERC Region, 2001

NERC Region	Total Number of Facilities	Phase II Facilities[a,b]	
		Number	% of Total in Region
ASCC	124	1	1%
ECAR	448	98	22%
ERCOT	215	51	24%
FRCC	129	27	21%
HICC	34	3	9%
MAAC	246	46	19%
MAIN	412	60	15%
MAPP	445	37	8%
NPCC	718	61	9%
SERC	661	103	16%
SPP	282	30	11%
WSCC	1,306	36	3%
Total	**5,020**	**554**	**11%**

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

Source: U.S. EPA, 2000; U.S. DOE, 2001a.

A3-3.5 Waterbody and Cooling System Type

Table A3-8 shows that most of the Phase II facilities draw water from a freshwater river (247 plants or 44 percent). The next most frequent waterbody types are lakes or reservoirs (114 plants or 21 percent) and estuaries or tidal rivers (113 plants or 20 percent). The table also shows that most of the Phase II plants (420 plants or 76 percent) employ a once-through cooling system.[7] Of the 113 plants that withdraw from an estuary, the most sensitive type of waterbody, only three percent use a recirculating system while 88 percent have a once-through system. Plants with once-through cooling water systems withdraw between 70 and 98 percent more water than those with recirculating systems.

[7] 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. Recirculating systems use cooling towers or ponds to cool water before passing it through condensers again.

Table A3-8: Number of Phase II Facilities by Water Body Type and Cooling System Type[a]

Waterbody Type	Cooling System Type								Total [b]
	Recirculating		Once-Through		Combination		Other		
	No.	% of Type	No.	% of Type	No.	% of Type	No.	% of Type	
Estuary/ Tidal River	3	3%	99	88%	10	9%	1	1%	**113**
Ocean	0	0%	22	100%	0	0%	0	0%	**22**
Lake/ Reservoir	26	23%	79	69%	8	7%	1	1%	**114**
Freshwater River	42	17%	169	68%	29	12%	6	2%	**247**
Great Lake	4	7%	50	88%	3	5%	0	0%	**57**
Total	**75**	**14%**	**420**	**76%**	**50**	**9%**	**8**	**1%**	**554**

[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, 2001a.

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 final section 316(b) Phase II rule. The most important change in the electric power industry is deregulation – the transition from a highly regulated monopolistic industry to a less regulated, more competitive industry. Section 3.4.1 discusses the current status of deregulation. Section 3.4.2 presents a summary of forecasts from the Annual Energy Outlook 2003.

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.[8] 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.

[8] 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).

- ***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 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 in 2000, has affected restructuring in that State and several others. Since those difficulties, five States (Arkansas, Montana, Nevada, New Mexico, and Oklahoma) have delayed the restructuring process pending further review of the issues while California has suspended direct retail access. As of 2002, seventeen States had operating competitive retail electricity markets, two others (Texas and Virginia) had just opened their markets to competition, and one (Oregon) had restarted its restructuring process. (U.S. DOE, 2002a).

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 2003* (U.S. DOE, 2003b). The EIA models future market conditions through the year 2025, 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 November 2002. EPA used ICF Consulting's Integrated Planning Model (IPM®), an integrated energy market model, to conduct the economic analyses supporting the 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 AEO2003 projects electricity demand to grow by approximately 1.8 percent annually between 2000 and 2025. This growth is driven by an estimated 2.2 percent annual increase in the demand for electricity from the commercial sector associated with a projected annual growth in commercial floor space of 1.6 percent. EIA expects electricity demand from the industrial sector to increase by 1.7 percent annually, largely in response to an increase in industrial output of 2.6 per year. Residential demand is expected to increase by 1.6 percent annually over the same forecast period, due mostly to an increase in the number of U.S. households of 1.0 percent per year between 2000 and 2025.

b. Capacity retirements

The AEO2003 projects that total fossil fuel-fired generation capacity to decline due to retirements. EIA forecasts that total fossil-steam capacity will decrease by an estimated 12 percent (or 78 gigawatts) between 2000 and 2025, including 56 gigawatts of oil and natural gas fired steam capacity. EIA estimates total nuclear capacity to decline by an estimated 3 percent (or 3 gigawatts) between 2000 and 2025 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.

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, 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 2025, approximately 80 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 17 percent of the additional capacity forecasted to come on line between 2000 and 2025 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 AEO2003 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 2025, its share of total generation is expected to decrease from 53 percent to an estimated 50 percent. This decrease in the share of coal generation is in favor of less capital-intensive and more efficient natural gas generation technologies. The share of total generation associated with gas-fired technologies is projected to increase from approximately 14 percent in 2000 to an estimated 27 percent in 2025, 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 real price of electricity, as well as the price paid by customers in each sector (residential, commercial, and industrial), to decrease between 2000 and 2008 as a result of competition among electricity suppliers, excess generating capacity, and a decline in coal prices. However, by 2025, EIA predicts that the average real price of electricity will return to 2000 levels as a result of rising natural gas costs and electricity demand growth.

GLOSSARY

Base Load: 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 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.

Hydroelectric Generating Unit: A unit in which the turbine generator is driven by falling water.

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)***.

Megawatt (MW): Unit of power equal to one million ***watts***.

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 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 turbines***, ***combined-cycles***, ***gas combustion turbines***, ***internal combustion engines***, and ***hydroelectric generating units***. 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)

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 Final Section 316(b) Phase II Existing Facilities Rule. EPA developed unit costs of complying with the various requirements of the final rule, including costs of section 316(b) technologies, energy costs, and administrative costs. Unit costs were then assigned to the 554 in-scope facilities, based on the facilities' modeled compliance responses, and aggregated to the national level.

CHAPTER CONTENTS

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 the final rule based on a variety of technologies for impingement mortality and entrainment reduction. 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 rule and on their projected compliance response. The unit costs used for the final rule analysis are engineering cost estimates, expressed in July 2002 dollars. More detail on the development of these unit costs is provided in the *Technical Development Document for the Final Section 316(b) Phase II Existing Facilities Rule,* hereafter referred to as the "*Phase II Technical Development Document*" (U.S. EPA, 2004b).

To characterize the existing facilities' current technologies, EPA compiled facility-level, cooling system, and intake structure data for the 227 in-scope 316(b) Detailed Questionnaire (DQ) respondents and, to the extent possible, for the 316 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. The result of the decision process assigned an intake technology module to each facility or intake that suited the particular site characteristics and would enable the facility to meet its compliance requirements. The Agency based its approach of assigning costing modules to model facilities on a combination of facility and intake-specific questionnaire data in addition to satellite photos and maps, where available. Because not all facilities received the same questionnaire, the Agency attempted to utilize data responses to questions that were asked in both the short-technical and detailed questionnaires whenever possible. In the end, the primary difference in data analysis between short-technical and detailed questionnaire respondents was the level at which the Agency developed costs. The short-technical questionnaire responses did not provide significant intake-level data, outside of intake identification information and velocity. The Agency treated short-technical questionnaire facilities as though they were a single intake with the characteristics reported for the facility. For the detailed questionnaire facilities, the Agency obtained sufficient intake-level information to develop individual costing decisions for each intake.

B1-1.1 Technology Costs

Existing facilities that do not currently comply with the Section 316(b) Phase II Existing Facilities Rule will have to implement technologies to reduce impingement mortality and/or entrainment. The specific technologies vary for the different rule requirements and site-specific situations, but overall these technologies reduce impingement and entrainment (I&E) through implementing design and construction technologies.

For the final rule, each model facility has three potential compliance requirements: (1) no impingement and entrainment controls, (2) impingement controls only, or (3) impingement controls plus entrainment controls. A facility automatically qualifies for compliance requirement (1) if it has recirculating cooling systems in place.

The Agency determined the compliance requirement for each in-scope intake (facility) and compared that requirement against the type of technology already in-place. For the case of entrainment requirements, the intake technologies (outside of recirculating cooling) that qualify to meet the requirements at baseline are fine mesh screen systems, and combinations of far-offshore inlets with passive intakes or fish handling/return systems. A small subset of intakes has entrainment qualifying technologies in-place at baseline. Therefore, in the case of entrainment requirements, most facilities with the requirement will receive technology upgrades. For the case of impingement requirements, there are a variety of intake technologies that qualify to meet the requirements at baseline. The intake types meeting impingement requirements at baseline include the following: barrier net (the only fish diversion system which qualifies), passive intakes (of a variety of types), and fish handling and return systems. A significant number of intakes (facilities) have impingement technologies in place. Therefore, some intakes (facilities) require no technology upgrades when only impingement requirements apply.

For facilities that do not pre-qualify for impingement and/or entrainment technology in-place credits, the Agency analyzed questionnaire data relating to the intake type to determine the particular technology module that would best meet the requirements for the intake.

EPA developed the following costing modules for assessing model-facility compliance costs for today's final rule:

- #1 – Fish handling and return system (impingement only)
- #2 – Fine mesh traveling screens with fish handling and return (impingement & entrainment)
- #3 – New larger intake structure with fine mesh, handling and return (impingement & entrainment)
- #4 – Passive fine mesh screens with 1.75 mm mesh size at shoreline (impingement & entrainment)
- #5 – Fish barrier net (impingement only)
- #6 – Gunderboom (impingement & entrainment)
- #7 – Relocate intake to submerged offshore with passive fine mesh screen with 1.75 mm mesh size (impingement & entrainment)
- #8 – Velocity cap at inlet of offshore submerged (impingement only)
- #9 – Passive fine mesh screen with 1.75 mm mesh size at inlet of offshore submerged (impingement & entrainment)
- #10 – Shoreline tech for submerged offshore (impingement only or I&E)
- #11 – Double-entry, single-exit with fine mesh and fish handling and return (impingement & entrainment)
- #12 – Passive fine mesh screens with 0.75 mm mesh size at shoreline (impingement & entrainment)
- #13 – Relocate intake to submerged offshore with passive fine mesh screen with 0.75 mm mesh size (impingement & entrainment)
- #14 – Passive fine mesh screen at inlet of offshore submerged with 0.75 mm mesh size (impingement & entrainment)

The development and documentation accompanying these costing modules is available in the *Phase II Technical Development Document*.

B1-1.2 Energy Costs

Installation of some of the compliance technologies considered for the final rule will require a one-time, temporary downtime of the plant.

Table B1-1: Estimated Average Downtime for Technology Modules

Module #	Description	Estimated Net Downtime (Weeks)
1	Fish handling and return system	0
2	Fine mesh traveling screens with fish handling and return	0
3	New larger intake structure with fine mesh, handling and return	2 - 4
4	Passive fine mesh screens with 1.75 mm mesh size at shoreline	9 - 11
5	Fish barrier net	0
6	Gunderboom	0
7	Relocate intake to submerged offshore with passive fine mesh screen with 1.75 mm mesh size	9 - 11
8	Velocity cap at inlet of offshore submerged	0
9	Passive fine mesh screen with 1.75 mm mesh size at inlet of offshore submerged	0
10	Shoreline tech for submerged offshore	0
11	Double-entry, single-exit with fine mesh and fish handling and return	0
12	Passive fine mesh screens with 0.75 mm mesh size at shoreline	9 - 11
13	Relocate intake to submerged offshore with passive fine mesh screen with 0.75 mm mesh size	0
14	Passive fine mesh screen at inlet of offshore submerged with 0.75 mm mesh size	9 - 11

Source: U.S. EPA analysis, 2004.

The estimated downtimes are net outages attributable to the changes made to the cooling system in response to the final Phase II rule. EPA assumes that plants would minimize the disruption to their operations by making the required technology upgrades 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 technology upgrades during maintenance periods, facilities could minimize the net impact of their system changes. For the purposes of this analysis, the Agency assumed that the typical scheduled maintenance outages would be four weeks.

❖ *Monetary valuation of downtime*

Technology upgrade downtimes represent a cost to the facilities that incur them. This cost is a loss in revenues offset by a simultaneous reduction in variable production costs (while the plant is out of service, it loses revenues but also does not incur variable costs of production).

EPA estimated facility-specific baseline revenue losses using 2008 revenue projections from the Integrated Planning Model (IPM®). IPM revenues consist of energy revenues and capacity revenues (see discussion of the IPM in Chapter B3). One-time losses due to installation downtime were calculated by dividing each facility's annual revenue projections by 52 and multiplying this value by the estimated average downtime (in weeks) of the facility's compliance technology. For facilities not modeled by the IPM, EPA calculated revenues based on electricity sales for a "typical" operating year for each in-scope facility (using public data from the Energy Information Administration) and the utility-specific wholesale price of electricity. For more detail on this substitute methodology, please refer to Chapter B2 of the EBA as published in support of the proposed Phase II rule.

EPA also used IPM estimates to calculate avoided variable production costs during the downtime, again using facility-specific 2008 projections from the IPM. Variable production cost include both fuel and other variable operating and maintenance costs. Similar to revenues, each facility's annual variable production costs were divided by 52 and multiplied by the facility's estimated average downtime (in weeks). For facilities not modeled by the IPM, EPA used average variable production cost per megawatt hour (MWh) by North American Electric Reliability Council (NERC) region and plant type, calculated from all

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

Phase II facilities modeled by the IPM, and multiplied the facility's generation by the average that corresponds to the facility's NERC region and plant type.[2]

In summary, the average cost of the technology upgrade downtime is the revenue loss during the downtime less the variable expenses that would normally be incurred during that period. The following formulas were used to calculate the net loss due to downtime:

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

where

$$\textit{Variable Production Cost} = \textit{Fuel Cost} + \textit{Variable Operating} \wedge \textit{Maintenance Cost}$$

This approach may overstate the cost of the connection outage because it is based on average annual revenues and variable production costs. If downtime is scheduled during off-peak times, the loss in revenues could be smaller as a result of lower electricity sales and electricity prices.

B1-1.3 Administrative Costs

Compliance with the final Phase II rule requires 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 National Pollution Discharge Elimination System (NPDES) permit application

The final rule requires 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 under the current case-by-case cooling water intake structure permitting procedures, regardless of the final Phase II rule, but are still included in EPA's compliance cost estimate; therefore, the permitting costs of this final rule may be overestimated. 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 a statement of the compliance option selected; developing drawings that show the physical characteristics of the source water; developing a description of the cooling water intake structure (CWIS) configuration and location; developing a facility water balance diagram; developing a narrative of CWIS and cooling water system (CWS) operational characteristics; performing engineering calculations; submitting materials for review by the Director; and keeping records;

In addition, the initial permit renewal application requires a comprehensive demonstration study. The comprehensive demonstration study is a broad set of activities meant to: (1) characterize the source water baseline in the vicinity of the intake structure(s); (2) characterize operation of the cooling water intake(s); and (3) confirm that the technology(ies), operational measures and restoration measures proposed and/or implemented at the CWIS meet the applicable performance standards. The following activities are associated with the comprehensive demonstration study portion of the initial permit application:

- ***proposal for collection of information for comprehensive demonstration study:*** describing historical studies that will be used; describing the proposed and/or implemented technologies, operational measures, and restoration measures to be evaluated; developing a source water sampling plan; submitting data and plans for review; revising plans based on state review; and keeping records;

[2] For a detailed discussion of the NERC regions see Chapter B3, section B3-2.1.c.

- ***source waterbody flow information:*** gathering information to characterize flow (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;

- ***design and construction technology plan:*** delineating hydraulic zone of influence; developing narrative descriptions of technologies; performing engineering calculations; documenting that technologies are optimal; submitting the plan for review; and keeping records;
- ***impingement mortality and entrainment characterization study:*** performing biological sampling; performing impingement and entrainment monitoring; profiling source water biota; identifying critical species; developing a description of additional stresses; developing report based on study results; revising report based on state review; and keeping records;

- ***impingement mortality and entrainment characterization study capital and O&M costs:*** permitting process capital and O&M costs associated with the impingement mortality and entrainment characterization study;

- ***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; submitting data and plan for review; revising plan based on state review; and keeping records.

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 and whether it exceeds capacity utilization rate and proportional flow thresholds. Certain activities are expected to be more costly for marine and Great Lakes facilities than for freshwater facilities. Some activities apply to all facilities, while other activities apply only if the facility exceeds the capacity utilization rate or proportional flow thresholds. Facilities that have recirculating systems in the baseline, and facilities that already have or are required to install wedgewire screens, will only have a few required activities. The maximum initial permitting cost for a facility that carries out all of the described activities is estimated to be approximately $1.0 million.

Table B1-2: Cost of Initial Post-Promulgation NPDES Permit Application Activities ($2002)

Activity	Estimated Maximum Cost per Permit				
	Freshwater River/ Stream	Lake	Great Lake	Estuary/ Tidal River	Ocean
Start-up activities[b]	$2,297	$2,297	$2,297	$2,297	$2,297
Permit application activities[a]	$11,105	$11,105	$11,105	$11,105	$11,105
Proposal for collection of information for comprehensive demonstration study[b]	$13,740	$13,740	$13,740	$13,740	$13,740
Source waterbody flow information[a]	$3,768	$4,370	$0	$0	$0
Design and construction technology plan[a]	$6,751	$4,875	$6,751	$6,751	$6,751
Impingement mortality and entrainment characterization study[c]	$442,474	$442,474	$811,401	$811,401	$811,401
Impingement mortality and entrainment characterization study capital and O&M costs[c]	$78,000	$78,000	$152,100	$152,100	$152,100
Verification monitoring plan[a]	$6,667	$6,667	$6,667	$6,667	$6,667
Total Initial Post-Promulgation NPDES Permit Application Cost	**$564,802**	**$563,528**	**$1,004,061**	**$1,004,061**	**$1,004,061**

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

Source: U.S. EPA, 2004a.

Another potential cost associated with the initial NPDES permit is pilot studies of compliance technologies. Facilities carry out pilot studies to determine if the compliance technology will function properly when installed and operated. EPA assumes that facilities with technology installation costs of greater than $500,000 will conduct pilot studies, and that these studies will cost either $150,000 or ten percent of technology installation costs, whichever is greater. EPA estimates that approximately 15 percent of Phase II facilities will incur these costs. Activities associated with pilot studies include:

- ***deploying the pilot technology:*** installing an intake pipe separate from the facility's actual cooling water system, but in the vicinity of the operating CWIS; installing the proposed technology to feed into the separate intake pipe; and pumping water through the intake pipe under various pumping scenarios and seasonal conditions;

- ***monitoring efforts:*** collecting five samples over a twenty-four hour period, every two weeks for six months;

- ***evaluation of data:*** analyzing the data; summarizing the results; and using this information to evaluate the effectiveness of the technology.

In addition to the activities described above, some facilities are expected to conduct a site-specific determination of Best Technology Available (BTA). Since activities associated with site-specific determinations are voluntary and would only be conducted if the facilities expected them to be less expensive than complying with the Phase II requirements, EPA did not include site-specific determination costs in its compliance cost estimates. The initial permitting activities associated with site-specific determinations are:

- ***information to support site-specific determination of BTA:*** performing a comprehensive cost evaluation study; developing valuation of monetized benefits of reducing impingement and entrainment; evaluating detailed mortality data; performing engineering calculations and drawings; submitting results for review; and keeping records; and

- ***site-specific technology plan:*** describing selected technologies, operational measures, and restoration measures; documenting that technologies, operational measures, or restoration measures are optimal; performing design calculations and preparing drawings and estimates; performing engineering calculations, including estimates of the efficacy of the proposed and/or implemented technologies, operational measures, or restauration measures; submitting results for review; and keeping records.

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 required for the initial permit renewal application. EPA expects that facilities can use some of the information from the initial permit application. 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 and whether it exceeds the capacity utilization rate and proportional flow thresholds. 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 repermitting cost for a facility that carries out all of the described activities is estimated to be approximately $340,900.

Table B1-3: Cost of NPDES Repermit Application Activities ($2002)[a]

Activity	Estimated Maximum Cost per Permit				
	Freshwater River/ Stream	Lake	Great Lake	Estuary/ Tidal River	Ocean
Start-up activities	$770	$770	$770	$770	$770
Permit application activities	$6,875	$6,875	$6,875	$6,875	$6,875
Proposal for collection of information for comprehensive demonstration study	$3,816	$3,816	$3,816	$3,816	$3,816
Source waterbody flow information	$1,170	$1,351	$0	$0	$0
Design and construction technology plan	$3,459	$2,483	$3,459	$3,459	$3,459
Impingement mortality and entrainment characterization study	$143,613	$143,613	$265,147	$265,147	$265,147
Impingement mortality and entrainment characterization study capital and O&M costs	$31,200	$31,200	$60,840	$60,840	$60,840
Total NPDES Repermit Application Cost	**$190,904**	**$190,108**	**$340,907**	**$340,907**	**$340,907**

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

Source: U.S. EPA, 2004a.

c. Monitoring, record keeping, and reporting

Monitoring, record keeping, and reporting activities and costs include:

- ***biological monitoring for impingement:*** collecting monthly samples for at least two years after the initial permit issuance; analyzing samples; performing statistical analyses; and keeping records;

- ***biological monitoring for entrainment:*** collecting biweekly samples during the primary period of reproduction, larval recruitment, and peak abundance for at least two years after the initial permit issuance; handling and preparing samples; performing statistical analyses, and keeping records;

- ***entrainment sampling capital and O&M costs:*** contract laboratory analysis of entrainment samples;

- ***verification study:*** conducting technology performance monitoring; performing statistical analyses; submitting monitoring results and study analysis; and keeping records;

- ***yearly status report activities:*** reporting on inspection and maintenance activities; detailing biological monitoring results; 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 are estimated to incur for its monitoring, record keeping, and reporting activities is approximately $99,900.

Table B1-4: Cost of Annual Monitoring, Record Keeping, and Reporting Activities ($2002)

Activity	Estimated Cost				
	Freshwater River/ Stream	Lake	Great Lake	Estuary/ Tidal River	Ocean
Biological monitoring for impingement	$19,227	$19,227	$24,487	$24,487	$24,487
Biological monitoring for entrainment	$31,724	$31,724	$39,667	$39,667	$39,667
Entrainment sampling capital and O&M costs	$7,800	$7,800	$10,140	$10,140	$10,140
Verification study	$7,457	$7,457	$7,457	$7,457	$7,457
Yearly status report activities	$18,152	$18,152	$18,152	$18,152	$18,152
Total Monitoring, Record Keeping, and Reporting Cost	**$84,361**	**$84,361**	**$99,904**	**$99,904**	**$99,904**

Source: U.S. EPA, 2004a.

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) a high concentration of facilities estimated to be out of service as a result of technology upgrade downtimes in the same region and at the same time could lead to temporary energy effects in that region.

For this analysis, it was assumed that facilities have to come into compliance with the final Phase II rule during the year their first post-promulgation NPDES permit is issued. Since NPDES permits are renewed every five years, all facilities are estimated to come into compliance between 2005 and 2009.[3] Table B1-5 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

[3] Note that this assumption was made for this analysis only. EPA estimates that, in reality, compliance will begin in 2008.

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

NERC Region	2005	2006	2007	2008	2009	Total
ASCC	1	0	0	0	0	**1**
ECAR	16	23	29	22	12	**102**
ERCOT	11	7	4	14	15	**51**
FRCC	10	3	1	8	8	**30**
HI	0	0	0	0	3	**3**
MAAC	11	11	11	8	4	**45**
MAIN	15	13	7	8	10	**53**
MAPP	7	7	11	15	4	**44**
NPCC	15	15	11	12	8	**61**
SERC	16	20	25	20	15	**96**
SPP	10	5	4	8	5	**32**
WSCC	14	7	4	3	6	**35**
Total	**126**	**111**	**107**	**119**	**91**	**554**

[a] Note that compliance years were estimated for this analysis. Actual compliance years might be different than stated in this table.

Source: U.S. EPA analysis, 2004.

B1-3 Total Private Compliance Costs

EPA estimated the total private pre-tax compliance costs for the final 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 July 2001 dollars and converted to year-2002 dollars using the construction cost index (CCI). Administrative costs were developed in 2002 dollars.

B1-3.1 Methodology

The private cost of the Phase II rule represents the total compliance costs of the 554 in-scope section 316(b) Phase II facilities. For this analysis, EPA assumed that facilities will comply over a five-year period between 2005 and 2009. 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 Federal and State corporate income tax rates to privately-owned facilities (U.S. Department of the Treasury, 2002; FTA, 2003). 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:

- ***Capital Costs:*** This cost is incurred in the year that the facility's first post-promulgation permit is issued.

- ***Cost of Connection Outage:*** EPA estimates that the average outage to construct and install the various compliance technologies ranges from zero to 11 weeks. 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 technology.

- ***Impingement Mortality and Entrainment Characterization Study:*** This is a three-year study required for all facilities except those who already have recirculating systems in the baseline and those who already have or are installing a wedgewire screen. The cost of this study is incurred over the three years preceding the facility's first post-promulgation permit.

The following formula was used to calculate the net present value of the one-time costs as of 2004:[4]

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

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 (2005 to 2009)

b. Annualization of compliance costs

Annualized compliance costs include all capital costs, O&M costs, administrative costs, and plant outage costs of compliance with the final Phase II rule. To derive the constant annual value of the capital costs and the value of the technology construction and/or connection plant downtime, EPA annualized them over the component's useful life, using a seven percent discount rate. 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; the connection downtime and initial permitting costs were annualized over 30 years; the repermitting costs were annualized over 5 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 connection downtime and initial permitting costs; 10 years for flow reduction and I&E technologies; 5 years for repermitting costs)

EPA then added the annualized capital, downtime, and permitting costs to annual O&M and administrative costs to derive each facility's total annual cost of complying with the final 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:

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

[4] Calculation of the present value assumes that the cost is incurred at the beginning 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.[5] A reduction in tax liability was only applied to privately-owned facilities (government-owned entities and cooperatives are not subject to income taxes).

B1-3.2 Total Private Costs of the Final Rule

EPA estimates that the 554 in-scope facilities will incur annual costs of complying with the final Phase II rule of $385 million on a pre-tax basis and $250 million on a post-tax basis. Table B1-6 presents annualized facility compliance costs by cost category and steam plant type. Costs are presented on a pre-tax and post-tax basis. The annual pre-tax compliance costs range from approximately $6.6 million for other steam facilities to $185 million for coal steam facilities. The annual post-tax compliance costs range from approximately $4.0 million for other steam facilities to $122 million for coal steam facilities.

Table B1-6: Private Annualized Compliance Costs by Plant Type (in millions, $2002)

Plant Type	One-Time Costs				Recurring Costs			Total
	Capital Technology	Connection Outage	Initial Permit Application	Pilot Study	O&M	Monitoring, Record Keeping & Reporting	Permit Renewal	
Pre-Tax Compliance Costs								
Coal Steam	$87.2	$26.3	$12.7	$1.1	$24.3	$24.2	$8.9	**$184.7**
Combined Cycle	$5.5	$0.3	$0.7	$0.1	$0.6	$1.4	$0.5	**$9.0**
Nuclear	$57.1	$21.4	$2.3	$1.1	$2.9	$4.9	$1.7	**$91.4**
O/G Steam	$43.5	$3.8	$9.1	$0.8	$15.5	$14.2	$6.5	**$93.4**
Other Steam	$3.0	$0.5	$0.6	$0.1	$1.2	$0.7	$0.4	**$6.6**
Total	**$196.2**	**$52.3**	**$25.4**	**$3.2**	**$44.4**	**$45.6**	**$18.2**	**$385.1**
Post-Tax Compliance Costs								
Coal Steam	$56.4	$17.0	$8.6	$0.7	$16.6	$16.5	$6.1	**$122.1**
Combined Cycle	$3.4	$0.2	$0.5	$0.0	$0.4	$1.0	$0.4	**$5.8**
Nuclear	$34.9	$12.8	$1.5	$0.7	$2.1	$3.1	$1.1	**$56.2**
O/G Steam	$27.9	$2.3	$6.1	$0.5	$10.8	$9.6	$4.3	**$61.5**
Other Steam	$1.8	$0.3	$0.4	$0.1	$0.7	$0.4	$0.3	**$4.0**
Total	**$124.5**	**$32.6**	**$17.0**	**$2.0**	**$30.6**	**$30.7**	**$12.2**	**$249.5**

Source: U.S. EPA analysis, 2004.

B1-4 Uncertainties and Limitations

EPA's estimates of the compliance costs associated with the final 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 Detailed Questionnaire (DQ) and Short Technical Questionnaire (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

[5] 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.

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 connection outage. EPA's analysis used projected future information on electricity generation, electricity prices, and variable production 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 final 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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Chapter B2: Cost Impact Analysis

INTRODUCTION

CHAPTER CONTENTS

This chapter presents an assessment of the magnitude of compliance costs associated with implementing the Final Section 316(b) Phase II Existing Facilities Rule, including a cost-to-revenue analysis at the facility and firm levels, an analysis of compliance costs per household at the North American Electric Reliability Council (NERC) level, and an analysis of compliance costs relative to electricity price projections, also at the NERC level.[1] Later chapters consider the potential energy effects of the final 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*).

B2-1 COST-TO-REVENUE MEASURE

The "cost-to-revenue measure" is used to assess the magnitude of compliance costs relative to revenues. 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.

Annualized compliance costs include all capital costs, operating and maintenance (O&M) costs, administrative costs, and plant outage costs of compliance with the final Phase II rule. To derive the constant annual value of the technology capital costs, the initial permitting cost, and the value of construction and/or connection plant outage, EPA annualized them over 10 or 30 years, using a seven percent discount rate. EPA then added the annualized capital and connection outage costs to annual O&M costs, and administrative costs to derive each facility's total annual cost of complying with the final 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* (U.S. EPA, 2004).

EPA compared the annualized compliance costs to the estimated facility and firm revenues. This analysis uses impact thresholds of 1.0 and 3.0 percent.

B2-1.1 Facility Analysis

EPA compared the annualized post-tax compliance costs of the final rule as a percentage of annual revenues for each of the 543 surveyed in-scope facilities. EPA used facility-specific baseline revenue projections from ICF Consulting's Integrated Planning Model (IPM®) for 2008 for this analysis. The IPM did not provide revenues for 16 facilities. Eight of these facilities are estimated to be baseline closures and another eight facilities are not modeled by the IPM. In addition, five facilities are projected by IPM to have zero revenues in the baseline. 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

[1] It should be noted that these 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 final 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: Summary of Compliance Costs*. 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 (for this analysis, assumed to be 2005 to 2009).

ratio for the 13 non-baseline closure facilities with missing information. EPA then applied sample weights to the 543 facilities to account for non-sampled facilities and facilities that did not respond to the survey.

Table B2-1 below presents the results of the facility-level cost-to-revenue measure conducted for the 554 electric generating facilities subject to the final 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, greater than three percent, and the number of facilities estimated to be baseline closures; 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		
By Ownership Type								
Investor-Owned Utility	274	179	52	27	15	1	0.01%	81.7%
Nonutility	179	94	36	35	8	6	0.01%	12.2%
Federal Utility	14	12	1	1	0	0	0.05%	1.9%
State-Owned Utility	7	3	1	1	2	0	0.03%	3.8%
Municipality	48	14	4	20	10	0	0.03%	63.3%
Political Subdivision	7	4	0	1	1	1	0.05%	19.0%
Rural Electric Cooperative	25	8	5	9	3	0	0.03%	8.9%
Total[a]	**554**	**314**	**99**	**94**	**39**	**8**	**0.01%**	**81.7%**
By Fuel Type								
Coal	302	189	67	38	8	0	0.01%	21.1%
Combined-Cycle	17	10	3	2	2	0	0.01%	5.6%
Nuclear	59	43	1	6	2	7	0.01%	4.3%
Oil and Gas Steam	168	72	28	41	25	1	0.02%	81.7%
Other Steam	8	0	0	7	1	0	1.20%	4.0%
Total[a]	**554**	**314**	**99**	**94**	**39**	**8**	**1.20%**	**81.7%**

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

Source: IPM analysis: model run for Section 316(b) base case, 2008, EPA electricity demand assumptions; U.S. EPA analysis, 2004.

Table B2-1 shows that the vast majority of facilities subject to the final Phase II rule incur low compliance costs when compared to facility-level revenues. Out of the 554 facilities subject to the final Phase II rule, 413, or approximately 75 percent, incur annualized costs of less than 1.0 percent of revenues. Of these, 314, or approximately 57 percent, incur annualized costs of less than 0.5 percent of revenues. Ninety-four facilities, or 17 percent are estimated to incur costs of between 1.0 and 3.0 percent of revenues, and 39 facilities, or 7 percent, are estimated to incur costs of greater than 3.0 percent. Eight facilities are estimated to be baseline closures.

An investor-owned facility is estimated to experience the highest compliance cost compared to projected revenues, 81.7 percent. In addition, investor-owned utilities are the group with the highest number of facilities (15) with a cost-to-revenue ratio greater than 3.0. However, State-owned utilities have the highest percentage of facilities with a cost-to-revenue ratio greater than 3.0, two out of seven, or 29 percent. By fuel type, oil and gas steam electric generators experience the greatest incidence of compliance costs to revenues: 25 of 168 facilities, or 14.9 percent, are estimated to have a cost-to-revenue ratio of greater than 3.0 percent.

B2-1.2 Firm Analysis

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

EPA first identified the domestic parent entity of each in-scope Phase II facility (for a detailed description of this analysis, see *Chapter B4: Regulatory Flexibility Analysis*). From this analysis, EPA determined that 126 unique domestic parent entities own the facilities subject to the final Phase II regulation. EPA obtained the sales revenues for the 126 domestic parent entities from publicly available data sources (the 1999, 2000, and 2001 Forms EIA-861; the Dun and Bradstreet database; company 10-K filings; and entities' websites). The firm-level analysis is based on the ratio of the aggregated post-tax compliance costs for each facility owned by the 126 parent entities to the firm's total sales revenue. EPA identified 71 entities, out of the 126 unique domestic parent entities, that own more than one facility subject to the final Phase II rule.

Table B2-2 below summarizes the results of the cost-to-revenue measure conducted for the 126 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%		
Investor-Owned Utility	274	41	39	2	0	0	0.00%	0.6%
Nonutility	179	26	25	1	0	0	0.01%	0.8%
Federal Utility	14	1	1	0	0	0	0.17%	0.2%
State-Owned Utility	7	4	4	0	0	0	0.04%	0.3%
Municipality	48	36	20	6	9	1	0.03%	6.7%
Political Subdivision	7	3	2	0	1	0	0.09%	1.0%
Rural Electric Cooperative	25	15	14	1	0	0	0.12%	0.6%
Total[a]	**554**	**126**	**105**	**10**	**10**	**1**	**0.00%**	**6.7%**

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

Source: U.S. EPA analysis, 2004.

EPA estimates that the compliance costs will comprise a very low percentage of firm-level revenues. Of the 126 parent entities with facilities subject to the final Phase II rule, 115, or approximately 91 percent, incur annualized costs of less than 1.0 percent of revenues. Of these, 105, or approximately 83 percent, incur annualized costs of less than 0.5 percent of revenues. Ten entities incur costs of between 1.0 and 3.0 percent of revenues and only one entity incurs costs of greater than 3.0 percent. EPA estimates that one entity only owns an in-scope facility, which is projected to be a baseline closure. The compliance cost incurred by this entity is less than 0.5 percent of revenues. Overall, the estimated annualized compliance costs represent between less than 0.01 and 6.7 percent of the entities' annual sales revenue.

At the firm level, municipalities are estimated to experience the highest cost-to-revenue ratios. Ten out of eleven firms with ratios of greater than 1.0 percent are municipalities. In addition, municipalities experience the highest cost-to-revenue ratio of all parent types, 6.7 percent.

B2-2 COST PER HOUSEHOLD

EPA also conducted an analysis that evaluates the potential cost per household, if Phase II facilities were able to pass compliance costs on to their customers.[3] This analysis estimates the average compliance cost per household for each North American Electric Reliability Council (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.[4] 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 2001 Form EIA-861 database. Utility-level sales were aggregated by NERC region to derive each region's total electricity sales in 2001. In addition, EPA aggregated the national pre-tax compliance costs by the NERC region in which the 554 Phase II facilities are located. The average compliance cost per MWh of electricity sales is calculated by dividing total pre-tax compliance costs by total electricity sales 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 final 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. This analysis also assumes that there will be no reduction in electricity consumption by the consumers in response to price increases.

Table B2-3 shows the results of this analysis: the estimated cost per residential consumer ranges from $0.50 per year in Alaska (ASCC) to $8.18 per year in Hawaii (HI). The U.S. average cost per residential household is $1.21 per year.

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[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.

[4] For a detailed discussion of NERC regions see Chapter A3, *Profile of the Electric Power Industry*, section A3-2.3.

Table B2-3: Annual Compliance Cost per Residential Consumer by NERC Region in 2001

NERC Region [a]	Total National Pre-Tax Compliance Cost	Total Electricity Sales (MWh)	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	$337,442	5,427,689	$0.06	1,891,468	234,646	8.06	$0.50
ECAR	$76,413,402	504,256,959	$0.15	161,442,646	15,698,205	10.28	$1.56
ERCOT	$20,921,310	280,585,786	$0.07	105,198,123	7,309,073	14.39	$1.07
FRCC	$27,281,223	186,616,722	$0.15	94,834,627	6,885,280	13.77	$2.01
HI	$10,095,493	9,370,360	$1.08	2,665,168	351,229	7.59	$8.18
MAAC	$39,826,208	235,576,827	$0.17	82,687,782	8,921,106	9.27	$1.57
MAIN	$31,880,030	257,913,569	$0.12	75,925,257	8,366,132	9.08	$1.12
MAPP	$11,833,570	139,610,505	$0.08	49,125,931	4,933,221	9.96	$0.84
NPCC	$54,991,490	253,142,223	$0.22	87,587,585	12,676,283	6.91	$1.50
SERC	$63,409,419	748,160,887	$0.08	278,450,252	20,550,922	13.55	$1.15
SPP	$11,291,028	172,750,800	$0.07	60,173,420	5,002,020	12.03	$0.79
WSCC	$36,821,337	571,981,463	$0.06	200,686,234	23,085,962	8.69	$0.56
U.S.	**$385,101,952**	**3,365,393,790**	**$0.11**	**1,200,668,493**	**114,014,079**	**10.53**	**$1.21**

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, 2001; U.S. EPA analysis, 2004.

B2-3 Electricity Price Analysis

EPA also considered potential effects of the final 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 final rule; (2) total electricity sales, based on the Annual Energy Outlook (AEO) 2003; and (3) prices by consumer type (residential, commercial, industrial, and transportation), also from the AEO 2003. All three data elements were calculated by NERC region.[5]

Table B2-4 shows the annualized costs of complying with the final 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 0.007 cents per KWh sales in SPP to 0.019 cents per KWh sales in NPCC. The U.S. average is estimated to be 0.011 cents per KWh sales.

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

NERC Region	Annualized Pre-Tax Compliance Costs (National; $2002)	Total Electricity Sales (MWh; 2001)	Annualized Pre-Tax Compliance Cost (Cents / KWh Sales)
ASCC	$337,442	---	---
ECAR	$76,413,402	508,632,996	¢0.015
ERCOT	$20,921,310	269,572,052	¢0.008
FRCC	$27,281,223	186,505,005	¢0.015
HI	$10,095,493	---	---
MAAC	$39,826,208	243,576,004	¢0.016
MAIN	$31,880,030	231,183,029	¢0.014
MAPP	$11,833,570	150,737,030	¢0.008
NPCC	$54,991,490	282,686,981	¢0.019
SERC	$63,409,419	756,352,051	¢0.008
SPP	$11,291,028	167,893,982	¢0.007
WSCC	$36,821,337	223,035,996	¢0.017
U.S.	**$385,101,952**	**3,397,995,361**	**¢0.011**

Source: U.S. DOE, 2003; U.S. EPA analysis, 2004.

To determine potential effects on electricity prices as a result of the final 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 increases by consumer type that are estimated to result from the final Phase II rule. The largest potential increase in electricity prices is 0.49 percent (¢0.017 / ¢3.39) for an industrial facility in WSCC. The average increase in electricity prices is only estimated to be between 0.13 percent (¢0.011 / ¢8.58) for households and 0.24 percent (¢0.011 / ¢4.77) for industrial customers.

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.

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

Table B2-5: Estimated Price Increase as a Percent of 2001 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	¢0.015	¢7.54	0.20%	¢6.54	0.23%	¢4.17	0.36%	¢6.16	0.24%	¢5.92	0.25%
ERCOT	¢0.008	¢8.15	0.10%	¢7.67	0.10%	¢4.57	0.17%	¢7.10	0.11%	¢6.94	0.11%
FRCC	¢0.015	¢8.68	0.17%	¢7.14	0.20%	¢5.39	0.27%	¢7.70	0.19%	¢7.80	0.19%
MAAC	¢0.016	¢9.09	0.18%	¢7.75	0.21%	¢6.32	0.26%	¢7.88	0.21%	¢7.92	0.21%
MAIN	¢0.014	¢7.79	0.18%	¢6.58	0.21%	¢4.28	0.32%	¢6.45	0.21%	¢6.24	0.22%
MAPP	¢0.008	¢7.07	0.11%	¢5.95	0.13%	¢3.99	0.20%	¢5.93	0.13%	¢5.60	0.14%
NPCC	¢0.019	¢12.98	0.15%	¢10.45	0.19%	¢6.56	0.30%	¢10.48	0.19%	¢10.57	0.18%
SERC	¢0.008	¢7.70	0.11%	¢6.67	0.13%	¢4.23	0.20%	¢6.64	0.13%	¢6.27	0.13%
SPP	¢0.007	¢7.58	0.09%	¢6.38	0.11%	¢4.15	0.16%	¢6.04	0.11%	¢6.18	0.11%
WSCC	¢0.017	¢6.50	0.25%	¢6.15	0.27%	¢3.39	0.49%	¢5.93	0.28%	¢5.28	0.31%
U.S.	**¢0.011**	**¢8.58**	**0.13%**	**¢7.85**	**0.14%**	**¢4.77**	**0.24%**	**¢7.39**	**0.15%**	**¢7.21**	**0.16%**

[a] Prices are in cents per KWh.

Source: U.S. EPA analysis, 2004.

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Chapter B3: Electricity Market Model Analysis

INTRODUCTION

The Final Section 316(b) Phase II Existing Facilities Rule applies to a subset of facilities within the electric power generation industry. However, due to interdependencies within the electric power market, direct 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 capacity utilization, generation, and profitability. 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 of electricity and the construction of new generating capacity.

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EPA used ICF Consulting's Integrated Planning Model (IPM®), an integrated energy market model, to conduct the economic analyses supporting the Final 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 final 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");[1] and (2) potential economic impacts on in-scope facilities.

The final rule was evaluated under two electricity demand growth assumptions: The first scenario uses EPA's electricity demand assumptions. Under this scenario, demand for electricity is based on the Annual Energy Outlook (AEO) 2001 forecast adjusted to account for efficiency improvements not factored into AEO's projections of electricity sales. The second scenario uses the unadjusted electricity demand from the AEO 2001. Section B3-4 presents the results of the IPM analysis for the final rule under EPA's assumptions. Appendix A presents the results of the IPM analysis for the final rule under the unadjusted AEO assumptions. The appendix also presents a comparison of the results under the two alternative scenarios.

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 professionals, EPA identified three potential models and considered each for the analyses in support of the 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.[2]

[1] Please refer to Section B6-7 for a discussion of this analysis.

[2] 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.

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 suited for the analysis of section 316(b) regulatory options. Modeling criteria refer to the models' technical capabilities that are required to provide the outputs necessary for the analysis of the section 316(b) regulation. 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 Phase II regulation 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 section 316(b) regulation 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 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.[3] 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 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).

[3] 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.

When the analyses in support of the Phase II proposal and Notice of Data Availability (NODA) were developed, the latest EPA specification of the U.S. power market, "EPA Base Case 2000," was based on IPM Version 2.1. In July 2003 a new version of the model, Version 2.1.6, was released. However, the tight promulgation schedule made it impossible for EPA to switch to the newer version for the analyses in support of this final rule. The analyses presented in this chapter, and the appendix, are therefore based on the specifications for the EPA Base Case 2000.

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.

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.

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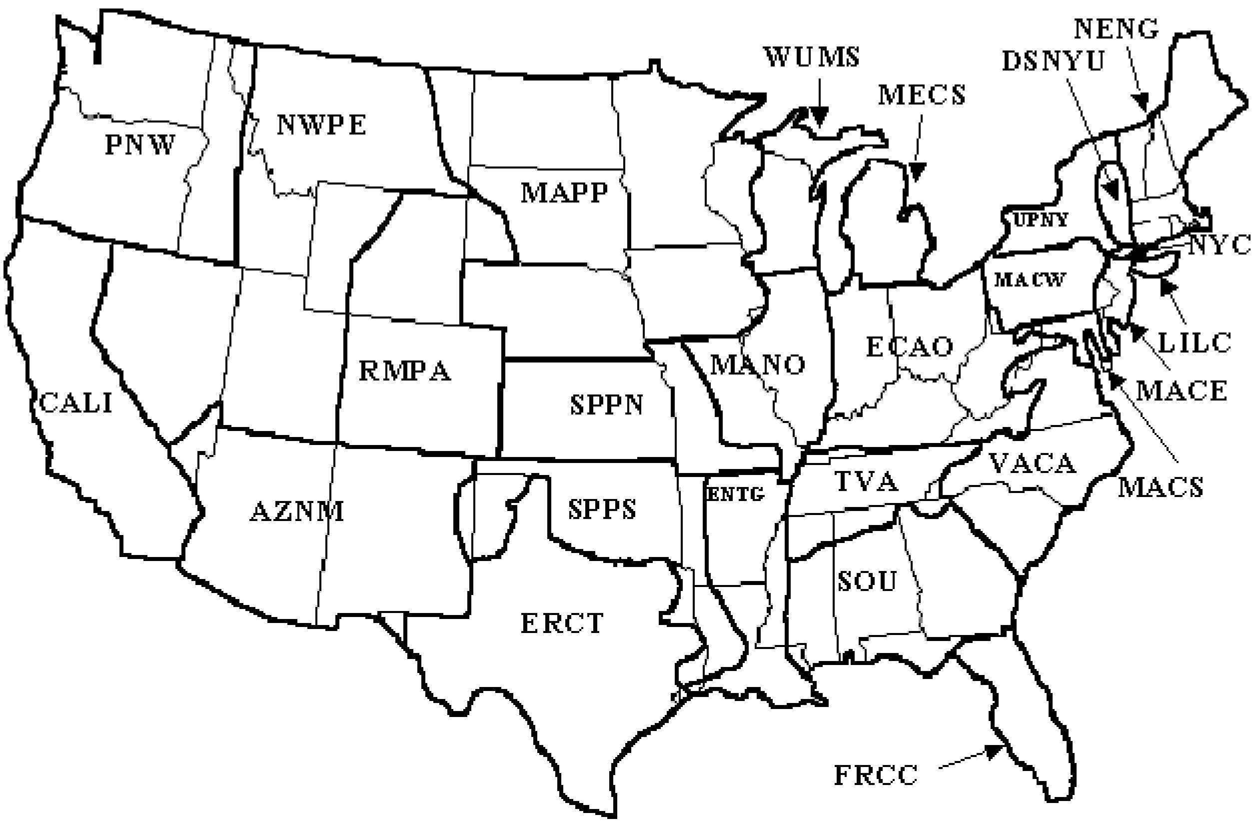
[4] EPA used the IPM to forecast operational changes, including changes in capacity, generation, revenues, electricity prices, and plant closures, resulting from the rule. In other policy analyses, the IPM is generally also used to determine the compliance response for each model facility. This process 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 in impingement and entrainment 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.

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.[5] The model run years were selected before the analysis in support of the proposed Phase II rule for the following reasons:

- **2008** was selected based on the assumption that all in-scope facilities would be required to comply with the requirements of the Phase II rule during the first five years after promulgation (at the time of proposal, promulgation was scheduled for August 28, 2003 so that the compliance window would have been 2004 to 2008). Therefore, in 2008, all facilities would have been in compliance, and 2008 would have represented the post-compliance state of the industry.

- **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 at proposal) would have to comply by the end of the permit term of the first permit issued after promulgation (at the time, this was 2004 to 2012). As installation of a cooling tower may require the temporary shut-down of the facility, 2013 would have represented the first full, post-compliance year for options requiring cooling towers.

- **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.

With the change in promulgation date from August 28, 2003 to February, 2004, EPA revised its assumptions of when facilities are likely to come into compliance with the Phase II rule from 2004-2008 to 2005-2009 (because start-up activities are required for compliance with the Phase II rule, it will no longer be possible to comply in 2004).[6] However, changing run

[5] 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 2026 was not used in this analysis.

[6] Note that compliance years 2005 to 2009 are an assumption for this analysis. The "real" compliance schedule might be different.

years requires significant structural changes to the IPM. EPA therefore decided not to change the model run years selected at proposal for this analysis. EPA mainly relied on data for 2010 in the analyses of the final rule (presented in this chapter).

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 Phase II regulatory options, and the calendar years mapped to each.

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) NODA Base Case.

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

The analysis of the Final Phase II Rule (and the other regulatory options analyzed at proposal and for the NODA) 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. For the NODA and final rule analyses, EPA also disaggregated non-steam generators at Phase II facilities and generators at facilities subject to the upcoming Phase III regulation. This change increased the total number of model plants from 1,777 to 2,096.

- ***Use of Different Model Run Years:*** The original specification of the IPM's EPA Base Case 2000 uses five model run years chosen based on the requirements of various air policy analyses: 2005, 2010, 2015, 2020, and 2026. As explained above, EPA was interested in analyzing different years for the section 316(b) Phase II rule. Therefore, EPA changed the 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) NODA 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 do not change in 2010 and are lower by 0.1% in 2020.
- Early retirements of base case oil and gas steam capacity under the section 316(b) specifications are lower by 850 megawatt (MW). Early retirements of base case nuclear capacity decreased by 480 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 use and a 1.5 percent reduction in gas fuel use in 2010.

The IPM base case specification for the final rule is the same as the one used for the section 316(b) Phase II NODA.

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 535 facilities subject to Phase II regulation and modeled by the IPM.[7] For each facility, compliance costs consist of capital costs (including costs for new screens or fish barrier nets, intake relocation, and intake piping modification), fixed O&M costs, variable O&M costs, permitting costs, and capacity reductions (for information on the costing methodology, see the Section 316(b) Technical Development Document; U.S. EPA, 2004).

- ***Capital cost*** inputs into the IPM are expressed as a fixed O&M cost, in dollars per kilowatt (KW) of capacity per year. The capital costs of compliance reflect the up-front cost of construction, equipment, and capital associated with the installation of required compliance technologies. The IPM uses two up-front cost values as model inputs (one each for technologies with a useful life of 10 and 30 years, respectively) and translates these values into a series of annual post-tax 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 for initial permitting costs and 10 years for the various compliance technologies) or the years remaining in the modeling horizon, whichever is shorter.[8]

- ***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 megawatt hour (MWh) of generation.

[7] Of the 543 surveyed facilities subject to the section 316(b) Phase II rule, eight are not modeled in the IPM. Three facilities are in Hawaii and one is in Alaska. Neither state is represented in the IPM. Four facilities are on-site generators that do not provide electricity to the grid.

[8] 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.

- ***Permitting costs*** consist of initial permitting costs, annual monitoring costs, repermitting costs (occurring every five years after issuance of the initial permit), and, for some facilities, pilot study costs. Permitting cost inputs are expressed as follows: initial permitting and pilot study activities are necessary for the on-going operation of the plant and are therefore added to the capital costs for technologies with a 30-year useful life; annual monitoring and annualized repermitting costs are added to the fixed O&M costs.

- ***Capacity reductions*** consist of a one-time generator downtime. Generator downtime estimates reflect the amount of time generators are off-line while compliance technologies are constructed and/or installed and are expressed in weeks. The generator downtime is a one-time event that affects several of the compliance technologies evaluated by EPA. Generator downtime is estimated to occur during the year when a facility complies with the policy option. Since the years that are mapped into a run year are assumed to have the same characteristics as the run year itself, generator downtimes were applied as an average over the years that are mapped into each model run year.[9] Estimated generator downtimes due to construction and/or installation range from two to eleven weeks (see also Chapter B1, Table B1-1).

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 535 modeled section 316(b) facilities were identified using data from the IPM.

- 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 design intake flow data, this distribution was based on each generator's proportion of total design intake volume; for facilities without available design 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]

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[9] For example, a facility with a downtime in 2008 was modeled as if 1/5th of its downtime occurred in each year between 2005 and 2009. A potential drawback of this approach of averaging downtimes over the mapped years is that the snapshot of the effect of downtimes during the model run year is the average effect; this approach does not model potential worst case effects of above-average amounts of capacity being down in any one NERC region during any one year.

[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 100 MW. Generator-level design intake flow data were not available for 57 of the 535 modeled facilities.

[11] Repowering in the IPM consists of converting oil/gas or coal capacity to combined-cycle capacity. The modeling assumption is that each one MW of existing capacity is replaced by two MW of repowered 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 final rule and other regulatory alternatives. 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.

- ***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 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.

- ***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 cost 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. In post-compliance scenarios, fixed O&M costs also include annualized capital costs of compliance and permitting costs.

- ***Capital Costs*** – The cost of construction, equipment, and capital. Capital costs are associated with investment in new equipment, e.g., the replacement of a boiler or condenser, installation of technologies to meet the requirements of air regulations, or the repowering of a plant.

B3-3 Economic Impact Analysis Methodology

The outputs presented in the previous section were used to identify changes to economic and operational characteristics such as capacity, generation, revenue, cost of generation, and electricity prices associated with Phase II regulatory options. EPA developed impact measures at two analytic levels: (1) the market as a whole, including all facilities 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 (i.e., the model run in the absence of section 316(b) Phase II regulations) and the post-compliance scenario. The following subsections describe the impact measures used for the two levels of analysis.

[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.

B3-3.1 Market-level Impact Measures

The market-level analysis evaluates regional changes as a result of Phase II 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 partial or full closures of plants subject to the rule. In the short term, temporary plant shut-downs for the installation of Phase II compliance technologies may lead to reductions in available capacity.[13] When analyzing changes in available capacity, EPA distinguished between **existing capacity**, **new capacity additions**, and **repowering additions**. Under this measure, EPA also analyzed capacity **closures**. Only capacity that is projected to remain operational in the base case but is closed in the post-compliance case is 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 unit or plant that would close in the base case but operates in the post-compliance case.

- ***(2) Changes in the price of electricity:*** This measure considers changes in regional prices as a result of Phase II regulation. 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 Phase II compliance technologies. This analysis considers changes in both **energy prices** and **capacity prices**.

- ***(3) 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 or a change in the amount of electricity traded between regions. In the short term, temporary plant shut-downs to install Phase II compliance technologies 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.

- ***(4) Changes in revenues:*** This measure considers the revenues realized by all facilities in the market and includes both energy revenues and capacity revenues (see definition in section B3-2.4 above). A change in revenues could be the result of a change in generation and/or the price of electricity.

- ***(5) Changes in costs:*** This measure considers changes in the overall cost of generating electricity, including fuel costs, variable and fixed O&M costs, and capital costs. **Fuel costs** and **variable O&M costs** are production costs that vary with the level of generation. Fuel costs generally account for the single largest share of production costs. **Fixed O&M costs** and **capital costs** do not vary with generation. They are fixed in the short-term and therefore do not affect the dispatch decision of a unit (given sufficient demand, a unit will dispatch as long as the price of electricity is at least equal to its per MWh production costs). However, in the long-run, these costs need to be recovered for a unit to remain economically viable.

- ***(6) Changes in pre-tax income:*** Pre-tax income is defined as total revenues minus total costs and is an indicator of profitability. Pre-tax income may decrease as a result of reductions in revenues and/or increases in costs.

- ***(7) Changes in variable production costs per MWh:*** 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 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. This measure presents similar information to total fuel and variable O&M costs under measure (5) above, but normalized for changes in generation.

[13] Such short-term capacity reductions would not be expressed as changes in available capacity but might affect electricity generation, production costs, and/or prices.

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

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

a. In-scope Phase II facilities as a group

The analysis of the in-scope Phase II facilities as a group 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 535 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) the number of Phase II facilities that experience closure of all their steam electric capacity is presented, and (3) repowering changes are not explicitly analyzed at the facility level. 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 535 Phase II facilities. A long-term reduction in availability may be the result of partial or full plant closures, a change in the decision to repower, or a change in the choice of air pollution control technologies. In the short term, temporary plant shut-downs for the installation of Phase II compliance technologies may lead to reductions in available capacity.[14] Under this measure, EPA also analyzed **closures**. Only capacity that is projected to remain operational in the base case but is closed in the post-compliance case is 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 unit or plant that would close in the base case but operates in the post-compliance case. At the facility-level, both the number of full closure facilities and closure capacity are analyzed.

- ***(2) Changes in generation:*** This measure considers the generation at the 535 Phase II facilities. Long-term changes in generation may be the result of a reduction in available capacity (see discussion above) or the 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 535 Phase II facilities. For some Phase II facilities, Phase II regulation 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 535 Phase II facilities and includes both energy revenues and capacity revenues (see definition in section B3-2.4 above). 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, Phase II regulation 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 costs:*** This measure considers changes in the overall cost of generating electricity for the 535 Phase II facilities, including fuel costs, variable and fixed O&M costs, and capital costs. **Fuel costs** and **variable O&M costs** are production costs that vary with the level of generation. Fuel costs generally account for the single largest share of production costs. **Fixed O&M costs** and **capital costs** do not vary with generation. They are fixed in the short-term and therefore do not affect the dispatch decision of a unit (given sufficient demand, a unit will dispatch as long as the price of electricity is at least equal to its per MWh production costs). However, in the long-run, these costs need to be recovered for a unit to remain economically viable.

- ***(5) Changes in pre-tax income:*** Pre-tax income is defined as total revenues minus total costs and is an indicator of profitability. Pre-tax income may decrease as a result of reductions in revenues and/or increases in costs.

- ***(6) Changes in variable production costs per MWh:*** 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.

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[14] Such short-term capacity reductions would not be expressed as changes in available capacity but might affect electricity generation, production costs, and/or prices.

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 three ranges: 1 percent or less, 1 to 3 percent, and more than 3 percent. 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 per MWh:*** See explanation in subsection a. above.
- ***(5) Changes in fuel costs per MWh:*** See explanation in subsection a. above.
- ***(6) Changes in pre-tax income:*** See explanation in subsection a. above.

B3-4 Analysis Results for the Final Rule

The remainder of this section presents the results of the economic impact analysis of the final Phase II rule for the ten NERC regions modeled by the IPM. The analysis is based on IPM output for the base case (using EPA electricity demand assumptions) and the final rule. Results are presented at the market level and the Phase II facility level.

The main analysis in this chapter uses output from model run year 2010. For this analysis, facilities subject to the final rule are assumed to come into compliance during the year of their first post-promulgation national pollution discharge elimination system (NPDES) permit (2005 to 2009). Therefore, 2010 is assumed to be the first year during which all facilities are in compliance, but no facilities experience technology installation downtimes. 2010 thus represents the post-compliance condition of the industry. EPA also analyzed potential market-level impacts of the final rule for a year within the compliance period during which some Phase II facilities experience installation downtimes. This secondary analysis represents potential short-term impacts of the final rule and uses output from model run year 2008.

B3-4.1 Market Analysis for 2010

This section presents the results of the IPM analysis for all facilities modeled by the IPM. The market-level analysis includes results for all generators located in each NERC region including facilities that are in-scope and facilities that are out-of-scope of Phase II regulation.

Table B3-4 presents the market-level impact measures discussed in section B3-3.1 above: (1) capacity changes, including changes in existing capacity, new additions, repowering additions, and closures; (2) electricity price changes, including changes in energy prices and capacity prices; (3) generation changes; (4) revenue changes; (5) cost changes, including changes in fuel costs, variable O&M costs, fixed O&M costs, and capital costs; (6) changes in pre-tax income; and (7) changes in variable production costs per MWh of generation. For each measure, the table presents the results for the base case and the final rule, the absolute difference between the two cases, and the percentage difference.

Table B3-4: Market-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	**EPA Base Case**	**Final Rule**	**Difference**	**% Change**
National Totals				
(1) Total Domestic Capacity (MW)	887,915	887,863	(52)	0.0%
(1a) Existing	787,280	786,922	(359)	0.0%
(1b) New Additions	79,683	79,540	(143)	(0.2)%
(1c) Repowering Additions	20,951	21,402	451	2.2%
(1d) Closures	14,122	14,274	152	1.1%
(2a) Energy Prices ($2002/MWh)	n/a	n/a	n/a	n/a
(2b) Capacity Prices ($2002/KW/yr)	n/a	n/a	n/a	n/a
(3) Generation (GWh)	4,113,839	4,113,668	(170)	0.0%
(4) Revenues (Millions; $2002)	$138,770	$138,676	($94)	(0.1)%
(5) Costs (Millions; $2002)	$87,486	$87,915	$429	0.5%
(5a) Fuel Cost	$47,789	$47,782	($7)	0.0%
(5b) Variable O&M	$7,926	$7,927	$1	0.0%
(5c) Fixed O&M	$23,417	$23,827	$410	1.8%
(5d) Capital Cost	$8,354	$8,378	$24	0.3%
(6) Pre-Tax Income (Millions; $2002)	$51,284	$50,761	($523)	(1.0)%
(7) Variable Production Costs ($/MWh)	$13.54	$13.54	$0.00	0.0%
East Central Area Reliability Coordination Agreement (ECAR)				
(1) Total Domestic Capacity (MW)	118,529	118,529	0	0.0%
(1a) Existing	110,066	110,066	0	0.0%
(1b) New Additions	8,394	8,394	0	0.0%
(1c) Repowering Additions	70	70	0	0.0%
(1d) Closures	0	0	0	0.0%
(2a) Energy Prices ($2002/MWh)	$22.63	$22.69	$0.06	0.3%
(2b) Capacity Prices ($2002/KW/yr)	$56.08	$56.15	$0.07	0.1%
(3) Generation (GWh)	649,024	647,671	(1,354)	(0.2)%
(4) Revenues (Millions; $2002)	$21,317	$21,334	$17	0.1%
(5) Costs (Millions; $2002)	$12,492	$12,576	$84	0.7%
(5a) Fuel Cost	$6,367	$6,358	($9)	(0.1)%
(5b) Variable O&M	$1,585	$1,583	($2)	(0.1)%
(5c) Fixed O&M	$3,570	$3,668	$98	2.7%
(5d) Capital Cost	$970	$968	($3)	(0.3)%
(6) Pre-Tax Income (Millions; $2002)	$8,825	$8,758	($67)	(0.8)%
(7) Variable Production Costs ($/MWh)	$12.25	$12.26	$0.01	0.1%
Electric Reliability Council of Texas (ERCOT)				
(1) Total Domestic Capacity (MW)	75,290	75,290	0	0.0%
(1a) Existing	71,901	71,721	(180)	(0.2)%
(1b) New Additions	2,053	1,871	(182)	(8.8)%
(1c) Repowering Additions	1,336	1,697	361	27.0%
(1d) Closures	0	0	0	0.0%

Table B3-4: Market-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	**EPA Base Case**	**Final Rule**	**Difference**	**% Change**
(2a) Energy Prices ($2002/MWh)	$29.38	$31.08	$1.69	5.8%
(2b) Capacity Prices ($2002/KW/yr)	$14.09	$4.83	($9.26)	(65.7)%
(3) Generation (GWh)	336,956	336,663	(293)	(0.1)%
(4) Revenues (Millions; $2002)	$10,961	$10,826	($135)	(1.2)%
(5) Costs (Millions; $2002)	$8,000	$8,031	$31	0.4%
(5a) Fuel Cost	$5,241	$5,234	($7)	(0.1)%
(5b) Variable O&M	$699	$700	$1	0.2%
(5c) Fixed O&M	$1,730	$1,754	$24	1.4%
(5d) Capital Cost	$330	$343	$13	4.1%
(6) Pre-Tax Income (Millions; $2002)	$2,961	$2,795	($166)	(5.6)%
(7) Variable Production Costs ($/MWh)	$17.63	$17.62	$0.00	0.0%
Florida Reliability Coordinating Council (FRCC)				
(1) Total Domestic Capacity (MW)	50,324	50,324	0	0.0%
(1a) Existing	39,262	39,267	5	0.0%
(1b) New Additions	11,062	11,057	(5)	0.0%
(1c) Repowering Additions	0	0	0	0.0%
(1d) Closures	812	812	0	0.0%
(2a) Energy Prices ($2002/MWh)	$29.39	$29.55	$0.16	0.6%
(2b) Capacity Prices ($2002/KW/yr)	$37.79	$36.82	($0.98)	(2.6)%
(3) Generation (GWh)	189,076	188,844	(232)	(0.1)%
(4) Revenues (Millions; $2002)	$7,459	$7,434	($25)	(0.3)%
(5) Costs (Millions; $2002)	$5,406	$5,442	$36	0.7%
(5a) Fuel Cost	$3,106	$3,113	$7	0.2%
(5b) Variable O&M	$364	$365	$2	0.4%
(5c) Fixed O&M	$1,184	$1,217	$33	2.8%
(5d) Capital Cost	$753	$747	($6)	(0.8)%
(6) Pre-Tax Income (Millions; $2002)	$2,053	$1,992	($61)	(3.0)%
(7) Variable Production Costs ($/MWh)	$18.35	$18.42	$0.07	0.4%
Mid-Atlantic Area Council (MAAC)				
(1) Total Domestic Capacity (MW)	63,784	63,784	0	0.0%
(1a) Existing	56,355	56,355	0	0.0%
(1b) New Additions	5,771	5,771	0	0.0%
(1c) Repowering Additions	1,658	1,658	0	0.0%
(1d) Closures	2,831	2,831	0	0.0%
(2a) Energy Prices ($2002/MWh)	$26.73	$26.76	$0.02	0.1%
(2b) Capacity Prices ($2002/KW/yr)	$50.61	$50.44	($0.17)	(0.3)%
(3) Generation (GWh)	276,051	277,764	1,714	0.6%
(4) Revenues (Millions; $2002)	$10,605	$10,646	$41	0.4%
(5) Costs (Millions; $2002)	$6,124	$6,206	$82	1.3%
(5a) Fuel Cost	$3,066	$3,101	$34	1.1%

Table B3-4: Market-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	**EPA Base Case**	**Final Rule**	**Difference**	**% Change**
(5b) Variable O&M	$557	$560	$3	0.5%
(5c) Fixed O&M	$1,929	$1,969	$39	2.0%
(5d) Capital Cost	$571	$577	$5	0.9%
(6) Pre-Tax Income (Millions; $2002)	$4,481	$4,440	($41)	(0.9)%
(7) Variable Production Costs ($/MWh)	$13.13	$13.18	$0.05	0.4%
Mid-America Interconnected Network (MAIN)				
(1) Total Domestic Capacity (MW)	59,494	59,397	(97)	(0.2)%
(1a) Existing	51,551	51,465	(86)	(0.2)%
(1b) New Additions	7,943	7,932	(11)	(0.1)%
(1c) Repowering Additions	0	0	0	0.0%
(1d) Closures	5,191	5,285	94	1.8%
(2a) Energy Prices ($2002/MWh)	$22.66	$22.60	($0.06)	(0.3)%
(2b) Capacity Prices ($2002/KW/yr)	$54.31	$54.66	$0.35	0.7%
(3) Generation (GWh)	281,625	281,446	(179)	(0.1)%
(4) Revenues (Millions; $2002)	$9,607	$9,602	($5)	(0.1)%
(5) Costs (Millions; $2002)	$5,795	$5,802	$7	0.1%
(5a) Fuel Cost	$2,930	$2,933	$3	0.1%
(5b) Variable O&M	$586	$583	($3)	(0.5)%
(5c) Fixed O&M	$1,710	$1,726	$15	0.9%
(5d) Capital Cost	$569	$560	($9)	(1.6)%
(6) Pre-Tax Income (Millions; $2002)	$3,812	$3,800	($11)	(0.3)%
(7) Variable Production Costs ($/MWh)	$12.48	$12.49	$0.01	0.1%
Mid-Continent Area Power Pool (MAPP)				
(1) Total Domestic Capacity (MW)	35,835	35,835	0	0.0%
(1a) Existing	32,672	32,676	4	0.0%
(1b) New Additions	3,163	3,159	(4)	(0.1)%
(1c) Repowering Additions	0	0	0	0.0%
(1d) Closures	476	476	0	0.0%
(2a) Energy Prices ($2002/MWh)	$21.86	$21.79	($0.06)	(0.3)%
(2b) Capacity Prices ($2002/KW/yr)	$54.00	$54.49	$0.49	0.9%
(3) Generation (GWh)	181,713	181,566	(147)	(0.1)%
(4) Revenues (Millions; $2002)	$5,878	$5,881	$3	0.0%
(5) Costs (Millions; $2002)	$3,430	$3,431	$1	0.0%
(5a) Fuel Cost	$1,722	$1,719	($3)	(0.2)%
(5b) Variable O&M	$381	$379	($2)	(0.5)%
(5c) Fixed O&M	$1,017	$1,029	$12	1.2%
(5d) Capital Cost	$311	$304	($7)	(2.2)%
(6) Pre-Tax Income (Millions; $2002)	$2,448	$2,450	$2	0.1%
(7) Variable Production Costs ($/MWh)	$11.57	$11.56	($0.02)	(0.1)%

Table B3-4: Market-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	**EPA Base Case**	**Final Rule**	**Difference**	**% Change**
Northeast Power Coordinating Council (NPCC)				
(1) Total Domestic Capacity (MW)	72,477	72,459	(19)	0.0%
(1a) Existing	59,515	59,513	(2)	0.0%
(1b) New Additions	2,082	2,061	(21)	(1.0)%
(1c) Repowering Additions	10,881	10,885	4	0.0%
(1d) Closures	4,107	4,107	0	0.0%
(2a) Energy Prices ($2002/MWh)	$29.88	$29.85	($0.02)	(0.1)%
(2b) Capacity Prices ($2002/KW/yr)	$43.23	$43.22	($0.01)	0.0%
(3) Generation (GWh)	278,649	277,433	(1,216)	(0.4)%
(4) Revenues (Millions; $2002)	$11,220	$11,173	($46)	(0.4)%
(5) Costs (Millions; $2002)	$7,732	$7,751	$18	0.2%
(5a) Fuel Cost	$4,479	$4,438	($41)	(0.9)%
(5b) Variable O&M	$376	$372	($4)	(1.0)%
(5c) Fixed O&M	$1,781	$1,846	$65	3.6%
(5d) Capital Cost	$1,096	$1,095	($2)	(0.1)%
(6) Pre-Tax Income (Millions; $2002)	$3,488	$3,423	($65)	(1.9)%
(7) Variable Production Costs ($/MWh)	$17.42	$17.34	($0.08)	(0.5)%
Southeastern Electric Reliability Council (SERC)				
(1) Total Domestic Capacity (MW)	194,485	194,472	(13)	0.0%
(1a) Existing	164,544	164,544	0	0.0%
(1b) New Additions	29,941	29,928	(13)	0.0%
(1c) Repowering Additions	0	0	0	0.0%
(1d) Closures	0	0	0	0.0%
(2a) Energy Prices ($2002/MWh)	$24.64	$24.62	($0.02)	(0.1)%
(2b) Capacity Prices ($2002/KW/yr)	$48.23	$48.40	$0.17	0.4%
(3) Generation (Gwh)	944,631	945,913	1,283	0.1%
(4) Revenues (Millions; $2002)	$32,644	$32,690	$46	0.1%
(5) Costs (Millions; $2002)	$19,753	$19,865	$112	0.6%
(5a) Fuel Cost	$10,314	$10,323	$8	0.1%
(5b) Variable O&M	$1,785	$1,790	$5	0.3%
(5c) Fixed O&M	$5,264	$5,343	$79	1.5%
(5d) Capital Cost	$2,389	$2,408	$20	0.8%
(6) Pre-Tax Income (Millions; $2002)	$12,891	$12,826	($66)	(0.5)%
(7) Variable Production Costs ($/MWh)	$12.81	$12.81	$0.00	0.0%
Southwest Power Pool (SPP)				
(1) Total Domestic Capacity (MW)	49,948	50,092	144	0.3%
(1a) Existing	48,956	48,900	(56)	(0.1)%
(1b) New Additions	992	1,080	88	8.9%
(1c) Repowering Additions	0	111	111	100.0%

Table B3-4: Market-Level Impacts of the Final Rule (by NERC Region; 2010)

Economic Measures	EPA Base Case	Final Rule	Difference	% Change
(1d) Closures	0	0	0	0.0%
(2a) Energy Prices ($2002/MWh)	$24.34	$24.29	($0.05)	(0.2)%
(2b) Capacity Prices ($2002/KW/yr)	$40.97	$41.24	$0.27	0.7%
(3) Generation (GWh)	221,527	221,854	327	0.1%
(4) Revenues (Millions; $2002)	$7,434	$7,450	$16	0.2%
(5) Costs (Millions; $2002)	$4,254	$4,282	$28	0.7%
(5a) Fuel Cost	$2,701	$2,702	$1	0.0%
(5b) Variable O&M	$422	$422	($1)	(0.1)%
(5c) Fixed O&M	$1,042	$1,057	$14	1.4%
(5d) Capital Cost	$88	$101	$13	14.7%
(6) Pre-Tax Income (Millions; $2002)	$3,181	$3,168	($12)	(0.4)%
(7) Variable Production Costs ($/MWh)	$14.10	$14.08	($0.02)	(0.1)%
Western Systems Coordinating Council (WSCC)				
(1) Total Domestic Capacity (MW)	167,748	167,681	(67)	0.0%
(1a) Existing	152,459	152,414	(45)	0.0%
(1b) New Additions	8,283	8,287	4	0.0%
(1c) Repowering Additions	7,006	6,980	(26)	(0.4)%
(1d) Closures	705	763	58	8.2%
(2a) Energy Prices ($2002/MWh)	$27.19	$27.18	($0.01)	0.0%
(2b) Capacity Prices ($2002/KW/yr)	$7.56	$7.58	$0.03	0.3%
(3) Generation (GWh)	754,587	754,514	(73)	0.0%
(4) Revenues (Millions; $2002)	$21,645	$21,639	($6)	0.0%
(5) Costs (Millions; $2002)	$14,499	$14,530	$30	0.2%
(5a) Fuel Cost	$7,863	$7,862	($1)	0.0%
(5b) Variable O&M	$1,171	$1,173	$1	0.1%
(5c) Fixed O&M	$4,189	$4,220	$31	0.7%
(5d) Capital Cost	$1,277	$1,275	($2)	(0.1)%
(6) Pre-Tax Income (Millions; $2002)	$7,146	$7,110	($36)	(0.5)%
(7) Variable Production Costs ($/MWh)	$11.97	$11.97	$0.00	0.0%

Source: IPM analysis: Model runs for Section 316(b) NODA Base Case and the final rule (EPA electricity demand assumptions).

Summary of Market Results at the National Level. The results presented in Table B3-4 show that capacity closures are estimated to increase by 152 MW, which represents 0.02 percent of total baseline capacity. New additions are estimated to decrease by 143 MW. An increase in repowering additions (451 MW) is estimated to make up for this loss. Total costs of electricity generation will increase by 0.5 percent, largely because of a 1.8 percent increase in fixed O&M costs (which includes charges for capital costs of compliance). Revenues are estimated to decrease by 0.1 percent and pre-tax income is estimated to decrease by 1.0 percent. The final rule will not lead to changes in total domestic capacity or total fuel costs.

Summary of Market Results at the Regional Level. At the regional level, the final rule is estimated to result in the following changes:

- **MAIN** and **WSCC** are the only regions that are estimated to experience an increase in post-compliance capacity closures. In MAIN, the 94 MW increase in closures (0.2 percent of baseline capacity) is due to a nuclear facility that reached the end of its nuclear operating license. In the base case, this facility would have extended its license for 481 MW of capacity and continued operation until 2020. Under the final rule, however, this facility is modeled to only extend its license for 387 MW of capacity. As a result, MAIN also experiences a decrease in capital costs. In WSCC, oil and gas early retirements account for the 58 MW increase in closures (less than 0.1 percent of baseline capacity). All other measures are estimated to change by less than 1.0 percent.

- **ERCOT** is estimated to experience the most notable changes in electricity prices and new capacity among the ten NERC regions. Repowering additions will increase by 361 MW (0.5 percent of baseline capacity) under the final rule. Repowering in the IPM is modeled as a conversion of one MW of existing coal or oil and gas steam capacity into two MW of combined-cycle capacity. As such, repowering in ERCOT under the final rule consists of the conversion of 180 MW of existing capacity into 361 MW of new repowered capacity. Since total capacity in ERCOT remains constant, this 181 MW net increase in capacity is offset by a 182 MW decrease in new capacity additions. Repowering of oil and gas to combined cycle will cause capital costs to increase by 4.1 percent. Post-compliance energy prices are estimated to increase by 5.8 percent. This increase is largely driven by relatively low profit margins in the region. ERCOT also experiences the largest reduction in capacity prices with almost 66 percent. This is partially due to the increase in energy prices, which allows facilities to bid their undispatched capacity at a lower price. Revenues and pre-tax income in ERCOT are estimated to fall by 1.2 percent and 5.6 percent, respectively, the highest in any NERC region.

- **FRCC** is estimated to experience a 2.6 percent reduction in capacity prices. Revenues in FRCC are estimated to decrease by 0.3 percent and costs will increase by 0.7 percent (largely due to an increase in fixed O&M costs of 2.8 percent), leading to a reduction in pre-tax income of 3.0 percent the second highest in any NERC region. All other measures are estimated to change by less than 1.0 percent.

- **NPCC** is estimated to have the largest percentage reduction in generation of the ten NERC regions (0.4 percent). As a result variable O&M costs decreases by 1.0 percent. Fixed O&M costs, which include the capital costs of compliance with the final rule, increase by 3.6 percent, and pre-tax income decreases by 1.9 percent, the third highest in any NERC region. Revenues and overall costs in NPCC are estimated to each change by less than 0.5 percent.

- **ECAR**, **MAPP,** and **SERC**, are estimated to experience increases in fixed O&M costs, driven by the capital costs of compliance with the final rule, but overall cost increases in each region will be less than 1.0 percent. Pre-tax income in these regions is estimated to decrease by between 0.5 and 0.8 percent, with the exception of MAPP which is estimated to experience a slight increase in pre-tax income. MAPP will also experience a decrease in capital costs (2.2 percent) due to the avoided cost of retrofitting a scrubber. All other measures are estimated to change by less than 1.0 percent.

- **SPP** is the only region estimated to experience an increase in total capacity. This increase is the result of 88 MW in incremental new additions and 111 MW in repowering additions. However, these changes represent less than 0.5 percent of overall capacity. Similar to ECAR, MAPP, and SERC, SPP will experience increases in fixed O&M costs. SPP is estimated to have the largest increase in capital costs of the ten NERC regions (14.7 percent). The majority of additional capital costs comes from the repowering additions. Pretax income is estimated to decrease by 0.4 percent.

- **MAAC** is estimated to experience the largest increase in generation (0.6 percent) and fuel cost (1.1 percent) as a result of the final rule. Fixed O&M costs are estimated to rise by 2.0 percent, leading to an increase in total costs of 1.3 percent. Together with FRCC, MAAC also has the largest increase in variable production cost per MWh of generation, 0.4 percent. All other measures are estimated to change by less than 1.0 percent.

B3-4.2 Analysis of Phase II Facilities for 2010

This section presents the results of the IPM analysis for the Phase II facilities that are modeled by the IPM. Ten of the 535 Phase II facilities are closures in the base case, and 11 facilities are closures under the final rule. These facilities are not represented in the results described in this section.

EPA used the IPM results from model run year 2010 to analyze impacts on Phase II facilities at two levels: (1) potential changes in the economic and operational characteristics of the in-scope Phase II facilities as a group and (2) potential changes to individual facilities within the group of in-scope Phase II facilities.

a. In-scope Phase II facilities as a group

This section presents the analysis of the potential impacts of the final rule on the in-scope Phase II facilities as a group. This analysis 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 B3-5 presents the impact measures for the group of Phase II facilities discussed in section B3-3.2 above: (1) capacity changes, including changes in the number and capacity of closure facilities; (2) generation changes; (3) revenue changes; (4) cost changes, including changes in fuel costs, variable O&M costs, fixed O&M costs, and capital costs; (5) changes in pre-tax income; and (6) changes in variable production costs per MWh of generation, where variable production cost is defined as the sum of fuel cost and variable O&M cost. For each measure, the table presents the results for the base case and the final rule, the absolute difference between the two cases, and the percentage difference.

Table B3-5: Facility-Level Impacts of the Final Rule (by NERC Region; 2010)

Economic Measures	EPA Base Case	Final Rule	Difference	% Change
National Totals				
(1) Total Domestic Capacity (MW)	433,998	433,062	(936)	(0.2)%
(1a) Closures - Number of Facilities	10	11	1	10.0%
(1b) Closures - Capacity (MW)	13,644	13,796	152	1.1%
(2) Generation (GWh)	2,323,322	2,304,461	(18,861)	(0.8)%
(3) Revenues (Millions; $2002)	$76,259	$75,585	($673)	(0.9)%
(4) Costs (Millions; $2002)	$48,264	$48,092	($173)	(0.4)%
(4a) Fuel Cost	$25,391	$24,990	($400)	(1.6)%
(4b) Variable O&M	$5,154	$5,130	($24)	(0.5)%
(4c) Fixed O&M	$15,159	$15,552	$393	2.6%
(4d) Capital Cost	$2,561	$2,420	($142)	(5.5)%
(5) Pre-Tax Income (Millions; $2002)	$27,994	$27,494	($501)	(1.8)%
(6) Variable Production Costs ($2002/MWh)	$13.15	$13.07	($0.08)	(0.6)%
East Central Area Reliability Coordination Agreement (ECAR)				
(1) Total Domestic Capacity (MW)	82,313	82,313	0	0.0%
(1a) Closures - Number of Facilities	0	0	0	0.0%
(1b) Closures - Capacity (MW)	1	1	0	0.0%
(2) Generation (GWh)	517,126	516,220	(906)	(0.2)%
(3) Revenues (Millions; $2002)	$16,237	$16,250	$13	0.1%
(4) Costs (Millions; $2002)	$9,586	$9,668	$82	0.9%
(4a) Fuel Cost	$5,036	$5,022	($14)	(0.3)%
(4b) Variable O&M	$1,248	$1,248	$0	0.0%
(4c) Fixed O&M	$2,961	$3,059	$98	3.3%
(4d) Capital Cost	$342	$340	($2)	(0.7)%
(5) Pre-Tax Income (Millions; $2002)	$6,651	$6,582	($69)	(1.0)%
(6) Variable Production Costs ($2002/MWh)	$12.15	$12.15	($0.01)	0.0%
Electric Reliability Council of Texas (ERCOT)				
(1) Total Domestic Capacity (MW)	43,522	43,413	(109)	(0.3)%
(1a) Closures - Number of Facilities	0	0	0	0.0%
(1b) Closures - Capacity (MW)	0	0	0	0
(2) Generation (GWh)	158,462	155,661	(2,800)	(1.8)%

Table B3-5: Facility-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	**EPA Base Case**	**Final Rule**	**Difference**	**% Change**
(3) Revenues (Millions; $2002)	$5,365	$5,158	($206)	(3.8)%
(4) Costs (Millions; $2002)	$3,910	$3,855	($55)	(1.4)%
(4a) Fuel Cost	$2,203	$2,142	($61)	(2.8)%
(4b) Variable O&M	$426	$422	($4)	(0.9)%
(4c) Fixed O&M	$1,181	$1,204	$23	1.9%
(4d) Capital Cost	$99	$86	($13)	(12.9)%
(5) Pre-Tax Income (Millions; $2002)	$1,455	$1,303	($152)	(10.4)%
(6) Variable Production Costs ($2002/MWh)	$16.59	$16.48	($0.12)	(0.7)%
Florida Reliability Coordinating Council (FRCC)				
(1) Total Domestic Capacity (MW)	27,537	27,542	5	0.0%
(1a) Closures - Number of Facilities	0	0	0	0.0%
(1b) Closures - Capacity (MW)	812	812	0	0.0%
(2) Generation (GWh)	82,259	81,631	(628)	(0.8)%
(3) Revenues (Millions; $2002)	$3,433	$3,398	($35)	(1.0)%
(4) Costs (Millions; $2002)	$2,021	$2,042	$21	1.0%
(4a) Fuel Cost	$1,154	$1,148	($6)	(0.5)%
(4b) Variable O&M	$188	$187	$0	(0.2)%
(4c) Fixed O&M	$673	$706	$33	4.9%
(4d) Capital Cost	$5	$0	($5)	(100.0)%
(5) Pre-Tax Income (Millions; $2002)	$1,412	$1,356	($56)	(4.0)%
(6) Variable Production Costs ($2002/MWh)	$16.31	$16.36	$0.05	0.3%
Mid-Atlantic Area Council (MAAC)				
(1) Total Domestic Capacity (MW)	34,376	34,376	0	0.0%
(1a) Closures - Number of Facilities	2	2	0	0.0%
(1b) Closures - Capacity (MW)	2,831	2,831	0	0.0%
(2) Generation (GWh)	173,473	173,782	309	0.2%
(3) Revenues (Millions; $2002)	$6,339	$6,343	$4	0.1%
(4) Costs (Millions; $2002)	$3,617	$3,658	$42	1.2%
(4a) Fuel Cost	$1,693	$1,696	$3	0.2%
(4b) Variable O&M	$355	$356	$1	0.3%
(4c) Fixed O&M	$1,438	$1,476	$38	2.6%
(4d) Capital Cost	$131	$131	$0	0.0%
(5) Pre-Tax Income (Millions; $2002)	$2,722	$2,685	($37)	(1.4)%
(6) Variable Production Costs ($2002/MWh)	$11.81	$11.81	$0.00	0.0%
Mid-America Interconnected Network (MAIN)				
(1) Total Domestic Capacity (MW)	36,498	36,412	(86)	(0.2)%
(1a) Closures - Number of Facilities	2	2	0	0.0%
(1b) Closures - Capacity (MW)	5,191	5,285	94	1.8%
(2) Generation (GWh)	226,437	225,826	(610)	(0.3)%

Table B3-5: Facility-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	**EPA Base Case**	**Final Rule**	**Difference**	**% Change**
(3) Revenues (Millions; $2002)	$7,011	$6,993	($17)	(0.2)%
(4) Costs (Millions; $2002)	$4,196	$4,196	$0	0.0%
(4a) Fuel Cost	$2,109	$2,108	($1)	(0.1)%
(4b) Variable O&M	$510	$506	($3)	(0.7)%
(4c) Fixed O&M	$1,472	$1,486	$14	1.0%
(4d) Capital Cost	$106	$96	($9)	(8.9)%
(5) Pre-Tax Income (Millions; $2002)	$2,815	$2,797	($18)	(0.6)%
(6) Variable Production Costs ($2002/MWh)	$11.56	$11.58	$0.01	0.1%
Mid-Continent Area Power Pool (MAPP)				
(1) Total Domestic Capacity (MW)	15,749	15,753	4	0.0%
(1a) Closures - Number of Facilities	1	1	0	0.0%
(1b) Closures - Capacity (MW)	476	476	0	0.0%
(2) Generation (GWh)	108,584	108,533	(52)	0.0%
(3) Revenues (Millions; $2002)	$3,178	$3,179	$1	0.0%
(4) Costs (Millions; $2002)	$1,978	$1,982	$4	0.2%
(4a) Fuel Cost	$1,044	$1,044	$0	0.0%
(4b) Variable O&M	$222	$221	($2)	(0.7)%
(4c) Fixed O&M	$597	$609	$12	2.0%
(4d) Capital Cost	$114	$107	($6)	(5.7)%
(5) Pre-Tax Income (Millions; $2002)	$1,200	$1,197	($3)	(0.3)%
(6) Variable Production Costs ($2002/MWh)	$11.67	$11.65	($0.01)	(0.1)%
Northeast Power Coordinating Council (NPCC)				
(1) Total Domestic Capacity (MW)	37,651	37,343	(308)	(0.8)%
(1a) Closures - Number of Facilities	4	4	0	0.0%
(1b) Closures - Capacity (MW)	4,107	4,107	0	0.0%
(2) Generation (GWh)	165,601	159,701	(5,900)	(3.6)%
(3) Revenues (Millions; $2002)	$6,503	$6,300	($203)	(3.1)%
(4) Costs (Millions; $2002)	$5,114	$4,971	($143)	(2.8)%
(4a) Fuel Cost	$2,756	$2,607	($149)	(5.4)%
(4b) Variable O&M	$276	$266	($9)	(3.4)%
(4c) Fixed O&M	$1,242	$1,305	$62	5.0%
(4d) Capital Cost	$840	$793	($47)	(5.6)%
(5) Pre-Tax Income (Millions; $2002)	$1,389	$1,329	($60)	(4.3)%
(6) Variable Production Costs ($2002/MWh)	$18.31	$17.99	($0.32)	(1.7)%
Southeastern Electric Reliability Council (SERC)				
(1) Total Domestic Capacity (MW)	107,450	107,450	0	0.0%
(1a) Closures - Number of Facilities	0	0	0	0.0%
(1b) Closures - Capacity (MW)	0	0	0	0.0%
(2) Generation (GWh)	639,276	637,804	(1,472)	(0.2)%
(3) Revenues (Millions; $2002)	$20,645	$20,617	($28)	(0.1)%

Table B3-5: Facility-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	**EPA Base Case**	**Final Rule**	**Difference**	**% Change**
(4) Costs (Millions; $2002)	$12,038	$12,071	$34	0.3%
(4a) Fuel Cost	$6,137	$6,097	($39)	(0.6)%
(4b) Variable O&M	$1,365	$1,366	$2	0.1%
(4c) Fixed O&M	$3,986	$4,058	$72	1.8%
(4d) Capital Cost	$550	$549	($1)	(0.2)%
(5) Pre-Tax Income (Millions; $2002)	$8,607	$8,546	($62)	(0.7)%
(6) Variable Production Costs ($2002/MWh)	$11.73	$11.70	($0.03)	(0.3)%
Southwest Power Pool (SPP)				
(1) Total Domestic Capacity (MW)	20,471	20,471	0	0.0%
(1a) Closures - Number of Facilities	0	0	0	0.0%
(1b) Closures - Capacity (MW)	0	0	0	0.0%
(2) Generation (GWh)	109,901	109,185	(716)	(0.7)%
(3) Revenues (Millions; $2002)	$3,419	$3,401	($18)	(0.5)%
(4) Costs (Millions; $2002)	$1,962	$1,958	($3)	(0.2)%
(4a) Fuel Cost	$1,148	$1,135	($13)	(1.2)%
(4b) Variable O&M	$248	$247	($2)	(0.6)%
(4c) Fixed O&M	$557	$569	$13	2.3%
(4d) Capital Cost	$8	$7	($1)	(13.9)%
(5) Pre-Tax Income (Millions; $2002)	$1,457	$1,443	($14)	(1.0)%
(6) Variable Production Costs ($2002/MWh)	$12.71	$12.65	($0.05)	(0.4)%
Western Systems Coordinating Council (WSCC)				
(1) Total Domestic Capacity (MW)	28,431	27,989	(443)	-1.6%
(1a) Closures - Number of Facilities	1	2	1	100.0%
(1b) Closures - Capacity (MW)	226	284	58	25.7%
(2) Generation (GWh)	142,204	136,117	(6,086)	-4.3%
(3) Revenues (Millions; $2002)	$4,131	$3,947	($183)	-4.4%
(4) Costs (Millions; $2002)	$3,844	$3,691	($153)	-4.0%
(4a) Fuel Cost	$2,109	$1,990	($119)	-5.6%
(4b) Variable O&M	$317	$311	($6)	-1.9%
(4c) Fixed O&M	$1,051	$1,079	$28	2.6%
(4d) Capital Cost	$367	$310	($56)	-15.4%
(5) Pre-Tax Income (Millions; $2002)	$287	$257	($30)	-10.4%
(6) Variable Production Costs ($2002/MWh)	$17.06	$16.90	($0.15)	-0.9%

Source: IPM analysis: Model runs for Section 316(b) NODA Base Case and the final rule (EPA electricity demand assumptions).

Comparison of Results for Phase II Facilities and the Market. The IPM results for the in-scope Phase II facilities as a group (presented in Table B3-5) are similar to the results at the market level (presented in Table B3-4). On a percentage basis, the group of Phase II facilities generally experiences higher losses in generation, revenues, and pre-tax income compared to the overall market. This is not surprising as in-scope facilities become relatively less competitive compared to facilities not in scope of Phase II regulation and are therefore likely to lose some market share as a result of the final rule.

Total closure capacity among the Phase II facilities is the same as at the market level but represents a higher percentage of total base case capacity. Fixed O&M costs of the group of Phase II facilities increase relatively more than at the market level because fixed O&M costs include the capital costs of compliance with Phase II regulatory options. In many regions, however, the other cost accounts decrease for the Phase II facilities because of the reduction in generation. On a per MWh basis, variable production costs also decrease in many regions because the higher cost units generate less electricity under the final rule compared to the base case, reducing the overall average cost of generation.

Summary of Phase II Facility Results at the National Level. Table B3-5 shows that the final rule will lead to 152 MW in incremental capacity closures, or less than 0.5 percent of baseline Phase II capacity. These incremental closures are estimated to be one full facility closure of 19 MW in WSCC and partial facility closures of 39 MW in WSCC and 94 MW in MAIN. Total Phase II capacity is projected to decrease by 936 MW, due to the capacity closures and several facilities that were projected to repower in the base case but do not under the final rule. As a result, generation, revenues, and overall costs will decrease but by less than one percent. Fixed O&M costs, which include the capital cost of compliance, are projected to increase by 2.6 percent. Pre-tax income for the group of Phase II facilities will decrease by 1.8 percent.

Summary of Phase II Facility Results at the Regional Level. Results for the final rule vary somewhat by region. For many regions, impacts follow the general pattern described in the comparison to the market level above: generation, revenues, and pre-tax income decrease. Overall costs decrease in many regions due to lower levels of generation but increase in other regions where the additional compliance costs outweigh the reduction in generation. In addition to these general patterns, EPA estimates that the final rule will result in the following changes:

- **WSCC** is estimated to experience the largest reduction in Phase II capacity, losing 443 MW, or 1.6 percent of base case capacity under the final rule. This change is partially the result of a full facility closure of 19 MW and a partial facility closure of 39 MW. However, the majority of the 443 MW reduction is the result of less Phase II capacity being repowered in the post-compliance scenario. Phase II facilities in WSCC also experience the largest reductions in generation and revenues of any NERC region (4.3 and 4.4 percent, respectively) because they bear a relatively high compliance cost per MW of capacity under the final rule (the second highest of any of the 10 NERC regions). In addition, only a small percentage of total capacity in WSCC (28,400 MW out of 167,750 MW, or 17 percent) is subject to Phase II regulation. As a result, facilities not subject to Phase II regulation become relatively more competitive and assume some of the generation lost by Phase II facilities. Overall, costs for the group of Phase II facilities decrease by 4.0 percent. Fixed O&M costs, which include Phase II compliance costs, increase but fuel costs and variable O&M costs decrease because of the reduction in generation. However, the reduction in revenues outweighs the reduction in costs, leading to an overall reduction in pre-tax income of 10.4 percent ($30 million), which is the highest, together with ERCOT, in any NERC region. This relatively high percentage reduction is partially due to the low profit margins of Phase II facilities in WSCC in the base case.

- **MAIN** is the only other region, besides WSCC, that is projected to experience an incremental closure of Phase II capacity under the final rule, losing 94 MW of capacity (0.3% of base case capacity). The reduction is due to a nuclear facility that reached the end of its nuclear operating license. In the base case the facility would have extended its license for 481 MW of capacity, and continued operating until 2020. Under the final rule the facility only extends its license for 387 MW of capacity. The incremental capacity closure is responsible for the reduction in Phase II capacity in the region and contributes to a decrease in Phase II post-compliance generation and revenues. Total costs remain the same, but variable production cost per MWh increase because the projected incremental closure affects nuclear capacity which has lower production costs than most other plant types.

- Phase II facilities in **ERCOT** are estimated to experience the highest reductions pre-tax income (-10.4 percent), together with facilities in WSCC. In addition, generation (-1.8 percent) and revenues (-3.8 percent) are predicted to decrease. Revenues decrease by a larger percentage than generation due to the large drop in capacity prices (see Table B3-4). Capital costs decrease by 12.9 percent (the largest reduction other than FRCC). A majority of the reduction is the result of one less facility repowering under the final rule.

- Phase II facilities in **NPCC** are estimated to experience the largest increase in fixed O&M costs of any NERC region (5.0 percent) as a result of bearing the highest compliance cost per MW of capacity under the final rule. NPCC facilities will also experience the second largest reduction in generation (-3.6 percent) and the third largest reduction in pre-tax income (-4.3 percent) of any region.

- Phase II facilities in **FRCC** are estimated to experience an increase in total costs of 1.0 percent under the final rule, which is driven by a 4.9 percent increase in fixed O&M costs. Combined with a reduction in revenues of 1.0 percent, this will reduce pre-tax income for Phase II facilities in FRCC by 4.0 percent.

- **ECAR**, **MAAC**, **MAPP**, and **SERC**, and **SPP** are estimated to experience relatively small reductions in pre-tax income (between 0.3 and 1.4 percent) as a result of increases in fixed O&M costs (between 1.8 to 3.3 percent). The changes in most other measures are less than 1.0 percent in these regions.

b. Individual Phase II facilities

In addition to effects of the final rule on the in-scope Phase II facilities as a group, there may be shifts in economic performance among individual facilities subject to Phase II regulation. To assess such potential shifts, EPA analyzed facility-specific changes in (1) capacity utilization (defined as generation divided by capacity multiplied by the number of hours per year – 8,760); (2) generation; (3) revenues; (4) variable production costs per MWh of generation (defined as variable O&M cost plus fuel cost divided by generation); (5) fuel cost per MWh of generation; and (6) pre-tax income. For each measure, EPA determined the number of Phase II facilities that experience no changes, or an increase or a reduction within three ranges: 1 percent or less, 1 to 3 percent, and more than 3 percent.

Table B3-6 presents the total number of Phase II facilities with different estimated degrees of change due to the final rule. This table excludes 17 in-scope facilities with estimated significant status changes in 2010: Ten facilities are baseline closures, one facility is a full closure as a result of the final rule, and six facilities changed their repowering decision between the base case and the post-compliance case. These facilities are either not operating at all in either the base case or the post-compliance case, or they experience fundamental changes in the type of units they operate; therefore, the measures presented in Table B3-6 would not be meaningful for these facilities. In addition, the change in variable production cost per MWh and fuel cost per MWh of generation could not be developed for 57 facilities with zero generation in either the base case or post-compliance scenario. For these facilities, the change in variable production cost per MWh is indicated as "n/a."

Table B3-6: Number of Individual Phase II Facilities with Operational Changes (2010)

Economic Measures	Reduction			Increase			No Change	N/A
	</= 1%	1-3%	> 3%	</= 1%	1-3%	> 3%		
(1) Change in Capacity Utilization	6	21	25	7	7	11	441	0
(2) Change in Generation	4	6	46	11	5	18	428	0
(3) Change in Revenues	83	30	45	142	8	16	194	0
(4) Change in Variable Production Costs/MWh	38	16	9	145	11	17	225	57
(5) Change in Fuel Costs/MWh	27	14	10	38	8	13	351	57
(6) Change in Pre-Tax Income	115	109	213	44	11	15	11	0

[a] For all measures percentages used to assign facilities to impact categories have been rounded to the nearest 10th of a percent.
[b] The change in capacity utilization is the difference between the capacity utilization percentages in the base case and post-compliance case. For all other measures, the change is expressed as the percentage change between the base case and post-compliance values.

Source: IPM analysis: Model runs for Section 316(b) NODA Base Case and the final rule (EPA electricity demand assumptions).

Table B3-6 indicates that the majority of Phase II facilities will not experience changes in capacity utilization, generation, or fuel costs per MWh due to compliance with the final rule. Of those facilities with changes in post-compliance capacity utilization and generation, most will experience decreases in these measures. The majority of facilities with changes in post-compliance variable production costs per MWh will experience increases. However, more than 80 percent of those increases will not exceed 1.0 percent. Changes in revenues at most Phase II facilities will also not exceed 1.0 percent. The largest effect of the final rule will be on facilities' pre-tax income: over 80 percent of facilities will experience a reduction in pre-tax income, with about 40 percent experiencing a reduction of 3.0 percent or greater. These reductions are due to a combination of reduced revenues and increased compliance costs.

B3-4.3 Market Analysis for 2008

This section presents market-level results for the final rule for model run year 2008. Unlike the market-level analysis for 2010 described above, model run year 2008 includes facilities that experience a one-time downtime due to the installation of Phase II compliance technologies. This analysis therefore presents potential short-term effects that may occur during the five-year period (2005 to 2009) represented by model run year 2008. However, it should be noted that not all facilities are in compliance by 2008. Therefore, potential effects of installation downtimes may be mitigated by the fact that some facilities will not incur compliance costs until after 2008.

Table B3-7 presents the following market-level impacts for 2008: (1) electricity price changes, including changes in energy prices and capacity prices; (2) generation changes; (3) revenue changes; (4) cost changes, including changes in fuel costs, variable O&M costs, fixed O&M costs, and capital costs; (5) changes in pre-tax income; and (6) changes in variable production costs per MWh. For each measure, the table presents the 2008 results for the base case and the final rule, the absolute difference between the two cases, and the percentage difference. The table also repeats the percentage difference based on the market-level analysis for 2010 presented in Table B3-4 above.

Table B3-7: Market-Level Impacts of the Final Rule (NERC 2008 and 2010)

Economic Measures	EPA Base Case	Final Rule	Difference	% Change	% Change 2010
National Totals					
(1a) Energy Price ($2002/MWh)	n/a	n/a	n/a	n/a	n/a
(1b) Capacity Price ($2002/KW)	n/a	n/a	n/a	n/a	n/a
(2) Total Generation (GWh)	4,060,238	4,060,401	163	0.0%	0.0%
(3) Total Revenues (Millions; $2002)	$154,018	$153,946	($72)	0.0%	(0.1)%
(4) Costs (Millions; $2002)	$86,389	$86,909	$520	0.6%	0.5%
(4a) Fuel Cost	$48,097	$48,182	$85	0.2%	0.0%
(4b) Variable O&M	$7,828	$7,825	($4)	0.0%	0.0%
(4c) Fixed O&M	$23,643	$24,012	$369	1.6%	1.8%
(4d) Capital Cost	$6,821	$6,890	$69	1.0%	0.3%
(5) Pre-Tax Income (Millions; $2002)	$67,629	$67,037	($592)	(0.9)%	(1.0)%
(6) Variable Production Costs ($2002/MWh)	$13.77	$13.79	$0.02	0.1%	0.0%
East Central Area Reliability Coordination Agreement (ECAR)					
(1a) Energy Price ($2002/MWh)	$22.66	$23.01	$0.35	1.5%	0.3%
(1b) Capacity Price ($2002/KW)	$78.35	$78.01	($0.34)	(0.4)%	0.1%
(2) Total Generation (GWh)	649,365	646,400	(2,965)	(0.5)%	(0.2)%
(3) Total Revenues (Millions; $2002)	$23,972	$24,091	$119	0.5%	0.1%
(4) Costs (Millions; $2002)	$12,731	$12,771	$41	0.3%	0.7%
(4a) Fuel Cost	$6,619	$6,576	($43)	(0.6)%	(0.1)%
(4b) Variable O&M	$1,579	$1,574	($5)	(0.3)%	(0.1)%
(4c) Fixed O&M	$3,569	$3,661	$91	2.6%	2.7%
(4d) Capital Cost	$964	$961	($3)	(0.3)%	(0.3)%
(5) Pre-Tax Income (Millions; $2002)	$11,241	$11,320	$78	0.7%	(0.8)%
(6) Variable Production Costs ($2002/MWh)	$12.62	$12.61	($0.02)	(0.1)%	0.1%

Table B3-7: Market-Level Impacts of the Final Rule (NERC 2008 and 2010)

Economic Measures	EPA Base Case	Final Rule	Difference	% Change	% Change 2010
Electric Reliability Council of Texas (ERCOT)					
(1a) Energy Price ($2002/MWh)	$29.98	$30.12	$0.14	0.5%	5.8%
(1b) Capacity Price ($2002/KW)	$0.00	$0.00	$0.00	0.0%	(65.7)%
(2) Total Generation (GWh)	325,835	325,835	0	0.0%	(0.1)%
(3) Total Revenues (Millions; $2002)	$9,768	$9,813	$45	0.5%	(1.2)%
(4) Costs (Millions; $2002)	$7,728	$7,766	$38	0.5%	0.4%
(4a) Fuel Cost	$5,211	$5,205	($6)	(0.1)%	(0.1)%
(4b) Variable O&M	$673	$672	($1)	(0.2)%	0.2%
(4c) Fixed O&M	$1,696	$1,714	$18	1.1%	1.4%
(4d) Capital Cost	$148	$175	$27	18.5%	4.1%
(5) Pre-Tax Income (Millions; $2002)	$2,040	$2,048	$7	0.4%	(5.6)%
(6) Variable Production Costs ($2002/MWh)	$18.06	$18.04	($0.02)	(0.1)%	0.0%
Florida Reliability Coordinating Council (FRCC)					
(1a) Energy Price ($2002/MWh)	$30.18	$30.38	$0.20	0.7%	0.6%
(1b) Capacity Price ($2002/KW)	$63.07	$62.64	($0.43)	(0.7)%	(2.6)%
(2) Total Generation (GWh)	186,234	186,200	(34)	0.0%	(0.1)%
(3) Total Revenues (Millions; $2002)	$8,719	$8,734	$15	0.2%	(0.3)%
(4) Costs (Millions; $2002)	$5,349	$5,386	$37	0.7%	0.7%
(4a) Fuel Cost	$3,129	$3,150	$22	0.7%	0.2%
(4b) Variable O&M	$354	$355	$1	0.3%	0.4%
(4c) Fixed O&M	$1,172	$1,193	$20	1.7%	2.8%
(4d) Capital Cost	$694	$688	($6)	(0.8)%	(0.8)%
(5) Pre-Tax Income (Millions; $2002)	$3,370	$3,348	($22)	(0.7)%	(3.0)%
(6) Variable Production Costs ($2002/MWh)	$18.70	$18.83	$0.13	0.7%	0.4%
Mid-Atlantic Area Council (MAAC)					
(1a) Energy Price ($2002/MWh)	$26.82	$27.12	$0.30	1.1%	0.1%
(1b) Capacity Price ($2002/KW)	$73.68	$73.85	$0.17	0.2%	(0.3)%
(2) Total Generation (GWh)	274,753	275,349	596	0.2%	0.6%
(3) Total Revenues (Millions; $2002)	$12,024	$12,133	$108	0.9%	0.4%
(4) Costs (Millions; $2002)	$5,985	$6,047	$62	1.0%	1.3%
(4a) Fuel Cost	$2,920	$2,941	$20	0.7%	1.1%
(4b) Variable O&M	$553	$554	$1	0.2%	0.5%
(4c) Fixed O&M	$2,125	$2,160	$35	1.6%	2.0%
(4d) Capital Cost	$386	$392	$6	1.6%	0.9%
(5) Pre-Tax Income (Millions; $2002)	$6,039	$6,086	$46	0.8%	(0.9)%

Table B3-7: Market-Level Impacts of the Final Rule (NERC 2008 and 2010)					
Economic Measures	**EPA Base Case**	**Final Rule**	**Difference**	**% Change**	**% Change 2010**
(6) Variable Production Costs ($2002/MWh)	$12.64	$12.69	$0.05	0.4%	0.4%
Mid-America Interconnected Network (MAIN)					
(1a) Energy Price ($2002/MWh)	$22.68	$22.96	$0.28	1.2%	(0.3)%
(1b) Capacity Price ($2002/KW)	$78.80	$77.97	($0.82)	(1.0)%	0.7%
(2) Total Generation (GWh)	285,282	286,219	937	0.3%	(0.1)%
(3) Total Revenues (Millions; $2002)	$11,208	$11,221	$13	0.1%	(0.1)%
(4) Costs (Millions; $2002)	$5,940	$5,963	$23	0.4%	0.1%
(4a) Fuel Cost	$2,940	$2,960	$20	0.7%	0.1%
(4b) Variable O&M	$589	$593	$3	0.6%	(0.5)%
(4c) Fixed O&M	$1,949	$1,972	$23	1.2%	0.9%
(4d) Capital Cost	$463	$439	($24)	(5.2)%	(1.6)%
(5) Pre-Tax Income (Millions; $2002)	$5,268	$5,258	($10)	(0.2)%	(0.3)%
(6) Variable Production Costs ($2002/MWh)	$12.37	$12.41	$0.04	0.3%	0.1%
Mid-Continent Area Power Pool (MAPP)					
(1a) Energy Price ($2002/MWh)	$22.41	$22.72	$0.32	1.4%	(0.3)%
(1b) Capacity Price ($2002/KW)	$78.32	$78.02	($0.30)	(0.4)%	0.9%
(2) Total Generation (GWh)	179,067	178,742	(325)	(0.2)%	(0.1)%
(3) Total Revenues (Millions; $2002)	$6,756	$6,794	$38	0.6%	0.0%
(4) Costs (Millions; $2002)	$3,353	$3,362	$9	0.3%	0.0%
(4a) Fuel Cost	$1,740	$1,737	($2)	(0.1)%	(0.2)%
(4b) Variable O&M	$366	$365	$0	(0.1)%	(0.5)%
(4c) Fixed O&M	$998	$1,012	$14	1.4%	1.2%
(4d) Capital Cost	$249	$247	($1)	(0.5)%	(2.2)%
(5) Pre-Tax Income (Millions; $2002)	$3,404	$3,432	$28	0.8%	0.1%
(6) Variable Production Costs ($2002/MWh)	$11.76	$11.76	$0.00	0.0%	(0.1)%
Northeast Power Coordinating Council (NPCC)					
(1a) Energy Price ($2002/MWh)	$29.48	$30.35	$0.87	3.0%	(0.1)%
(1b) Capacity Price ($2002/KW)	$68.95	$58.24	($10.71)	(15.5)%	0.0%
(2) Total Generation (GWh)	277,871	277,129	(743)	(0.3)%	(0.4)%
(3) Total Revenues (Millions; $2002)	$12,806	$12,309	($496)	(3.9)%	(0.4)%
(4) Costs (Millions; $2002)	$7,668	$7,710	$43	0.6%	0.2%
(4a) Fuel Cost	$4,459	$4,447	($13)	(0.3)%	(0.9)%
(4b) Variable O&M	$376	$372	($3)	(0.9)%	(1.0)%
(4c) Fixed O&M	$1,779	$1,837	$58	3.3%	3.6%
(4d) Capital Cost	$1,053	$1,054	$0	0.0%	(0.1)%
(5) Pre-Tax Income (Millions; $2002)	$5,138	$4,599	($539)	(10.5)%	(1.9)%

Table B3-7: Market-Level Impacts of the Final Rule (NERC 2008 and 2010)					
Economic Measures	**EPA Base Case**	**Final Rule**	**Difference**	**% Change**	**% Change 2010**
(6) Variable Production Costs ($2002/MWh)	$17.40	$17.39	($0.01)	(0.1)%	(0.5)%
Southeastern Electric Reliability Council (SERC)					
(1a) Energy Price ($2002/MWh)	$25.48	$25.57	$0.10	0.4%	(0.1)%
(1b) Capacity Price ($2002/KW)	$68.91	$68.51	($0.40)	(0.6)%	0.4%
(2) Total Generation (GWh)	924,991	927,191	2,199	0.2%	0.1%
(3) Total Revenues (Millions; $2002)	$36,464	$36,577	$113	0.3%	0.1%
(4) Costs (Millions; $2002)	$19,134	$19,316	$183	1.0%	0.6%
(4a) Fuel Cost	$10,337	$10,376	$39	0.4%	0.1%
(4b) Variable O&M	$1,760	$1,759	$0	0.0%	0.3%
(4c) Fixed O&M	$5,182	$5,253	$70	1.4%	1.5%
(4d) Capital Cost	$1,854	$1,928	$74	4.0%	0.8%
(5) Pre-Tax Income (Millions; $2002)	$17,330	$17,261	($69)	(0.4)%	(0.5)%
(6) Variable Production Costs ($2002/MWh)	$13.08	$13.09	$0.01	0.1%	0.0%
Southwest Power Pool (SPP)					
(1a) Energy Price ($2002/MWh)	$25.17	$25.31	$0.14	0.5%	(0.2)%
(1b) Capacity Price ($2002/KW)	$61.73	$61.15	($0.57)	(0.9)%	0.7%
(2) Total Generation (GWh)	217,634	217,539	(95)	0.0%	0.1%
(3) Total Revenues (Millions; $2002)	$8,503	$8,499	($5)	(0.1)%	0.2%
(4) Costs (Millions; $2002)	$4,214	$4,224	$10	0.2%	0.7%
(4a) Fuel Cost	$2,743	$2,746	$3	0.1%	0.0%
(4b) Variable O&M	$419	$419	$0	0.1%	(0.1)%
(4c) Fixed O&M	$1,031	$1,041	$10	1.0%	1.4%
(4d) Capital Cost	$21	$18	($4)	(17.6)%	14.7%
(5) Pre-Tax Income (Millions; $2002)	$4,289	$4,275	($15)	(0.3)%	(0.4)%
(6) Variable Production Costs ($2002/MWh)	$14.53	$14.55	$0.02	0.1%	(0.1)%
Western Systems Coordinating Council (WSCC)					
(1a) Energy Price ($2002/MWh)	$28.58	$28.71	$0.13	0.5%	0.0%
(1b) Capacity Price ($2002/KW)	$18.17	$17.25	($0.92)	(5.0)%	0.3%
(2) Total Generation (GWh)	739,205	739,797	592	0.1%	0.0%
(3) Total Revenues (Millions; $2002)	$23,797	$23,774	($22)	(0.1)%	0.0%
(4) Costs (Millions; $2002)	$14,287	$14,362	$75	0.5%	0.2%
(4a) Fuel Cost	$7,999	$8,044	$45	0.6%	0.0%
(4b) Variable O&M	$1,160	$1,161	$1	0.1%	0.1%
(4c) Fixed O&M	$4,140	$4,169	$29	0.7%	0.7%
(4d) Capital Cost	$989	$988	($1)	(0.1)%	(0.1)%

Table B3-7: Market-Level Impacts of the Final Rule (NERC 2008 and 2010)					
Economic Measures	EPA Base Case	Final Rule	Difference	% Change	% Change 2010
(5) Pre-Tax Income (Millions; $2002)	$9,509	$9,412	($97)	(1.0)%	(0.5)%
(6) Variable Production Costs ($2002/MWh)	$12.39	$12.44	$0.05	0.4%	0.0%

Source: IPM analysis: Model runs for Section 316(b) NODA Base Case and the final rule (EPA electricity demand assumptions).

Summary of Market Results at the National Level. The results presented in Table B3-7 show that under the final rule downtimes associated with the installation of compliance technologies will not lead to significant changes in economic impacts compared to the results for 2010 (which represents the post-compliance scenario in which no facilities experience downtimes). There will be an 0.2 percent increase in fuel costs in 2008, leading to an increase in variable production cost per MWh of 0.1 percent. In addition, the rise in capital costs is estimated to be somewhat higher in 2008 than in 2010.

Summary of Market Results at the Regional Level. The following discussion highlights differences in the analysis results between 2010 and 2008:

- In **FRCC** and **SERC**, most impact results for 2008 and 2010 are either the same or slightly lower in 2008. **FRCC** is estimated to experience a smaller decrease in capacity prices in 2008 which will result in higher revenues and a smaller loss in pre-tax income compared to 2010. In **SERC**, energy prices and generation are estimated to increase more in 2008 than 2010, leading to an increase in revenues and a reduction in pre-tax income loss.

- **ECAR**, **MACC**, and **MAPP** are estimated to experience increases in energy prices between 1.1 and 1.5 percent in 2008. These increases will lead to higher revenues and increases in pre-tax income of between 0.7 and 0.8 percent.

- **NPCC**, and **WSCC** are both estimated to experience increases in energy prices under the final rule in 2008. However, capacity prices are estimated to decrease, leading to a reduction in revenues and pre-tax income. In **WSCC**, fuel costs will increase by 0.6 percent, resulting in an 0.4 percent increase in variable production costs per Mwh.

- **MAIN** is estimated to experience increases in energy prices and a decrease in capacity prices under the final rule in 2008, similar to **NPCC** and **WSCC**. However, generation is estimated to increase rather than decrease in 2008 as compared to 2010, resulting in higher revenues and a smaller decrease in pre-tax income.

- **ERCOT** is estimated to experience substantially lower price effects in 2008 compared to 2010. The increase in energy prices will be 0.5 percent compared to 5.8 percent in 2010. Capacity prices in 2008 are zero in both the base case and under the final rule as a result of excess capacity in the region (note that there are no new capacity additions in ERCOT in 2008). ERCOT is also estimated to experience an increase in revenues and an increase in pre-tax income compared to 2010.

- In **SPP**, energy prices under the final rule are estimated to increase by 0.5 percent in 2008 while capacity prices will fall, resulting in a 0.1 percent reduction in revenues. The only other notable difference in results compared to 2010 is a relatively large percentage reduction in capital costs in 2008. This is the result of a minor delay in investment in new capacity additions under the final rule: approximately 120 MW of capacity that is projected to be built in 2008 in the base case is postponed until 2010 under the final rule. As a result, 2008 sees a reduction in capital costs while 2010 sees an increase. Overall, the reduction in capital costs in 2008 comprises less than 0.1 percent of total base case cost.

B3-5 Uncertainties and Limitations

There are uncertainties associated with EPA's analysis of the electric power market and the economic impacts of the final rule:

- ***Demand for electricity:*** The IPM assumes that electricity demand at the national level 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, electricity demand 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 final rule. 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 final rule. As described in Section B3-4 above, the price increases associated with the final rule in most NERC regions are relatively small. EPA therefore concludes that the assumption of inelastic demand-responses to changes in prices is reasonable.

- ***International imports:*** The IPM also assumes that imports from Canada and Mexico would not change between the base case and the analyzed policy options. 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. On the other hand, holding imports fixed may understate effects on marginal domestic units, which may be displaced by increased imports. However, EPA concludes that fixed imports do not materially affect the results of the analyses. In 2010 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, 6 percent in NPCC, and 1.5 percent in WSCC).

- ***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. Repowering in the IPM typically consists of the conversion of existing oil/gas or coal capacity to new combined-cycle capacity. The modeling assumption is that each one MW of existing capacity is replaced by two MW of repowered capacity. This change in plant type and size might lead to a change in intake flow and potentially to different compliance requirements and costs. Since combined-cycle facilities require substantially less cooling water than other oil/gas or coal facilities, the effect of repowering is likely to be a reduction in cooling water requirements (even considering the doubling of the plant's capacity). As a result, not allowing the model to adjust the compliance response or cost is likely to lead to a conservative estimate of compliance costs and potential economic impacts from the final rule.

- ***Downtime associated with installation of compliance technologies:*** EPA estimates that the installation of several compliance technologies would require the steam electric generators of facilities that are projected to install such technologies to be off-line. Downtime is estimated to range between two and eleven weeks, depending on the technology. Generator downtime is estimated to occur during the year when a facility complies with the final rule. Since the years that are mapped into a run year are assumed to have the same characteristics as the run year itself, generator downtimes were applied as an average over the years that are mapped into each model run year. For example, years 2005 to 2009 are all mapped into 2008. Therefore, a facility with a downtime in 2008 was modeled as if 1/5th of its downtime occurred in each year between 2005 and 2009. A potential drawback of this approach of averaging downtimes over the mapped years is that the snapshot of the effect of downtimes during the model run year is the average effect; this approach does not model potential worst case effects of above-average amounts of capacity being down in any one NERC region during any one year.

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Chapter B3 - Appendix A

Introduction

Chapter Contents

This appendix presents additional electricity market model results for the final Phase II rule, using alternative assumptions about future growth in electricity demand. In the analyses presented in the body of this chapter, electricity demand was based on the Annual Energy Outlook 2001 (AEO2001) forecast adjusted to account for demand reductions resulting from implementation of the Climate Change Action Plan (CCAP). The analyses presented in this appendix are based on the unadjusted AEO2001 forecasts.

B3-A.1 Alternative Analysis Results

The following subsections present results for (1) the entire market (i.e., all generators including facilities that are in-scope and facilities that are out-of-scope of Phase II regulation); (2) the in-scope Phase II facilities as a group; and (3) individual Phase II facilities. The tables are equivalent to the tables for the final rule presented in the section B3-4, except for the change in electricity demand assumptions. In addition, Tables B3-A-2 and B3-A-4 present a comparison of the changes as a result of the final rule under the two different electricity demand assumptions.

B3-A.1-1 Market Analysis for 2010 – AEO Assumptions

This section presents the results of the IPM analysis for all facilities modeled by the IPM. The market-level analysis includes results for all generators located in each North American Electric Reliability Council (NERC) region including facilities that are in-scope and facilities that are out-of-scope of Phase II regulation.

Table B3-A-1 below (equivalent to Table B3-4) presents seven measures of market-level impacts associated with the final rule: (1) capacity changes, including changes in existing capacity, new additions, repowering additions, and closures; (2) electricity price changes, including changes in energy prices and capacity prices; (3) generation changes; (4) revenue changes; (5) cost changes, including changes in fuel costs, variable O&M costs, fixed O&M costs, and capital costs; (6) changes in pre-tax income, defined as revenues minus total costs; and (7) changes in variable production costs per MWh. For each measure, the Table presents the results for the base case and the final rule, the absolute difference between the two cases, and the percentage difference by NERC region. A detailed description of each of the impact measures is presented in Section B3-3.1 of this chapter.

Table B3-A-1: Market-Level Impacts of the Final Rule (by NERC Region; 2010)

Economic Measures	AEO Base Case	Final Rule	Difference	% Change
National Totals				
(1) Total Domestic Capacity (MW)	947,406	947,434	28	0.0%
(1a) Existing	788,986	788,046	(940)	(0.1)%
(1b) New Additions	133,162	133,214	52	0.0%
(1c) Repowering Additions	25,258	26,174	916	3.6%
(1d) Closures	10,203	10,696	493	4.8%
(2a) Energy Prices ($2002/MWh)	n/a	n/a	n/a	n/a
(2b) Capacity Prices ($2002/KW/yr)	n/a	n/a	n/a	n/a
(3) Generation (GWh)	4,400,321	4,400,761	440	0.0%

Table B3-A-1: Market-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	**AEO Base Case**	**Final Rule**	**Difference**	**% Change**
(4) Revenues (Millions; $2002)	$156,989	$156,991	$2	0.0%
(5) Costs (Millions; $2002)	$98,824	$99,243	$419	0.4%
(5a) Fuel Cost	$53,473	$53,471	($3)	0.0%
(5b) Variable O&M	$8,320	$8,325	$5	0.1%
(5c) Fixed O&M	$24,484	$24,862	$377	1.5%
(5d) Capital Cost	$12,547	$12,586	$39	0.3%
(6) Pre-Tax Income (Millions; $2002)	$58,165	$57,748	($417)	(0.7)%
(7) Variable Production Costs ($/MWh)	$14.04	$14.04	$0.00	0.0%
East Central Area Reliability Coordination Agreement (ECAR)				
(1) Total Domestic Capacity (MW)	127,332	127,098	(233)	(0.2)%
(1a) Existing	110,034	110,044	10	0.0%
(1b) New Additions	17,228	16,984	(244)	(1.4)%
(1c) Repowering Additions	70	70	0	0.0%
(1d) Closures	0	0	0	0.0%
(2a) Energy Prices ($2002/MWh)	$24.82	$24.82	$0.01	0.0%
(2b) Capacity Prices ($2002/KW/yr)	$54.17	$54.18	$0.00	0.0%
(3) Generation (GWh)	680,905	681,417	511	0.1%
(4) Revenues (Millions; $2002)	$23,781	$23,786	$5	0.0%
(5) Costs (Millions; $2002)	$13,854	$13,939	$85	0.6%
(5a) Fuel Cost	$6,963	$6,984	$21	0.3%
(5b) Variable O&M	$1,659	$1,658	($1)	(0.1)%
(5c) Fixed O&M	$3,658	$3,751	$93	2.5%
(5d) Capital Cost	$1,573	$1,546	($28)	(1.8)%
(6) Pre-Tax Income (Millions; $2002)	$9,927	$9,847	($80)	(0.8)%
(7) Variable Production Costs ($/MWh)	$12.66	$12.68	$0.02	0.2%
Electric Reliability Council of Texas (ERCOT)				
(1) Total Domestic Capacity (MW)	80,472	80,473	1	0.0%
(1a) Existing	69,845	69,398	(448)	(0.6)%
(1b) New Additions	5,202	4,756	(446)	(8.6)%
(1c) Repowering Additions	5,425	6,319	895	16.5%
(1d) Closures	0	0	0	0.0%
(2a) Energy Prices ($2002/MWh)	$27.20	$27.55	$0.35	1.3%
(2b) Capacity Prices ($2002/KW/yr)	$34.13	$32.33	($1.81)	(5.3)%
(3) Generation (GWh)	362,415	362,415	0	0.0%
(4) Revenues (Millions; $2002)	$12,605	$12,581	($24)	(0.2)%
(5) Costs (Millions; $2002)	$9,054	$9,089	$36	0.4%
(5a) Fuel Cost	$5,760	$5,755	($5)	(0.1)%
(5b) Variable O&M	$719	$718	($1)	(0.2)%
(5c) Fixed O&M	$1,783	$1,805	$22	1.2%
(5d) Capital Cost	$791	$811	$20	2.5%

Table B3-A-1: Market-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	**AEO Base Case**	**Final Rule**	**Difference**	**% Change**
(6) Pre-Tax Income (Millions; $2002)	$3,551	$3,492	($59)	(1.7)%
(7) Variable Production Costs ($/MWh)	$17.88	$17.86	($0.02)	(0.1)%
Florida Reliability Coordinating Council (FRCC)				
(1) Total Domestic Capacity (MW)	53,831	53,832	0	0.0%
(1a) Existing	39,238	39,239	2	0.0%
(1b) New Additions	14,594	14,592	(2)	0.0%
(1c) Repowering Additions	0	0	0	0.0%
(1d) Closures	812	812	0	0.0%
(2a) Energy Prices ($2002/MWh)	$30.19	$30.34	$0.16	0.5%
(2b) Capacity Prices ($2002/KW/yr)	$37.42	$36.49	($0.94)	(2.5)%
(3) Generation (GWh)	204,711	204,697	(13)	0.0%
(4) Revenues (Millions; $2002)	$8,194	$8,175	($19)	(0.2)%
(5) Costs (Millions; $2002)	$6,104	$6,146	$42	0.7%
(5a) Fuel Cost	$3,472	$3,477	$4	0.1%
(5b) Variable O&M	$393	$396	$3	0.8%
(5c) Fixed O&M	$1,237	$1,272	$35	2.8%
(5d) Capital Cost	$1,001	$1,000	($1)	(0.1)%
(6) Pre-Tax Income (Millions; $2002)	$2,090	$2,030	($61)	(2.9)%
(7) Variable Production Costs ($/MWh)	$18.88	$18.92	$0.04	0.2%
Mid-Atlantic Area Council (MAAC)				
(1) Total Domestic Capacity (MW)	68,838	68,782	(56)	(0.1)%
(1a) Existing	57,461	57,461	0	0.0%
(1b) New Additions	9,719	9,662	(56)	(0.6)%
(1c) Repowering Additions	1,658	1,658	0	0.0%
(1d) Closures	1,725	1,725	0	0.0%
(2a) Energy Prices ($2002/MWh)	$27.99	$28.01	$0.02	0.1%
(2b) Capacity Prices ($2002/KW/yr)	$51.00	$50.90	($0.10)	(0.2)%
(3) Generation (GWh)	299,588	299,044	(543)	(0.2)%
(4) Revenues (Millions; $2002)	$11,894	$11,875	($19)	(0.2)%
(5) Costs (Millions; $2002)	$7,085	$7,103	$18	0.3%
(5a) Fuel Cost	$3,482	$3,463	($19)	(0.6)%
(5b) Variable O&M	$596	$595	($1)	(0.1)%
(5c) Fixed O&M	$2,123	$2,161	$39	1.8%
(5d) Capital Cost	$884	$884	($1)	(0.1)%
(6) Pre-Tax Income (Millions; $2002)	$4,809	$4,772	($37)	(0.8)%
(7) Variable Production Costs ($/MWh)	$13.61	$13.57	($0.04)	(0.3)%
Mid-America Interconnected Network (MAIN)				
(1) Total Domestic Capacity (MW)	63,946	63,909	(38)	(0.1)%
(1a) Existing	53,659	53,166	(493)	(0.9)%

Table B3-A-1: Market-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	**AEO Base Case**	**Final Rule**	**Difference**	**% Change**
(1b) New Additions	10,288	10,743	455	4.4%
(1c) Repowering Additions	0	0	0	0.0%
(1d) Closures	3,083	3,576	493	16.0%
(2a) Energy Prices ($2002/MWh)	$23.96	$23.95	($0.01)	0.0%
(2b) Capacity Prices ($2002/KW/yr)	$54.16	$54.80	$0.64	1.2%
(3) Generation (GWh)	303,096	302,009	(1,087)	(0.4)%
(4) Revenues (Millions; $2002)	$10,721	$10,729	$8	0.1%
(5) Costs (Millions; $2002)	$6,568	$6,570	$2	0.0%
(5a) Fuel Cost	$3,196	$3,213	$18	0.6%
(5b) Variable O&M	$627	$625	($2)	(0.3)%
(5c) Fixed O&M	$1,994	$1,977	($18)	(0.9)%
(5d) Capital Cost	$751	$755	$4	0.5%
(6) Pre-Tax Income (Millions; $2002)	$4,153	$4,159	$6	0.1%
(7) Variable Production Costs ($/MWh)	$12.61	$12.71	$0.10	0.8%
Mid-Continent Area Power Pool (MAPP)				
(1) Total Domestic Capacity (MW)	38,477	38,477	0	0.0%
(1a) Existing	32,672	32,672	0	0.0%
(1b) New Additions	5,806	5,806	0	0.0%
(1c) Repowering Additions	0	0	0	0.0%
(1d) Closures	476	476	0	0.0%
(2a) Energy Prices ($2002/MWh)	$22.94	$22.77	($0.17)	(0.7)%
(2b) Capacity Prices ($2002/KW/yr)	$53.64	$54.88	$1.24	2.3%
(3) Generation (GWh)	195,033	195,262	229	0.1%
(4) Revenues (Millions; $2002)	$6,512	$6,532	$19	0.3%
(5) Costs (Millions; $2002)	$3,894	$3,915	$20	0.5%
(5a) Fuel Cost	$1,963	$1,962	($1)	0.0%
(5b) Variable O&M	$398	$398	$1	0.2%
(5c) Fixed O&M	$1,044	$1,060	$16	1.5%
(5d) Capital Cost	$490	$494	$5	0.9%
(6) Pre-Tax Income (Millions; $2002)	$2,618	$2,617	($1)	0.0%
(7) Variable Production Costs ($/MWh)	$12.10	$12.09	($0.01)	(0.1)%
Northeast Power Coordinating Council (NPCC)				
(1) Total Domestic Capacity (MW)	76,114	76,154	40	0.1%
(1a) Existing	59,678	59,691	13	0.0%
(1b) New Additions	5,882	5,935	53	0.9%
(1c) Repowering Additions	10,554	10,528	(25)	(0.2)%
(1d) Closures	4,107	4,107	0	0.0%
(2a) Energy Prices ($2002/MWh)	$30.65	$30.67	$0.02	0.1%
(2b) Capacity Prices ($2002/KW/yr)	$48.65	$48.42	($0.23)	(0.5)%
(3) Generation (GWh)	302,155	302,422	267	0.1%

Table B3-A-1: Market-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	**AEO Base Case**	**Final Rule**	**Difference**	**% Change**
(4) Revenues (Millions; $2002)	$12,689	$12,688	($2)	0.0%
(5) Costs (Millions; $2002)	$8,761	$8,822	$61	0.7%
(5a) Fuel Cost	$5,116	$5,110	($6)	(0.1)%
(5b) Variable O&M	$402	$400	($2)	(0.6)%
(5c) Fixed O&M	$1,831	$1,895	$64	3.5%
(5d) Capital Cost	$1,412	$1,417	$5	0.3%
(6) Pre-Tax Income (Millions; $2002)	$3,928	$3,865	($62)	(1.6)%
(7) Variable Production Costs ($/MWh)	$18.26	$18.22	($0.04)	(0.2)%
Southeastern Electric Reliability Council (SERC)				
(1) Total Domestic Capacity (MW)	207,945	208,286	341	0.2%
(1a) Existing	164,552	164,552	0	0.0%
(1b) New Additions	43,393	43,734	341	0.8%
(1c) Repowering Additions	0	0	0	0.0%
(1d) Closures	0	0	0	0.0%
(2a) Energy Prices ($2002/MWh)	$25.81	$25.81	$0.00	0.0%
(2b) Capacity Prices ($2002/KW/yr)	$47.48	$47.50	$0.03	0.1%
(3) Generation (GWh)	1,012,116	1,013,119	1,002	0.1%
(4) Revenues (Millions; $2002)	$35,984	$36,031	$48	0.1%
(5) Costs (Millions; $2002)	$22,345	$22,457	$112	0.5%
(5a) Fuel Cost	$11,804	$11,792	($12)	(0.1)%
(5b) Variable O&M	$1,870	$1,876	$6	0.3%
(5c) Fixed O&M	$5,411	$5,492	$81	1.5%
(5d) Capital Cost	$3,260	$3,297	$37	1.1%
(6) Pre-Tax Income (Millions; $2002)	$13,638	$13,574	($64)	(0.5)%
(7) Variable Production Costs ($/MWh)	$13.51	$13.49	($0.02)	(0.1)%
Southwest Power Pool (SPP)				
(1) Total Domestic Capacity (MW)	52,670	52,644	(26)	0.0%
(1a) Existing	48,956	48,956	0	0.0%
(1b) New Additions	3,714	3,688	(26)	(0.7)%
(1c) Repowering Additions	0	0	0	0.0%
(1d) Closures	0	0	0	0.0%
(2a) Energy Prices ($2002/MWh)	$24.92	$24.98	$0.06	0.2%
(2b) Capacity Prices ($2002/KW/yr)	$45.59	$45.20	($0.39)	(0.8)%
(3) Generation (GWh)	233,472	233,542	70	0.0%
(4) Revenues (Millions; $2002)	$8,216	$8,209	($7)	(0.1)%
(5) Costs (Millions; $2002)	$4,742	$4,751	$9	0.2%
(5a) Fuel Cost	$2,944	$2,943	($1)	0.0%
(5b) Variable O&M	$430	$431	$1	0.2%
(5c) Fixed O&M	$1,076	$1,088	$12	1.1%
(5d) Capital Cost	$292	$289	($3)	(1.0)%

Table B3-A-1: Market-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	**AEO Base Case**	**Final Rule**	**Difference**	**% Change**
(6) Pre-Tax Income (Millions; $2002)	$3,474	$3,458	($16)	(0.5)%
(7) Variable Production Costs ($/MWh)	$14.45	$14.45	($0.01)	0.0%
Western Systems Coordinating Council (WSCC)				
(1) Total Domestic Capacity (MW)	177,780	177,780	0	0.0%
(1a) Existing	152,891	152,868	(23)	0.0%
(1b) New Additions	17,337	17,314	(24)	(0.1)%
(1c) Repowering Additions	7,552	7,599	47	0.6%
(1d) Closures	0	0	0	0.0%
(2a) Energy Prices ($2002/MWh)	$27.65	$27.66	$0.01	0.0%
(2b) Capacity Prices ($2002/KW/yr)	$25.05	$24.99	($0.06)	(0.2)%
(3) Generation (GWh)	806,830	806,834	4	0.0%
(4) Revenues (Millions; $2002)	$26,393	$26,384	($9)	0.0%
(5) Costs (Millions; $2002)	$16,417	$16,451	$34	0.2%
(5a) Fuel Cost	$8,772	$8,771	($1)	0.0%
(5b) Variable O&M	$1,226	$1,227	$1	0.1%
(5c) Fixed O&M	$4,327	$4,360	$33	0.8%
(5d) Capital Cost	$2,091	$2,093	$1	0.1%
(6) Pre-Tax Income (Millions; $2002)	$9,976	$9,933	($43)	(0.4)%
(7) Variable Production Costs ($/MWh)	$12.39	$12.39	$0.00	0.0%

Source: IPM analysis: Model runs for Section 316(b) NODA Base Case and the final rule (AEO electricity demand assumptions).

Table B2-A-2 repeats some of the information presented in Tables B3-4 and B3-A-1 to facilitate a comparison of the results using the two different electricity demand assumptions. The columns labeled "EPA" represent the results based on EPA electricity demand assumptions; the columns labeled"AEO" represent the results based on AEO electricity demand assumptions. The table highlights differences between the two cases of greater than or equal to 0.5 percent with bold font and pale blue shading. For a description of the metrics presented in this table, please refer to section B3-3.1.

Table B3-A-2: Comparison of Market-Level Impacts of the Final Rule (2010)

NERC Region	Baseline Capacity (MW)		Incremental Capacity Closures (MW)		Closures as % of Baseline Capacity		Change in Variable Production Cost per MWh		Change in Energy Price per MWh		Change in Pre-Tax Income	
	EPA	AEO	EPA	AEO	EPA	AEO	EPA	AEO	EPA	AEO	EPA	AEO
ECAR	118,529	127,332	0	0	0.0%	0.0%	0.1%	0.2%	0.3%	0.0%	(0.8)%	(0.8)%
ERCOT	75,290	80,472	0	0	0.0%	0.0%	0.0%	(0.1)%	**5.8%**	**1.3%**	**(5.6)%**	**(1.7)%**
FRCC	50,324	53,831	0	0	0.0%	0.0%	0.4%	0.2%	0.6%	0.5%	(3.0)%	(2.9)%
MAAC	63,784	68,838	0	0	0.0%	0.0%	**0.4%**	**(0.3)%**	0.1%	0.1%	(0.9)%	(0.8)%
MAIN	59,494	63,946	**94**	**493**	**0.2%**	**0.8%**	**0.1%**	**0.8%**	(0.3)%	0.0%	(0.3)%	0.1%
MAPP	35,835	38,477	0	0	0.0%	0.0%	(0.1)%	(0.1)%	(0.3)%	(0.7)%	0.1%	0.0%
NPCC	72,477	76,114	0	0	0.0%	0.0%	(0.5)%	(0.2)%	(0.1)%	0.1%	(1.9)%	(1.6)%
SERC	194,485	207,945	0	0	0.0%	0.0%	0.0%	(0.1)%	(0.1)%	0.0%	(0.5)%	(0.5)%
SPP	49,948	52,670	0	0	0.0%	0.0%	(0.1)%	0.0%	(0.2)%	0.2%	(0.4)%	(0.5)%
WSCC	167,748	177,780	58	0	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	(0.5)%	(0.4)%
Total	**887,915**	**947,406**	**152**	**493**	**0.0%**	**0.1%**	**0.0%**	**0.0%**	**n/a**	**n/a**	**(1.0)%**	**(0.7)%**

Source: *IPM analysis: Model runs for Section 316(b) NODA Base Case and the final rule (EPA and AEO electricity demand assumptions).*

The comparison of the two market-level analyses of the final rule, using the two different electricity demand assumptions, shows only minor differences in the results. It should also be noted that the direction of the differences is not systematic, i.e., in some cases, impacts are greater under the AEO assumptions; in other cases, impacts are greater under the EPA assumptions.

- **Incremental capacity closures** are 341 MW higher under the AEO assumptions than under the EPA assumptions. This corresponds to less than 0.04 percent of total baseline capacity under either base case. **MAIN** is estimated to experience 493 MW of capacity closure under the AEO assumptions, compared to 94 under the EPA assumptions. Conversely, **WSCC** is estimated to experience 58 MW of capacity closure under the EPA assumptions and no closures under the AEO assumptions.

- MAIN is the only region with a difference in **incremental closures as a percentage of baseline capacity** under the two assumptions: under the AEO assumptions closures are approximately 0.6 percent higher than under the EPA assumptions.

- **Variable production costs per MWh** in MAAC increase by 0.4 percent under the EPA assumptions and fall by 0.3 percent under the AEO assumptions, a difference of 0.7 percentage points. Conversely, in MAIN, variable production cost per MWh increase more under the AEO assumptions than under the EPA assumptions (0.8 compared to 0.1 percent).

- **Energy price** increases in ERCOT are smaller under the AEO assumptions than under the EPA assumptions (1.3 percent compared to 5.8 percent, a difference of 4.5 percentage points).

- In ERCOT, facilities experience a much larger reduction in **pre-tax income** under the EPA assumptions than under the AEO assumptions (5.6 percent compared to 1.7 percent, a difference of 3.9 percentage points).

- **For all other measures and regions, the results under the two different electricity demand assumptions are within 0.5 percent of each other.**

B3-A.1-2 Analysis of Phase II Facilities for 2010 – AEO Assumptions

This section presents the results of the IPM analysis for the Phase II facilities that are modeled by the IPM. Eight of the 535 Phase II facilities are closures in the base case and under the final rule. These facilities are not represented in the results described in this section.

EPA used the IPM results from model run year 2010 to analyze impacts on Phase II facilities at two levels: (1) potential changes in the economic and operational characteristics of the in-scope Phase II facilities as a group and (2) potential changes to individual facilities within the group of in-scope Phase II facilities.

a. In-scope Phase II facilities as a group

The analysis of the in-scope Phase II facilities as a group is largely similar to the market-level analysis, except that the base case and policy option totals only include the economic activities of the 535 in-scope Phase II facilities represented by the IPM. Table B3-A-3 below (equivalent to Table B3-5) presents six impact measures for the group of Phase II facilities: (1) capacity changes, including changes in the number and capacity of closure facilities; (2) generation changes; (3) revenue changes; (4) cost changes, including changes in fuel costs, variable O&M costs, fixed O&M costs, and capital costs; (5) changes in pre-tax income; and (6) changes in variable production costs per MWh of generation, where variable production cost is defined as the sum of fuel cost and variable O&M cost. For each measure, the table presents the results for the base case and the final rule, the absolute difference between the two cases, and the percentage difference.

Table B3-A-3: Facility-Level Impacts of the Final Rule (by NERC Region; 2010)

Economic Measures	AEO Base Case	Final Rule	Difference	% Change
National Totals				
(1) Total Domestic Capacity (MW)	438,510	438,004	(506)	(0.1)%
(1a) Closures - Number of Facilities	8	8	0	0.0%
(1b) Closures - Capacity (MW)	10,204	10,697	493	4.8%
(2) Generation (GWh)	2,359,403	2,351,936	(7,466)	(0.3)%
(3) Revenues (Millions; $2002)	$81,220	$80,964	($256)	(0.3)%
(4) Costs (Millions; $2002)	$49,368	$49,544	$175	0.4%
(4a) Fuel Cost	$25,612	$25,465	($147)	(0.6)%
(4b) Variable O&M	$5,250	$5,245	($5)	(0.1)%
(4c) Fixed O&M	$15,612	$15,977	$365	2.3%
(4d) Capital Cost	$2,895	$2,857	($38)	(1.3)%
(5) Pre-Tax Income (Millions; $2002)	$31,851	$31,420	($431)	(1.4)%
(6) Variable Production Costs ($2002/MWh)	$13.08	$13.06	($0.02)	(0.2)%
East Central Area Reliability Coordination Agreement (ECAR)				
(1) Total Domestic Capacity (MW)	82,281	82,292	10	0.0%
(1a) Closures - Number of Facilities	0	0	0	0.0%
(1b) Closures - Capacity (MW)	1	1	0	0.0%
(2) Generation (GWh)	532,207	532,268	61	0.0%
(3) Revenues (Millions; $2002)	$17,524	$17,530	$6	0.0%
(4) Costs (Millions; $2002)	$9,924	$10,018	$94	1.0%
(4a) Fuel Cost	$5,207	$5,221	$15	0.3%
(4b) Variable O&M	$1,302	$1,301	($1)	(0.1)%
(4c) Fixed O&M	$2,981	$3,074	$93	3.1%
(4d) Capital Cost	$434	$421	($12)	(2.9)%
(5) Pre-Tax Income (Millions; $2002)	$7,600	$7,512	($88)	(1.2)%

Table B3-A-3: Facility-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	**AEO Base Case**	**Final Rule**	**Difference**	**% Change**
(6) Variable Production Costs ($2002/MWh)	$12.23	$12.25	$0.02	0.2%
Electric Reliability Council of Texas (ERCOT)				
(1) Total Domestic Capacity (MW)	44,413	44,452	39	0.1%
(1a) Closures - Number of Facilities	0	0	0	0.0%
(1b) Closures - Capacity (MW)	0	0	0	0.0%
(2) Generation (GWh)	160,614	159,032	(1,582)	(1.0)%
(3) Revenues (Millions; $2002)	$5,919	$5,842	($76)	(1.3)%
(4) Costs (Millions; $2002)	$4,026	$4,009	($17)	(0.4)%
(4a) Fuel Cost	$2,186	$2,137	($49)	(2.2)%
(4b) Variable O&M	$421	$417	($3)	(0.8)%
(4c) Fixed O&M	$1,193	$1,218	$25	2.1%
(4d) Capital Cost	$227	$237	$10	4.3%
(5) Pre-Tax Income (Millions; $2002)	$1,892	$1,833	($59)	(3.1)%
(6) Variable Production Costs ($2002/MWh)	$16.23	$16.06	($0.17)	(1.0)%
Florida Reliability Coordinating Council (FRCC)				
(1) Total Domestic Capacity (MW)	27,513	27,514	2	0.0%
(1a) Closures - Number of Facilities	0	0	0	0.0%
(1b) Closures - Capacity (MW)	812	812	0	0.0%
(2) Generation (GWh)	80,925	80,927	3	0.0%
(3) Revenues (Millions; $2002)	$3,445	$3,431	($14)	(0.4)%
(4) Costs (Millions; $2002)	$2,002	$2,045	$43	2.2%
(4a) Fuel Cost	$1,093	$1,101	$8	0.7%
(4b) Variable O&M	$197	$200	$3	1.6%
(4c) Fixed O&M	$682	$716	$34	5.0%
(4d) Capital Cost	$30	$28	($2)	(5.6)%
(5) Pre-Tax Income (Millions; $2002)	$1,443	$1,386	($57)	(4.0)%
(6) Variable Production Costs ($2002/MWh)	$15.94	$16.07	$0.13	0.8%
Mid-Atlantic Area Council (MAAC)				
(1) Total Domestic Capacity (MW)	35,482	35,482	0	0.0%
(1a) Closures - Number of Facilities	1	1	0	0.0%
(1b) Closures - Capacity (MW)	1,725	1,725	0	0.0%
(2) Generation (GWh)	182,096	181,226	(870)	(0.5)%
(3) Revenues (Millions; $2002)	$6,846	$6,825	($21)	(0.3)%
(4) Costs (Millions; $2002)	$3,894	$3,907	$13	0.3%
(4a) Fuel Cost	$1,766	$1,741	($25)	(1.4)%
(4b) Variable O&M	$375	$374	($1)	(0.3)%
(4c) Fixed O&M	$1,587	$1,626	$38	2.4%
(4d) Capital Cost	$166	$166	$0	0.0%
(5) Pre-Tax Income (Millions; $2002)	$2,952	$2,918	($34)	(1.1)%

Table B3-A-3: Facility-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	**AEO Base Case**	**Final Rule**	**Difference**	**% Change**
(6) Variable Production Costs ($2002/MWh)	$11.76	$11.67	($0.09)	(0.7)%
Mid-America Interconnected Network (MAIN)				
(1) Total Domestic Capacity (MW)	38,606	38,113	(493)	(1.3)%
(1a) Closures - Number of Facilities	2	2	0	0.0%
(1b) Closures - Capacity (MW)	3,083	3,576	493	16.0%
(2) Generation (GWh)	239,552	236,989	(2,563)	(1.1)%
(3) Revenues (Millions; $2002)	$7,705	$7,639	($66)	(0.9)%
(4) Costs (Millions; $2002)	$4,589	$4,529	($60)	(1.3)%
(4a) Fuel Cost	$2,185	$2,174	($11)	(0.5)%
(4b) Variable O&M	$540	$537	($4)	(0.6)%
(4c) Fixed O&M	$1,732	$1,709	($23)	(1.3)%
(4d) Capital Cost	$132	$109	($23)	(17.4)%
(5) Pre-Tax Income (Millions; $2002)	$3,116	$3,110	($6)	(0.2)%
(6) Variable Production Costs ($2002/MWh)	$11.37	$11.44	$0.06	0.6%
Mid-Continent Area Power Pool (MAPP)				
(1) Total Domestic Capacity (MW)	15,749	15,749	0	0.0%
(1a) Closures - Number of Facilities	1	1	0	0.0%
(1b) Closures - Capacity (MW)	476	476	0	0.0%
(2) Generation (GWh)	110,585	110,668	83	0.1%
(3) Revenues (Millions; $2002)	$3,323	$3,327	$4	0.1%
(4) Costs (Millions; $2002)	$2,004	$2,020	$16	0.8%
(4a) Fuel Cost	$1,067	$1,068	$1	0.1%
(4b) Variable O&M	$226	$227	$0	0.2%
(4c) Fixed O&M	$597	$612	$15	2.4%
(4d) Capital Cost	$114	$114	$0	0.0%
(5) Pre-Tax Income (Millions; $2002)	$1,319	$1,307	($12)	(0.9)%
(6) Variable Production Costs ($2002/MWh)	$11.70	$11.70	$0.01	0.0%
Northeast Power Coordinating Council (NPCC)				
(1) Total Domestic Capacity (MW)	37,219	37,164	(55)	(0.1)%
(1a) Closures - Number of Facilities	4	4	0	0.0%
(1b) Closures - Capacity (MW)	4,107	4,107	0	0.0%
(2) Generation (GWh)	159,374	157,749	(1,626)	(1.0)%
(3) Revenues (Millions; $2002)	$6,594	$6,532	($63)	(1.0)%
(4) Costs (Millions; $2002)	$4,948	$4,953	$5	0.1%
(4a) Fuel Cost	$2,667	$2,621	($46)	(1.7)%
(4b) Variable O&M	$268	$264	($4)	(1.6)%
(4c) Fixed O&M	$1,238	$1,302	$63	5.1%
(4d) Capital Cost	$774	$766	($8)	(1.1)%
(5) Pre-Tax Income (Millions; $2002)	$1,646	$1,579	($67)	(4.1)%
(6) Variable Production Costs ($2002/MWh)	$18.42	$18.29	($0.13)	(0.7)%

Table B3-A-3: Facility-Level Impacts of the Final Rule (by NERC Region; 2010)				
Economic Measures	**AEO Base Case**	**Final Rule**	**Difference**	**% Change**
Southeastern Electric Reliability Council (SERC)				
(1) Total Domestic Capacity (MW)	107,458	107,458	0	0.0%
(1a) Closures - Number of Facilities	0	0	0	0.0%
(1b) Closures - Capacity (MW)	0	0	0	0.0%
(2) Generation (GWh)	641,200	641,238	39	0.0%
(3) Revenues (Millions; $2002)	$21,403	$21,410	$7	0.0%
(4) Costs (Millions; $2002)	$12,103	$12,168	$65	0.5%
(4a) Fuel Cost	$6,200	$6,186	($13)	(0.2)%
(4b) Variable O&M	$1,370	$1,375	$5	0.4%
(4c) Fixed O&M	$3,983	$4,057	$73	1.8%
(4d) Capital Cost	$549	$550	$0	0.0%
(5) Pre-Tax Income (Millions; $2002)	$9,300	$9,242	($58)	(0.6)%
(6) Variable Production Costs ($2002/MWh)	$11.81	$11.79	($0.01)	(0.1)%
Southwest Power Pool (SPP)				
(1) Total Domestic Capacity (MW)	20,471	20,471	0	0.0%
(1a) Closures - Number of Facilities	0	0	0	0.0%
(1b) Closures - Capacity (MW)	0	0	0	0.0%
(2) Generation (GWh)	109,277	108,596	(681)	(0.6)%
(3) Revenues (Millions; $2002)	$3,558	$3,537	($21)	(0.6)%
(4) Costs (Millions; $2002)	$1,941	$1,934	($7)	(0.4)%
(4a) Fuel Cost	$1,138	$1,120	($18)	(1.6)%
(4b) Variable O&M	$241	$241	($1)	(0.3)%
(4c) Fixed O&M	$557	$569	$13	2.3%
(4d) Capital Cost	$5	$4	($1)	(20.7)%
(5) Pre-Tax Income (Millions; $2002)	$1,617	$1,603	($14)	(0.9)%
(6) Variable Production Costs ($2002/Mwh)	$12.63	$12.53	($0.10)	(0.8)%
Western Systems Coordinating Council (WSCC)				
(1) Total Domestic Capacity (MW)	29,318	29,309	(8)	0.0%
(1a) Closures - Number of Facilities	0	0	0	0.0%
(1b) Closures - Capacity (MW)	0	0	0	0.0%
(2) Generation (GWh)	143,572	143,242	(331)	(0.2)%
(3) Revenues (Millions; $2002)	$4,902	$4,891	($11)	(0.2)%
(4) Costs (Millions; $2002)	$3,937	$3,961	$24	0.6%
(4a) Fuel Cost	$2,104	$2,096	($9)	(0.4)%
(4b) Variable O&M	$309	$310	$1	0.2%
(4c) Fixed O&M	$1,061	$1,094	$33	3.1%
(4d) Capital Cost	$464	$463	($1)	(0.3)%
(5) Pre-Tax Income (Millions; $2002)	$964	$929	($35)	(3.6)%
(6) Variable Production Costs ($2002/MWh)	$16.81	$16.79	($0.02)	(0.1)%

Source: *IPM analysis: Model runs for Section 316(b) NODA Base Case and the final rule (AEO electricity demand assumptions).*

Table B3-A-4 repeats some of the information presented in Tables B3-5 and B3-A-3 to facilitate a comparison of the results using the two different electricity demand assumptions. The columns labeled "EPA" represent the results based on EPA electricity demand assumptions; the columns labeled"AEO" represent the results based on AEO electricity demand assumptions. The table highlights differences between the two cases of greater than or equal to 0.5 percent with bold font and pale blue shading For a description of the metrics presented in this table, please refer to section B3-3.2.

Table B3-A-4: Comparison of Facility-Level Impacts of the Final Rule (2010)

NERC Region	Baseline Capacity (MW)		Incremental Capacity Closures (MW)		Closures as % of Baseline Capacity		Change in Variable Production Cost per MWh		Change in Generation		Change in Pre-Tax Income	
	EPA	AEO	EPA	AEO	EPA	AEO	EPA	AEO	EPA	AEO	EPA	AEO
ECAR	82,313	82,281	0	0	0.0%	0.0%	0.0%	0.2%	(0.2)%	0.0%	(1.0)%	(1.2)%
ERCOT	43,522	44,413	0	0	0.0%	0.0%	(0.7)%	(1.0)%	**(1.8)%**	**(1.0)%**	**(10.4)%**	**(3.1)%**
FRCC	27,537	27,513	0	0	0.0%	0.0%	**0.3%**	**0.8%**	**(0.8)%**	**0.0%**	(4.0)%	(4.0)%
MAAC	34,376	35,482	0	0	0.0%	0.0%	**0.0%**	**(0.7)%**	**0.2%**	**(0.5)%**	(1.4)%	(1.1)%
MAIN	36,498	38,606	**94**	**493**	**0.3%**	**1.3%**	**0.1%**	**0.6%**	**(0.3)%**	**(1.1)%**	(0.6)%	(0.2)%
MAPP	15,749	15,749	0	0	0.0%	0.0%	(0.1)%	0.0%	0.0%	0.1%	**(0.3)%**	**(0.9)%**
NPCC	37,651	37,219	0	0	0.0%	0.0%	**(1.7)%**	**(0.7)%**	**(3.6)%**	**(1.0)%**	(4.3)%	(4.1)%
SERC	107,450	107,458	0	0	0.0%	0.0%	(0.3)%	(0.1)%	(0.2)%	0.0%	(0.7)%	(0.6)%
SPP	20,471	20,471	0	0	0.0%	0.0%	(0.4)%	(0.8)%	(0.7)%	(0.6)%	(1.0)%	(0.9)%
WSCC	28,431	29,318	58	0	0.2%	0.0%	**(0.9)%**	**(0.1)%**	**(4.3)%**	**(0.2)%**	**(10.4)%**	**(3.6)%**
Total	**433,998**	**438,510**	**152**	**493**	**0.0%**	**0.1%**	**(0.6)%**	**(0.2)%**	**(0.8)%**	**(0.3)%**	**(1.8)%**	**(1.4)%**

Source: *IPM analysis: Model runs for Section 316(b) NODA Base Case and the final rule (EPA and AEO electricity demand assumptions).*

The comparison of the final rule using the two different electricity demand assumptions show the differences listed below. It should be noted that the direction of the differences is not systematic, i.e., in some cases, impacts are greater under the AEO assumptions; in other cases, impacts are greater under the EPA assumptions.

- **Incremental capacity closures** are 341 MW higher under the AEO assumptions than under the EPA assumptions. This corresponds to less than 0.08 percent of Phase II capacity under either base case. The incremental capacity closure results are identical to the market-level results discussed above.

- **Closures as a percentage of baseline capacity** in MAIN are 1.0 percent higher under the AEO assumptions than under the EPA assumptions.

- **The change in variable production cost per MWh** differs by 0.5 percent or more in five NERC regions: in FRCC and MAIN, it increases more under the AEO assumptions than under EPA assumptions; in MAAC, it decreases under AEO assumptions but is unchanged under the EPA assumptions; and in NPPC and WSCC, it decreases less under the AEO assumptions than under the EPA assumptions.

- **The change in generation** differs by 0.5 percent or more in six NERC regions: in ERCOT, FRCC, NPCC, and WSCC, Phase II facilities lose more generation under the EPA assumptions than under the AEO assumptions; in MAIN, they lose more generation under the AEO assumptions than under the EPA assumptions; and in MAAC they experience an increase in generation under the EPA assumptions and a decrease under the AEO assumptions.

- **The change in pre-tax income** differs by 0.5 percent or more in three NERC regions: in MAPP, Phase II facilities experience a slightly higher reduction in pre-tax income under the AEO assumptions than under the EPA assumptions (0.9 percent compared to 0.3 percent). In WSCC and ERCOT, however, the reduction in pre-tax income is substantially higher under the EPA assumptions than under the AEO assumptions (over 10 percent compared to less than 4 percent).

- **For all other measures and regions, the results under the two different electricity demand assumptions are within 0.5 percent of each other.**

b. Individual Phase II facilities

In addition to effects of the final rule on the in-scope Phase II facilities as a group, there may be shifts in economic performance among individual facilities subject to Phase II regulation. To assess such potential shifts, EPA analyzed facility-specific changes in (1) capacity utilization (defined as generation divided by capacity multiplied by the number of hours per year – 8,760); (2) generation; (3) revenues; (4) variable production costs per MWh of generation (defined as variable O&M cost plus fuel cost divided by generation); (5) fuel cost per MWh of generation; and (6) pre-tax income. For each measure, EPA determined the number of Phase II facilities that experience no changes, or an increase or a reduction within three ranges: 1 percent or less, 1 to 3 percent, and more than 3 percent.

Table B3-A-5 (equivalent to Table B3-6) presents the total number of Phase II facilities with different degrees of change in each of these measures. This table excludes 17 facilities with significant status changes including (eight facilities are baseline closures and nine facilities changed their repowering decisions between the base case and policy case). These facilities are either not operating at all in the base case or the post-compliance case, or they experience fundamental changes in the type of units they operate; therefore, the measures presented below would not be meaningful for these facilities. In addition, the changes in production cost per MWh and fuel cost per MWh could not be developed for 58 facilities with zero generation in either the base case or post-compliance scenario. For these facilities, the change in production cost per MWh and fuel cost per MWh is indicated as "n/a."

Table B3-A-5: Number of Individual Phase II Facilities with Operational Changes (2010)

Economic Measures	Reduction			Increase			No Change	N/A
	</= 1%	1-3%	> 3%	</= 1%	1-3%	> 3%		
(1) Change in Capacity Utilization	6	14	17	9	9	7	456	0
(2) Change in Generation	3	5	32	8	6	15	449	0
(3) Change in Revenues	46	26	36	115	14	14	267	0
(4) Change in Variable Production Costs/MWh	38	10	9	136	13	13	241	58
(5) Change in Fuel Costs	47	6	9	35	13	8	342	58
(6) Change in Pre-Tax Income	139	114	195	28	7	9	26	0

[a] For all measures percentages used to assign facilities to impact categories have been rounded to the nearest 10th of a percent.
[b] The change in capacity utilization is the difference between the capacity utilization percentages in the base case and post-compliance case. For all other measures, the change is expressed as the percentage change between the base case and post-compliance values.

Source: IPM analysis: Model runs for Section 316(b) NODA Base Case and the final rule (AEO electricity demand assumptions).

Table B3-A-5 indicates that the majority of Phase II facilities will not experience changes in capacity utilization, generation, or fuel costs per MWh due to compliance with the final rule. Of those facilities with changes in post-compliance capacity utilization and generation, most will experience decreases in these measures. The majority of facilities with changes in post-compliance variable production costs per MWh will experience increases. However, more than 80 percent of those increases will not exceed 1.0 percent. Changes in revenues at most Phase II facilities will also not exceed 1.0 percent. The largest effect of the final rule will be on facilities' pre-tax income: over 85 percent of facilities will experience a reduction in pre-tax income, with about 40 percent experiencing a reduction of 3.0 percent or greater. These reductions are due to a combination of reduced revenues and increased compliance costs.

Chapter B3 - Appendix B

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.

CHAPTER CONTENTS

B3-B.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 regulatory options considered for section 316(b) Phase II regulation. 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 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-B-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 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, CAA 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-B-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-B-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-B-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-B-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.

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Chapter B4: Regulatory Flexibility Analysis

INTRODUCTION

The Regulatory Flexibility Act (RFA) requires EPA to consider the economic impact a new rule will 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 Final Section 316(b) Phase II Existing Facilities Rule on small entities, a small entity is: (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 final Phase II rule.

EPA's analysis showed that the final 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.

B4-1 NUMBER OF IN-SCOPE FACILITIES OWNED BY SMALL ENTITIES

EPA's 2000 Section 316(b) Industry Survey identified 543 generating facilities expected to meet the in-scope requirements of the Final Section 316(b) Phase II Existing Facilities Rule. As described in previous chapters of this document, these 543 facilities represent 554 facilities in the industry.[2] It is impossible, however, to determine the parent entity of extrapolated

[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.

[2] EPA applied sample weights to the 543 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; U.S. EPA 2000).

facilities. The remainder of this parent size analysis therefore discusses research done for the 543 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 543 in-scope facilities, and
- determine the size of the entities owning the 543 facilities.

B4-1.1 Identification of Domestic Parent Entities

Each of the 543 Phase II facilities belongs to one of the following seven types of domestic parent entities: investor-owned, nonutility, federal, state, municipality, political subdivision, or rural electric cooperative. Investor-owned firms and nonutilities are private entities, federal, state, municipal, and political subdivision entities are public entities, and rural electric cooperatives are not-for-profit enterprises. EPA first identified the utility owner of each Phase II facility using the 2001 Form EIA-860 (U.S. DOE, 2001a). In most cases, utilities that are classified as federal, state, municipal, and political subdivision utilities are the domestic parents of the facilities that they own.

For facilities owned by a private entity, including utility (i.e., investor-owned) and nonutility plants, the immediate utility 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). To determine the domestic parent entity for all facilities owned by a private entity, EPA used several publicly available data sources, including data from the Department of Energy’s (DOE) Energy Information Administration, 2001 Form EIA-860; 10-K filings available through the Securities and Exchange Commission’s (SEC) *FreeEdgar* database; corporate websites; and Dun and Bradstreet data (U.S. DOE, 2001a; Edgar Online Inc., 2003; D&B, 2003).

EPA determined that 126 unique entities own the 543 in-scope facilities.

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 investor-owned entities 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 Dun and Bradstreet data, as well as the following publicly available data sources, to obtain the information necessary to determine the entity size: 10-K filings available through the Security and Exchange Commission’s (SEC) *FreeEdgar* database, 2001 EIA Form-860, U.S. Census Data, and company websites (D&B, 2003; EDGAR Online Inc., 2003; U.S. Census Bureau, 2003; U.S. DOE, 2001a). 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 considered large for the purpose of the RFA analysis (U.S. EPA, 1999b).

- ***Municipalities 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 (U.S. Census Bureau, 2003).

- 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 data from the 2001 Form EIA-861 (U.S. DOE, 2001b).

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
5012	Automobiles and Other Motor Vehicles	100 Employees
6512	Operators of Nonresidential Buildings	$5.0 Million
8221	Colleges, Universities, and Professional Schools	$5.0 Million

Source: U.S. SBA, 2000.

Based on these size thresholds, EPA determined that 25 out of the 126 parent entities owning the 543 in-scope facilities are small entities.[3] Sixteen of the 25 small entities are municipalities, six are rural electric cooperatives, one is a nonutility, one is an investor-owned entity, and one is a political subdivision. Table B4-2 presents the distribution of the unique entities by entity type and size. Table B4-2 also presents the distribution of the weighted in-scope facilities by their owner's type and size. No small entity owns more than one in-scope facility; therefore, the 25 small entities own 25 in-scope facilities.

[3] EPA conducted a sensitivity analysis of domestic parent size determinations where entity size for political subdivisions and municipalities is based on utility-level electric output rather than the population threshold of 50,000. The results of this analysis are presented in section B4-A.1 of the appendix to this chapter.

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

Entity Type	Small Entity Size Standard	Number of Entities			Number of Facilities		
		Large	Small	Total	Large	Small	Total
Investor-Owned	SIC Specific	40	1	41	273	1	274
Nonutility	SIC Specific	25	1	26	178	1	179
Federal	Large	1	-	1	14	-	14
State	Large	4	-	4	7	-	7
Municipality	Population of 50,000	20	16	36	32	16	48
Political Subdivision	Population of 50,000	2	1	3	6	1	7
Rural Electric Cooperative	4 million MWh	9	6	15	19	6	25
Total[a]		**101**	**25**	**126**	**529**	**25**	**554**

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

Source: U.S. EPA analysis, 2004.

B4-2 Percent of Small Entities Regulated

In order to assess the small entity impact of the final Phase II rule on the electric generating industry, 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 25 small entities subject to the final Phase II rule. Since only facilities with design intake flows of 50 MGD or more are subject to the final rule, the low number of small entities owning in-scope facilities is not unexpected. EPA identified 1,992 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 final Phase II rule.

Based on Form EIA-861, 3,272 unique utilities operated in the United States in 2001.[4] It was not feasible to conduct the same research for all 3,272 utilities that was done for the 126 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 electric output threshold of 4 million MWh, using the 2001 Form EIA-861 data. However, EPA's analysis of the 126 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, municipalities, and political subdivisions:

- ***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 only one of these five small utilities would also be considered small at the holding company level. EPA therefore estimates that industry-wide only 20 percent of private entities that are small at the utility level would also be small at the holding company level. Accordingly, EPA reduced the industry-wide number of privately-owned small utilities (based on Form EIA-861) by a factor of 80 percent.

- ***Municipalities:*** EPA's research of municipalities owning in-scope facilities showed that 30 municipalities would be small based on the 4 million MWh size standard. Of these 30 entities, 16, or 53 percent, would also be considered

[4] It should be noted that the total number of small entities in the industry used in this analysis is based on regulated entities (utilities) only. Information on the size of unregulated entities (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 final Phase II rule may be overstated.

small when using the population threshold. EPA therefore estimates that industry-wide only 53 percent of municipalities that are small based on electric output would also be small based on population size. Accordingly, EPA reduced the industry-wide number of small municipalities (based on Form EIA-861) by a factor of 47 percent.

- ***Political Subdivisions:*** EPA's research of political subdivisions owning in-scope facilities showed that only one political subdivision owning an in-scope utility is small based on electric output, and that this entity is also small based on population. EPA therefore assumes that all political subdivisions within Form EIA-861 that are small based on electric output are also small based on population. Accordingly, EPA did not make an adjustment to the industry-wide number of small political subdivisions (based on Form EIA-861).

These adjustments are based on the assumption that Phase II utilities (i.e., utilities that own steam electric generators with flow greater than 50 MGD) are representative of the EIA universe of electric utilities (for private entities in terms of their respective sizes at the utility level and the holding company level; for municipalities and political subdivisions in terms of their respective sizes based on electric output and population). If this is not the case, the industry-wide numbers of small entities may be over- or underestimated.

Table B4-3 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 are subject to the final Phase II rule.

Table B4-3: 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 Final Phase II Rule
Private[a, b]	35	2	5.7%
Municipality[b]	983	16	1.6%
Political Subdivision[b]	111	1	0.9%
Rural Electric Cooperatives	862	6	0.7%
All Firm Types	**1,992**	**25**	**1.3%**

a The total number of small private entities includes only investor-owned utilities because information for determining the total number of small nonutilities was unavailable. 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 final Phase II rule may be overstated.

b EPA estimated the total number of small entities for this entity type using the methodology described above.

Source: U.S. DOE, 2001b; D&B, 2003.

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 final 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 final Phase II regulation.

None of the 25 facilities EPA determined to be owned by a small entity has more than one owner. Also, none of the 25 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 final rule.

The estimated annualized post-tax compliance costs include all technology costs, operation and maintenance costs, and permitting costs associated with the final Phase II rule. A detailed summary of how these costs were developed is presented in *Chapter B1: Summary of Compliance Costs*. EPA collected revenue data for the 25 small entities from one of several sources, depending on the availability of information. EPA used revenue data for each entity from one of the following sources, listed in order of preference: (1) Dun and Bradstreet, (2) average utility revenue (1999-2001) from 2001 Form EIA-861, (3) 10-K filings available through the Securities and Exchange Commission's (SEC) *FreeEdgar* database, or (4) other sources such as company websites (D&B, 2003; U.S. DOE, 2001b; Edgar Online Inc., 2003).

The overall annualized compliance costs that facilities owned by small entities are estimated to incur represent between 0.005 and 6.7 percent of the entities' annual sales revenues. Table B4-4 presents the distribution of the entities' cost-to-revenue ratios by small entity type. Of the 25 small entities, only one is estimated to incur compliance costs of greater than three percent of revenues. Eight entities incur compliance costs of between one and three percent of revenues, while the remaining 16 entities incur compliance costs of less than one percent of revenues. Eleven small entities are estimated to incur no costs other than permitting and monitoring costs.

Table B4-4: Impact Ratio Ranges by Small Entity Type

Type of Entity	Impact Ratio Ranges	0-1%	1-3%	>3%	Total
Investor-Owned	0.005%	1	0	0	1
Nonutility	0.01%	1	0	0	1
Municipality	0.28 to 6.72%	8	7	1	16
Political Subdivision	1.01%	0	1	0	1
Rural Electric Cooperative	0.14 to 0.40%	6	0	0	6
Total	**0.005 to 6.72%**	**16**	**8**	**1**	**25**

Source: U.S. EPA analysis, 2004.

EPA has determined that, overall, the impacts faced by small entities as a result of the final Phase II rule are very low. Of the 25 entities owning in-scope facilities, only one entity is expected incur compliance costs of greater than three percent of revenues. Moreover, this entity represents less than one percent of the 126 entities owning in-scope facilities.

B4-4 Summary

EPA estimates that only 25 of 554 in-scope facilities subject to the Final Section 316(b) Phase II Existing Facilities Rule are owned by a small entity. The absolute number of small entities potentially subject to this regulation, 25, 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 25 small entities are low, representing between 0.005 and 6.7 percent of the entities' annual sales revenue. Only one entity is expected to incur compliance costs of greater than three percent of revenues. EPA therefore finds that this final rule would not have a significant economic impact on a substantial number of small entities (no SISNOSE).

The RFA analysis in support of this final Phase II rule is summarized in Table B4-5.

Table B4-5: 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
Investor-Owned[a]	35	1	5.7%	0.005%
Nonutility[a]		1		0.01%
Municipality	983	16	1.6%	0.28 to 6.72%
Political Subdivision	111	1	0.9%	1.01%
Rural Electric Cooperative	862	6	0.7%	0.14 to 0.40%
Total	**1,992**	**25**	**1.3%**	**0.005 to 6.72%**

[a] The total number of small private entities (i.e., investor-owned utilities and nonutilities) includes only investor-owned utilities because information for determining the total number of small nonutilities was unavailable. 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 final Phase II rule may be overstated.

Source: U.S. EPA analysis, 2004.

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Appendix to Chapter B4

Introduction

Chapter Contents

This appendix presents a sensitivity analysis of the domestic parent size determinations for municipalities and political subdivisions, and of the small entity impact assessment that is based on these size determinations. The analysis presented in the body of this chapter used the population-based size threshold (population of less than 50,000) for municipalities and political subdivisions; this appendix compares those results with an analysis that uses the electric output size threshold (total electric output of less than 4 million MWh).

B4-A.1 Regulatory Flexibility Analysis (RFA) Results Using Alternative Domestic Parent Size Criteria

Table B4-A-1 below presents the comparison of the estimated number of large and small entities and of the cost-to-revenue ranges, by entity type, for the two methods of determining municipality and political subdivision entity size.

The top part of the table presents the results, where the small entity determinations are based on EPA guidelines (i.e., municipalities and political subdivisions are evaluation based on population; State and Federal entities are assumed to be large; cooperative entities are evaluated based on electric output; and investor-owned and nonutility entities are evaluated based on SIC-specific criteria). Based on this method, 101 of the 126 unique final parents of Phase II facilities are large and 25 are small. Sixteen of these 25 small entities are municipalities and one is a political subdivision.

The bottom part of the table presents the alternative set of results, where the size determinations for municipalities and political subdivisions are based on electric output at the utility level, using data from 2001 Form EIA-861 (U.S. DOE, 2001). Based on this method, 87 of the 126 unique final parents are large, and 39 are small. Compared to the first method, 14 additional municipalities would be classified as small using the electric output threshold. Ten of these 14 entities have cost-to-revenue ratios of less than 0.5 percent, two have ratios between 0.5 and 1.0 percent, two have ratios between 1.0 and 3.0 percent, and none have ratios of 3.0 percent or greater.

Table B4-A-1: Unique Entities by Type, Size, and Cost-Revenue Range

Entity Type	Large					Small					
	<0.5%	0.5-1%	1-3%	>=3%	Total Large	<0.5%	0.5-1%	1-3%	>=3%	Total Small	Grand Total
Municipality and Political Subdivision Size Based on Population											
Investor-owned	38	2	0	0	40	1	0	0	0	1	41
Nonutility	24	1	0	0	25	1	0	0	0	1	26
Federal	1	0	0	0	1	0	0	0	0	0	1
State	4	0	0	0	4	0	0	0	0	0	4
Municipality	16	2	2	0	20	4	4	7	1	16	36
Political Subdivision	2	0	0	0	2	0	0	1	0	1	3
Cooperative	8	1	0	0	9	6	0	0	0	6	15
Total	**93**	**6**	**2**	**0**	**101**	**12**	**4**	**8**	**1**	**25**	**126**

Table B4-A-1: Unique Entities by Type, Size, and Cost-Revenue Range											
Entity Type	**Large**					**Small**					**Grand Total**
	<0.5%	**0.5-1%**	**1-3%**	**>=3%**	**Total Large**	**<0.5%**	**0.5-1%**	**1-3%**	**>=3%**	**Total Small**	
Municipality and Political Subdivision Size Based on Electric Output											
Investor-owned	38	2	0	0	40	1	0	0	0	1	41
Nonutility	24	1	0	0	25	1	0	0	0	1	26
Federal	1	0	0	0	1	0	0	0	0	0	1
State	4	0	0	0	4	0	0	0	0	0	4
Municipality	6	0	0	0	6	14	6	9	1	30	36
Political Subdivision	2	0	0	0	2	0	0	1	0	1	3
Cooperative	8	1	0	0	9	6	0	0	0	6	15
Total	**83**	**4**	**0**	**0**	**87**	**22**	**6**	**10**	**1**	**39**	**126**

Source: U.S. EPA analysis, 2004.

B4-A-2 below presents a comparison of the minimum and maximum cost-to-revenue ratios, by entity type and size, for the two methods of determining municipality and political subdivision entity size. The overall minimum and maximum cost-to-revenue ratio of unique entities does not vary across the two methods of size determination. However, there are slight differences in both the maximum ratio for large municipalities and the minimum ratio for small municipalities.

Table B4-A-2: Minimum and Maximum Cost-to-Revenue Ratios of Unique Entities by Type and Size				
Utility Type	**Large**		**Small**	
	Minimum	**Maximum**	**Minimum**	**Maximum**
Municipality and Political Subdivision Size Based on Population				
Investor-owned	0.001%	0.640%	0.005%	0.005%
Nonutility	0.006%	0.782%	0.007%	0.007%
Municipality	0.030%	2.442%	0.279%	6.723%
Political Subdivision	0.088%	0.096%	1.009%	1.009%
Cooperative	0.122%	0.579%	0.143%	0.400%
Total	**0.001%**	**2.442%**	**0.005%**	**6.723%**
Municipality and Political Subdivision Size Based on Electric Output				
Investor-owned	0.001%	0.640%	0.005%	0.005%
Nonutility	0.006%	0.782%	0.007%	0.007%
Municipality	0.030%	0.369%	0.046%	6.723%
Political Subdivision	0.088%	0.096%	1.009%	1.009%
Cooperative	0.122%	0.579%	0.143%	0.400%
Total	**0.001%**	**0.782%**	**0.005%**	**6.723%**

Source: U.S. EPA analysis, 2004.

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 the 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 by State, local, and Tribal governments, in the aggregate, or by 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 the 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 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 final Phase II rule would incur annualized post-tax compliance costs of $249.5 million ($2002). Of this total, $216.3 million is incurred by private sector facilities, $23.1 million is incurred by facilities owned by State and local governments, and $10.1 million is incurred by facilities owned by the Federal government.[1] State and Federal permitting authorities incur an additional $4.1 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 $419.1 million in 2009. The highest undiscounted cost incurred by the State and local governments in any one year is approximately $43.5 million in 2008 (including facility compliance costs and State implementation costs). 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, under §202 of the UMRA, EPA has prepared a written statement, presented in the preamble to the final rule, that includes (1) a cost-benefit analysis; (2) an analysis of macroeconomic effects; (3) a summary of State, local, and Tribal input; (4) a discussion related to the least burdensome option requirement; and (5) an analysis of small government burden. This chapter contains additional information to support that statement, including information on compliance and administrative costs, and on impacts on small governments.

B5-1 ANALYSIS OF IMPACTS ON GOVERNMENT ENTITIES

Governments may incur two types of costs as a result of this final rule:

- direct costs to comply with the rule for facilities owned by government entities, and
- administrative costs to implement the rule.

Both types of costs 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 14 of the 554 Phase II facilities.

B5-1.1 Compliance Costs for Government-Owned Facilities

Table B5-1 presents the number of government entities that own facilities subject to the final rule and the number of in-scope facilities owned by those governments. Of the 554 existing in-scope facilities subject to the final rule, 62 are owned by a State or local government. Of those 62 facilities, 48 are owned by municipalities, seven are owned by State governments, and seven are owned by political subdivisions. None of the Phase II facilities are owned by a Tribal government.

Table B5-1 also presents the total annualized compliance costs, average annualized costs, and maximum undiscounted costs in any one year for facilities owned by different types of governments. The total annualized compliance cost incurred by the 62 government-owned Phase II facilities is $23.1 million, or approximately $372,000 per facility.[2] The 48 facilities owned by municipalities incur $17.6 million annually, which is the largest share of the total annualized compliance cost for government-owned facilities. The seven State-owned facilities account for the largest average annualized compliance cost, with approximately $602,000 per facility. The maximum undiscounted cost borne by the 62 facilities is $37.0 million, estimated to be incurred in 2008.

Table B5-1: Compliance Costs of Government-Owned Facilities

Ownership Type	Number of Government Entities	Number of Facilities	Total Annualized Compliance Costs (in millions, $2002)	Average Compliance Cost (per facility, $2002)	Maximum One-Year Facility Compliance Costs (in millions, $2002)
Municipality	36	48	$17.6	$366,000	$24.5 (2005)
State Government	4	7	$4.2	$602,000	$13.9 (2008)
Political Subdivision	3	7	$1.3	$180,000	$1.8 (2006)
Total	**43**	**62**	**$23.1**	**$372,000**	**$37.0 (2008)**

Source: U.S. EPA analysis, 2004.

B5-1.2 Administrative Costs

The requirements of section 316(b) are implemented through the National Pollutant Discharge Elimination System (NPDES) permit program. Forty-five 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 final 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 $4.0 million, annualized over 30 years at a seven percent discount rate. Table B5-2 below presents the estimated 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 calculate annualized costs.

[3] The costs associated with implementing the requirement of the final Phase II rule are documented in EPA's Information Collection Request (U.S. EPA, 2003).

Table B5-2: Annualized Government Administrative Costs (in millions, $2002)	
Activity	**Cost**
Start-Up Activities	$0.02
Permitting Activities	$2.94
Annual Activities	$1.04
Total	**$4.00**

Source: U.S. EPA analysis, 2004.

Start-up costs are incurred only once by each of the 46 permitting authorities. Permitting costs and annual activities are incurred for every permit. Based on the specific permitting requirements of each in-scope facility, EPA calculated total government costs of implementing the final Phase II rule by adding the cost of start-up activities to the aggregate costs for each facility's first post-promulgation permit, repermitting activities, and annual activities. The maximum one-year undiscounted implementation cost incurred by the government is $6.5 million, in 2008. EPA notes that the annualized cost of administrative activities depends on when they are incurred. If facilities come into compliance later than assumed in this analysis, permitting authorities' administrative activities will also occur in later years. As a result, the annualized costs of the rule to permitting authorities will be lower because administrative costs incurred in later years have lower net present values.

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 final 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 final rule than are currently required.

The following subsections present more detail on the three types of implementation costs.

a. Start-up activities

Forty-five States and one Territory with NPDES permitting authority are expected to undertake start-up activities to prepare for administering the final Phase II 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 final Phase II rule requirements for each facility's NPDES permit. In addition, permitting authorities are expected to incur other direct costs, e.g., for purchasing supplies and copying. Table B5-3 shows the total start-up costs EPA estimated permitting authorities to incur. Each permitting authority is estimated to incur start-up costs of $3,986 as a result of the final Phase II rule. EPA assumes that the initial start-up activities will be incurred by all permitting authorities at the end of 2004, the year of promulgation of the final Phase II rule.

Table B5-3: Government Costs of Start-Up Activities (per Regulatory Authority;$2002)	
Start-Up Activity	**Start-Up Costs**
Read and Understand Rule	$994
Mobilization/Planning	$1,738
Training	$1,205
Other Direct Costs	$50
Total	**$3,986**

Source: U.S. EPA analysis, 2004.

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. For this analysis, EPA assumed that the first permit containing the new section 316(b) requirements will be issued between 2005 and 2009.[4] Repermitting activities will take place every five years after initial permitting.

The final 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 required by the initial post-promulgation and each subsequent permit are similar. 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 (however, the costs associated with permitting facilities with (a) a recirculating system or a wedgewire screen in the baseline or (b) a facility installing a new wedgewire screen are less). The burden of repermitting is expected to be smaller than the burden of initial permitting 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 a site-specific determination if it can demonstrate that the proposed technology will result in environmental performance within a watershed that is comparable to the reductions in impingement and entrainment mortality that would otherwise be achieved under the final Phase II rule. EPA estimates that 211 facilities will apply for a site-specific determination.[5]

[4] For an explanation of how the compliance years were assigned to facilities subject to the final Phase II rule, see *Chapter B1: Summary of Compliance Costs* of this EBA.

[5] EPA is not including this site-specific determination as a direct cost for complying facilities because this is an optional activity that the facility will choose only in cases where the cost of the alternative technology plus the cost of the site-specific determination is less than the cost of the technology otherwise required by the final Phase II rule. However, the site-specific determination costs for permitting authorities are not optional, and thus are included in EPA's estimates of total cost.

Table B5-4: Government Permitting Costs (per Permit; $2002)		
Activity	**First Permit**	**Repermitting**
Review Source Water Physical Data	$290	$114
Review CWIS Data	$871	$259
Review CWS Operation Narrative	$871	$259
Review Proposal for Collection of Information for Comprehensive Demonstration Study	$1,325	$414
Review Source Water Body Flow Information	$290	$114
Review Design and Construction Technology Plan	$1,488	$424
Review Impingement Mortality & Entrainment Characterization Study	$22,200	$6,660
Review Pilot Study for New Impingement & Entrainment Technology	$1,325	$414
Review Restoration Measures[a]	$23,760	$7,128
Determine Monitoring Frequency	$290	$114
Determine Record Keeping and Reporting Frequency	$290	$114
Considering Public Comments	$1,325	$414
Issuing Permits	$263	$62
Permit Record Keeping	$131	$24
Other Direct Costs	$300	$300
Total (without site-specific determination of BTA)[b]	**$33,636**	**$10,399**
Review Information to Support Site-Specific Determination of BTA[c]	$47,520	$14,256
Establish Requirements for Site-Specific Technology[c]	$1,162	$322
Total Cost of Site-Specific Activities	**$48,682**	**$14,578**
Total (including a site-specific determination of BTA)[b]	**$82,317**	**$24,977**

a Assumed to apply to only 10 percent of facilities.
b Individual numbers may not add up to total due to independent rounding.
c Cost incurred only for permits of facilities conducting site-specific demonstrations.

Source: U.S. EPA analysis, 2004.

Table B5-4 shows that initial post-promulgation permits that do not require a site-specific determination of BTA are expected to impose an average per permit cost of $33,636 on the issuing permitting authority. For initial post-promulgation permits that include a site-specific determination, the State administrative costs associated with the site-specific determination add an additional $48,682, resulting in total per permit costs of $82,317.

The State administrative cost for a permit renewal that does not include a site-specific determination is $10,399. For facilities that do conduct a site-specific determination, the cost per permit imposed on the permitting authority increases by $14,578, resulting in an average permit cost of $24,977.

Another start-up cost incurred by permitting authorities is associated with review of verification studies conducted at facilities. In addition to reviewing the studies, permitting authorities must modify permits in case of unfavorable study results. In total, verification study review is expected to cost permitting authorities $780 per permit. Table B5-5 lists the components of verification study review.

Table B5-5: Government Costs of Verification Study Review (per Permit; $2002)	
Activity	**Costs**
Review of Verification Studies	$228
Permit Modification Due to Unfavorable Results	$518
Recordkeeping	$24
Other Direct Costs	$10
Total	**$780**

Source: U.S. EPA analysis, 2004.

A final component of start-up costs is the cost associated with alternative regulatory requirements. States can adopt alternative regulatory requirements in their NPDES program that result in reductions of impingement mortality and entrainment within a watershed. If these States can demonstrate to the Administrator that the reductions are comparable to what would otherwise be achieved under rule, the Administrator will approve these alternative regulatory requirements. EPA estimates that 10 regulatory permitting authorities will incur costs associated with alternative regulatory requirements. The expected per permit cost to permitting authorities of establishing alternative regulatory requirements at those facilities is $7,054. Table B5-6 shows the cost of each component of establishing alternative regulatory requirements.

Table B5-6: Government Costs of Alternative Regulatory Requirements (per Permit; $2002)	
Activity	**Costs**
Document Alternative Regulatory Requirements	$1,368
Document Environmental Conditions within Watershed	$1,824
Include Supporting Historical Studies, Calculations, and Analyses	$3,528
Submit Documentation	$96
Recordkeeping	$138
Other Direct Costs	$100
Total	**$7,054**

Source: U.S. EPA analysis, 2004.

c. Annual activities

In addition to the start-up and permitting activities discussed previously, permitting authorities will have to carry out certain annual activities to ensure the continued implementation of the requirements of the final Phase II rule. These annual activities include reviewing yearly status reports, tracking compliance, determination on monitoring frequency reduction, and record keeping.

Table B5-7 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 $1,884 is estimated for each permit per year.

Table B5-7: Government Costs for Annual Activities (per Permit; $2002)	
Annual Activity	**Annual Costs**
Review of Yearly Status Report	$684
Compliance Tracking	$581
Determination of Monitoring Frequency Reduction	$456
Record Keeping	$138
Other Direct Costs	$25
Total	**$1,884**

Source: U.S. EPA analysis, 2004.

B5-1.3 Impacts on Small Governments

EPA's analysis also considered whether the final rule may significantly or uniquely affect small governments (i.e., governments with a population of less than 50,000). Table B5-8 presents by ownership size: (1) the number of entities owning facilities subject to the regulation; (2) the number of facilities; (3) the estimated annualized post-tax compliance costs; and (4) the average annualized post-tax compliance cost per facility. EPA identified 17 facilities (of the 62 government-owned facilities) subject to the final rule that are owned by small governments.[6]

Table B5-8: Number of Regulated Facilities and Post-Tax Compliance Costs by Entity Size

Ownership Size	Number of Entities	Number of Phase II Facilities	Total Annualized Compliance Costs (post-tax, in millions, $2002)	Average Annualized Compliance Cost per Facility (post-tax, $2002)	Maximum Annualized Per Facility Compliance Costs (post-tax, in millions, $2002)
Facilities Owned by Small Governments	17	17	$5.4	$316,300	$1.3
Facilities Owned by Large Governments	27	59	$27.8	$470,200	$2.3
Facilities Owned by Small Non-Governments	8	8	$1.4	$173,800	$0.3
Facilities Owned by Large Non-Governments	74	470	$214.9	$457,600	$10.8
All Facilities	**126**	**554**	**$249.5**	**$450,500**	**$10.8**

Source: U.S. EPA analysis, 2004.

The total annualized compliance cost for the 17 facilities owned by small governments is $5.4 million, or approximately $316,300 per facility. In comparison, the total annualized compliance cost for the 59 facilities owned by large governments is $27.8 million, or approximately $470,200 per facility. The eight small non-government facilities incur total annualized compliance cost of $1.4 million, or $173,800 per facility. Total annualized compliance cost for the 470 large non-government facilities is $214.9 million, or $457,600 per facility. These numbers support EPA's evaluation that small governments would not be significantly or uniquely affected by the final Phase II rule. The per facility average compliance

[6] *Chapter B4: Regulatory Flexibility Analysis* of this EBA provides more information on EPA's determination of the size of entities owning the 554 in-scope facilities.

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 final Phase II rule.

B5-2 Compliance Costs for the Private Sector

The private sector only incurs compliance costs associated with facilities subject to this final rule. These direct facility costs already include the cost to facilities of obtaining their NPDES permits. Of the 554 in-scope facilities subject to the final rule, EPA identified 478 to be owned by a private entity.[7]

The methodology for determining compliance costs for the Phase II facilities is presented in *Chapter B1: Summary of Compliance Costs* of this EBA. Total annualized (post-tax) compliance costs for the 478 privately-owned facilities are estimated to be $216 million, discounted at seven percent. The maximum aggregate post-tax cost (undiscounted) for all 478 facilities in any one year is estimated to be $419 million, which will be incurred in 2009.

B5-3 Summary of UMRA Analysis

EPA estimates that the final 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 B5-9 summarizes the costs to comply with the rule for the 540 in-scope facilities (excluding the 14 facilities owned by the Federal government) and the costs to implement the rule for permitting authorities.

Table B5-9: Summary of UMRA Costs (in millions, $2002)

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	$23.1	$4.0	$27.1	$37.0	$6.5	$43.5
Private Sector	$216.3	n/a	$216.3	$419.1	n/a	$419.1

Source: U.S. EPA analysis, 2004.

The total annualized cost of the final section 316(b) Phase II Existing Facilities Rule to State and local governments is approximately $27.1 million, consisting of $23.1 million in facility compliance costs and $4.0 million in government implementation costs. The maximum one-year costs that will be incurred by government entities is expected to be $43.5 million ($37.0 million in facility compliance costs and $6.5 million in implementation costs), incurred in 2008. Total annualized costs borne by the private sector is estimated by EPA to be $216.3 million. The maximum one-year cost to the private sector is $419.1 million, which will be incurred in 2009.

[7] For the purposes of this analysis, private entities include utilities, nonutilities, and rural electric cooperatives.

REFERENCES

U.S. Environmental Protection Agency (U.S. EPA). 2004. *Information Collection Request for Cooling Water Intake Structures, Phase II Existing Facility Final Rule.* ICR Number 2060.02. February 2004.

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Chapter B6: Other Administrative Requirements

INTRODUCTION

This chapter presents several other analyses in support of the Final Section 316(b) 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 final 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 requires 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 will 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 will 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, will benefit from improved environmental conditions as a result of this rule. Under current conditions, EPA estimates that over 1.5 billion fish (expressed as age 1 equivalents) of recreational and commercial species are lost annually due to impingement and entrainment at in-scope Phase II facilities. Under the final rule, more than 0.5 billion individuals of these commercially and recreationally sought fish species (age 1 equivalents) are estimated to survive and join the fishery each year. These additional 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 five 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 five 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 14,000 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 people 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

Region	Number of In-Scope Facilities	Average 2000 Population (millions)[a]	Average Estimated Subsistence Fishing Population[b]
California	20	6.5	28,000
North Atlantic	22	5.1	13,000
Mid Atlantic	44	10.3	8,000
South Atlantic	16	1.5	18,000
Gulf of Mexico	24	1.9	14,000
Great Lakes	56	2.8	11,000
Hawaii	3	1.8	17,000
Interior U.S.	358	1.5	11,000
All In-Scope Facilities (Unweighted)	**543**	**2.7**	**14,000**

[a] Total population living withing 50 miles.
[b] Estimated as 10% of total estimated anglers living within 50 miles of an in-scope facility. Rounded to nearest thousand.

Source: Angler estimates calculated from U.S. DOI, 1997; U.S. EPA analysis, 2004.

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 543 in-scope facilities for which survey data are available.

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 tend to have significant Asian populations. As such, individuals in these areas who rely on subsistence fishing may benefit greatly from 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 (23 of 543, or 4.2%), non-white populations (105 of 543, or 19.3%), Native American populations (33 of 543 or 6.1%), or Asian populations (42 of 543 or 7.7%), that are significantly higher than national levels.

Based on these results, EPA does not believe that this rule will have an exclusionary effect, deny persons the benefits of the National Pollution Discharge Elimination System (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.

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
North Atlantic	22	9.3%	14.8%	0.7%	3.6%	-	1	-	2
Mid Atlantic	44	11.6%	34.1%	0.8%	6.1%	-	32	-	22
South Atlantic	16	13.2%	25.5%	0.7%	2.0%	-	3	-	-
Gulf of Mexico	24	14.4%	24.1%	0.9%	2.5%	2	6	-	-
California	20	13.4%	33.6%	1.9%	12.6%	-	12	1	15
Great Lakes	56	11.2%	18.7%	1.2%	2.2%	-	4	5	-
Hawaii	3	9.7%	64.8%	1.8%	61.6%	-	3	-	3
Interior U.S.	358	12.8%	17.4%	1.7%	1.7%	21	44	27	-
All In-Scope Facilities (Unweighted)	**543**	**12.5%**	**20.1%**	**1.5%**	**3.0%**	**23**	**105**	**33**	**42**
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: Average poverty rate compiled from U.S. DOC, 1998; population estimates compiled from U.S. DOC, 2000.

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 final 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 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 regulation.

This final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. EPA expects an annual burden of 104,606 hours with total average annual cost of $4.8 million for States to collectively administer this rule during the first three years after promulgation. EPA has identified 62 Phase II existing facilities that are owned by State or local government entities. The estimated average annual compliance cost incurred by these facilities is $372,000 per facility.

The final national cooling water intake structure requirements will 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 final Phase II regulation to have substantial direct effects on either authorized or nonauthorized States or on local governments because it will not change how EPA and the States and local governments interact or their respective authority or responsibilities for implementing the NPDES program. This 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 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 rule alters 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 final 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 the Phase II rulemaking effort. 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 further organized a meeting of technical experts (May 23, 2001) and a Symposium on Technologies for Protecting Aquatic Organisms from Cooling Water Intake Structures (BTA symposium, May 6-7, 2003).

- 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 130 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. In addition, EPA received more than 170 comments on the Phase II proposed rule and NODA, including comments from State and local government representatives from Arkansas, Alabama, Indiana, Tennessee, and Rhode Island.

- 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 the proposed Phase II 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 final Phase II Existing Facilities Rule will advance the objective of Executive Order 13158.

Marine protected areas (MPAs) 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 are developing an inventory of MPAs in the U.S. that are protected and managed under Federal, State, Territorial, Tribal, or local laws. This list has not been completed, but it currently includes 32 Federal sites in the New England region, 31 in the Middle Atlantic region, 43 in the South Atlantic region, 45 in the Gulf of Mexico region, 12 in the Caribbean region, 15 in the Great Lakes region, and 46 in the U.S. West Coast region. Examples of marine protected areas 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 final 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 final 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 final rule is owned by tribal governments. This final 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, ("Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use" (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 rule is not 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 final rule does not contain any compliance requirements that will:

- reduce crude oil supply in excess of 10,000 barrels per day;
- reduce fuel production in excess of 4,000 barrels per day;
- reduce coal production in excess of 5 million tons per day;
- reduce electricity production in excess of 1 billion kilowatt hours per day or in excess of 500 megawatts of installed capacity;
- increase energy prices in excess of 10 percent;
- increase the cost of energy distribution in excess of 10 percent;
- significantly increase dependence on foreign supplies of energy; or
- have other similar adverse outcomes, particularly unintended ones.

Of the potential significant adverse effects on the supply, distribution, or use of energy (listed above) only a few apply to the final Phase II rule. Through increases in the cost of generating electricity and shifts in the types of generators employed, the final Phase II rule might affect (1) the production of coal, (2) the production of electricity, (3) the amount of installed capacity, (4) energy prices, and (5) the dependence on foreign supplies of energy. EPA used the results from its electricity market model analysis (see Chapter B3) to analyze the final rule for each of these potential effects.

❖ *Production of coal*

EPA estimates that this final rule will decrease the annual use of coal for electricity generation by 82.3 trillion Btu (TBtu), or 0.4 percent. This reduction converts to 4.07 million tons of coal per year or 11,150 tons of coal per day.[1] Assuming that a reduction in the use of coal for electricity generation results in a similar reduction in coal production, EPA concludes that this rule will not have a significant impact on the national production of coal as defined by the thresholds listed above.

❖ *Production of electricity*

EPA's electricity market analysis did not allow for an explicit consideration of the changes in the production of electricity. However, based on the small effects on installed capacity and electricity prices, EPA concludes that this final rule will not reduce electricity production in excess of 1 billion kilowatt hours per day.

❖ *Installed capacity*

The final rule does not contain requirements that will permanently reduce installed capacity, for example through parasitic losses or auxiliary power requirements. However, the rule does contain requirements that may lead to one-time temporary downtimes of steam electric generators subject to this rule, ranging from two to eleven weeks. EPA estimates that approximately 100 facilities, accounting for 70,000 megawatts (MW) of generating capacity, will experience such downtimes. However, EPA's analyses indicate that these downtimes will not have a significant adverse effect on the supply, distribution, or use of energy (see Chapter B3 of the Final EBA). In addition, EPA estimates that this rule will lead to only 152 MW in incremental permanent capacity closures, well below the 500 MW impact threshold.

❖ *Energy prices*

The final rule will not significantly affect energy prices in either the long run or the short run. EPA estimates that, in the long run, energy prices will rise by less than one percent in all but two North American Electric Reliability Council (NERC) regions. The Electric Reliability Council of Texas (ERCOT) is estimated to have the largest increase in electricity prices with 5.8 percent in 2010 and 1.3 percent in 2013. The Florida Reliability Coordinating Council (FRCC) is estimated to experience electricity price increases of 1.3 percent in 2013 and 1.6 percent in 2020. In the short run (2008), energy prices are estimated to rise between 0.4 and 3.0 percent in all regions. EPA estimates that five regions will experience increases of less than 0.7 percent while five regions will experience increases between 1.1 and 3.0 percent. No region will experience energy price increases of more than 10 percent as a result of the final Phase II rule.

❖ *Dependence on foreign supplies of energy*

EPA's electricity market analysis did not allow for an explicit consideration of the effects of this final rule on foreign imports of energy. However, this rule only affects electricity generators, which are generally not subject to significant foreign competition. (Only Canada and Mexico are connected to the U.S. electricity grid, and transmission losses are substantial when electricity is transmitted over long distances.) In addition, the effects on installed capacity and electricity prices, are

[1] This conversion assumes an average energy content of 10,115 Btu per pound of coal (U.S. DOE, 2000).

estimated to be small. EPA therefore concludes that this final rule will not significantly increase dependence on foreign supplies of energy.

Based on these analyses, EPA concludes that this final rule will have minimal energy effects at a national and regional level. As a result, EPA did not prepare a Statement of Energy Effects. For more detail on effects of this final rule on energy markets, see *Chapter C3: Electricity Market Model Analysis*.

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 final Phase II regulation are documented in the Information Collection Request (ICR) which accompanies this regulation (U.S. EPA, 2004).

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 final rule does not involve such technical standards. Therefore, EPA is not considering the use of any voluntary consensus standards.

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Chapter C1: Regional Approach

Introduction

Chapter Contents

For the Section 316(b) Phase II benefits analysis EPA examined impingement and entrainment (I&E) losses, and the economic benefits of reducing these losses, at the regional level. The estimated benefits were then aggregated across all regions to yield a national benefit estimate.

The primary objective of the regional approach was to refine the scale of resolution of the benefits case studies conducted for proposal, so that extrapolations were within regions rather than nation-wide. Extrapolation of I&E rates was necessary because not all in scope facilities have I&E data. It also was not possible to evaluate all of the data from the many facilities nation-wide that have conducted I&E studies. At the same time, in many cases available data were not suitable for further analysis.

While EPA believes that extrapolation within regions was reasonable for the national rulemaking, the Agency is not advocating that this approach be followed for impact and/or benefits analyses that might be conducted for individual National Pollution Discharge Elimination System (NPDES) permits. At the individual permit level it is possible to conduct a more detailed, site-specific analysis on the environmental ramifications of cooling water intake structures than was necessary or feasible for the national-level analysis.

C1-1 Definitions of Regions

EPA defined seven regions for its analysis based on similarities in the affected aquatic species and characteristics of commercial and recreational fishing activities in the area. These regions and the waterbody types within each region are described below. Maps showing the facilities in each region that are in scope of the Phase II rule are provided at the end of this chapter.

C1-1.1 Coastal Regions

Coastal regions are fisheries regions defined by the National Atmospheric and Oceanic Administration (NOAA) National Marine Fisheries Service (NMFS). Table C1-1 presents these geographic areas and the number of facilities included in each NMFS region. The California region includes all estuary/tidal river and ocean facilities in California. The North Atlantic region includes all estuary/tidal river and ocean facilities in Maine, New Hampshire, Massachusetts, Connecticut, and Rhode Island. The Mid Atlantic region includes all estuary/tidal river and ocean facilities in New York, New Jersey, Pennsylvania, Maryland, the District of Columbia, Delaware, and Virginia. The South Atlantic region includes all estuary/tidal river and ocean facilities in North Carolina, South Carolina, Georgia, and the east coast of Florida. The Gulf of Mexico region includes all estuary/tidal river and ocean facilities in Texas, Louisiana, Mississippi, and Alabama and the west coast of Florida. There are no facilities in scope of Phase II regulation in Oregon or Washington State.

Table C1-1: Definition of Costal Regions				
Region	**Geographic Area**	**Number of Estuarine Facilities**	**Number of Ocean Facilities**	**Total Number of Facilities**
California	California	8	12	20
North Atlantic	Maine, New Hampshire, Massachusetts, Rhode Island, Connecticut	20	2	22
Mid Atlantic	New York, New Jersey, Delaware, Maryland and Virginia	44	0	44
South Atlantic	North Carolina, South Carolina, Georgia, East Florida	15	1	16
Gulf of Mexico	West Florida, Alabama, Missouri, Louisiana, Texas	21	3	24
Total Number of Estuarine and Ocean Facilities[a]		**108**	**18**	**126**

[a] In addition, there are 3 ocean facilities in Hawaii that are not included in the NMFS-defined regions.

Source: U.S. EPA analysis, 2004.

C1-1.2 Great Lakes Region

The Great Lakes region includes all 56 facilities located on the shoreline of a Great Lake or on a waterway with open passage to a Great Lake and within 30 miles of a lake in Minnesota, Wisconsin, Illinois, Michigan, Indiana, Ohio, Pennsylvania, and New York. This definition is based on EPA's estimate of the extent of the spawning habitat of Great Lakes fish species, including spawning habitat in rivers and tributaries of the Great Lakes. The distance each species may travel upstream to spawn varies depending on both the species and the waterway, and is influenced by obstacles such as dams. However, after consultation with local fisheries experts, EPA determined that inclusion of waters within 30 miles of the Great Lakes is likely to encompass spawning areas of Great Lakes fishes. EPA used geographic information systems (GIS) to determine which facilities are on a waterbody that has unobstructed passage to the Great Lakes and is within 30 miles of a Great Lake. Data from the Lake Huron Project were used for areas encompassed by that project. For areas not covered by the Lake Huron Project, this was done using the Enhanced Reach File 1 (ERF1) streams coverage (Alexander et al., 1999), the national dams coverage (U.S. Army Corps of Engineers, 1999), and a basic US states coverage. No facilities drawing from other lakes or reservoirs were included among the Great Lake facilities unless the waterbodies were connected to the Great Lakes.

C1-1.3 Inland Region

The Inland region includes all 358 facilities located on freshwater rivers or streams and lakes or reservoirs, in all States, with the exception of facilities located in the Great Lakes region (defined above in Section C1-1.2). Of the 358 inland facilities, 244 are located on freshwater rivers or streams and 114 are located on lakes or reservoirs.

C1-2 Development of Regional I&E Estimates

For the case studies presented at proposal, EPA conducted species-specific analyses of I&E on a facility-specific basis. For the regional studies, EPA evaluated species groups comprised of species with similar life histories. Groups were based on biological family groups or the groupings used by NMFS for landings data. For example, various anchovy species were grouped together as "anchovies." For the regional studies, EPA evaluated I&E rates for such species groups and developed a regional total I&E estimate by summing results for each group. An exception was made for species of exceptionally high commercial or recreational value (e.g., striped bass). Such species were evaluated as single species.

Aggregation of species into groups of similar species facilitated parameterization of the fisheries models used by EPA to evaluate facility I&E monitoring data. Life history data are very limited for many of the species that are impinged and entrained. As a result, there are many data gaps for individual species. To overcome this limitation, EPA used the available life history data for closely related species to construct a single representative life history for a given species group. For previously completed case studies, EPA used the species-specific life history information that was previously developed and then aggregated I&E results for the species within a given group to obtain a group estimate. Appendices to the regional studies (Parts B-H of the Regional Study Document; U.S. EPA, 2004) provide tables of all life history data and data sources used by EPA for the regional analyses.

EPA believes that the species group approach is appropriate for the national rulemaking given the many data limitations associated with the lack of knowledge of specific fish life histories, particularly the growth and mortality rates of early life stages. However, EPA is not endorsing this approach for analyses to support individual permits related to specific waterbodies and facilities. At the individual permit level, more detailed information regarding the life histories of individual species is often available and, when available, it should be used.

EPA converted annual I&E losses for each species group into (1) age 1 equivalents, (2) fishery yield, and (3) biomass production foregone using standard fishery modeling techniques (Ricker, 1975; Hilborn and Walters, 1992; Quinn and Deriso, 1999). Details of these methods are provided in Chapter A5 of the Regional Study Document. Chapter A6 discusses data uncertainties. For all analyses, EPA assumed 100 percent entrainment mortality based on the analysis of entrainment survival studies presented in Chapter A7 of Part A of the Regional Study Document.

To obtain regional I&E estimates, EPA extrapolated losses from facilities with I&E data to facilities without data. These results were then summed to obtain a regional total. Average annual results for facilities with I&E data were averaged and extrapolated on the basis of operational flow, in millions of gallons per day (MGD), to facilities without data. The extrapolation method used, by region, is:

Total losses at case study facilities * Total flow in the region / Flow at case study facilities

These regional estimates are for 540 in-scope facilities that completed the 316(b) facility survey (excluding the three Hawaii facilities). To obtain complete national I&E estimates EPA performed two additional steps. First, a set of statistical survey weights was developed to estimate losses for 11 facilities that did not provide a completed 316(b) survey. Applying these weights provides and estimate for all 551 in-scope facilities in the continental U.S. Second, EPA estimated losses at the three in-scope facilities in Hawaii based on losses per unit flow in the other coastal regions. The weighting and the estimates of losses in Hawaii provide loss estimates for all 554 in-scope facilities.

The regional analyses incorporated data for many more facilities than were evaluated for proposal, and thus improved the basis for EPA's national benefits estimates.

C1-3 DEVELOPMENT OF REGIONAL AND NATIONAL BENEFITS ESTIMATES

EPA considered the following benefit categories in its regional and national benefits analyses: recreational fishing benefits, commercial fishing benefits, and non-use benefits. Non-use benefits include benefits from reduced I&E of forage species, threatened and endangered species, and the non-landed portion of commercial and recreational species. The analysis of direct use benefits for each region includes benefits to recreational anglers from improved fishing opportunities due to reduced impingement and entrainment based on a region-specific valuation function and benefits from improved commercial fishery yield. Details of the methods used to estimate commercial fishery benefits and recreational fishery benefits are provided in Chapters A10 and A11of the section 316(b) Phase II Regional Study Document (U.S. EPA, 2004), respectively. EPA also explored methods for evaluating non-use benefits, although the Agency was not able to monetize nonuse values (for further detail see Chapter A12 of the Regional Study Document).

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Chapter C2: Summary of Current Losses Due to I&E

Introduction

This chapter summarizes the results of the seven regional analyses and presents the total monetary values of national baseline losses for all 554 facilities subject to the Final Section 316(b) Phase II Existing Facilities Rule. For a discussion of the monetary values of the national economic benefits expected from reducing impingement and entrainment (I&E) losses, refer to Chapter C3 of this document.

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Greater detail on the methods and data used in the regional analyses are provided in Chapter C1 of this EBA and in the Regional Study Document (U.S. EPA, 2004): the methods used to estimate I&E are described in Chapter A5; the methods used to estimate the value of the benefits of prevented I&E losses are described in Chapters A9 through A15; the results of the regional analyses are presented in Parts B through H; and a summary of national benefits is provided in Part I.

C2-1 Summary of I&E Losses

Using standard fishery modeling techniques, EPA constructed models that combined facility-derived impingement and entrainment counts with relevant life history data to derive estimates of:

(1) age 1 equivalent losses (the number of individual organisms of different ages impinged and entrained by facility intakes, expressed as age 1 equivalents[1]),
(2) foregone fishery yield (pounds of commercial harvest and numbers of recreational fish and shellfish that are not harvested due to impingement and entrainment, including indirect losses of harvested species due to losses of forage species), and
(3) foregone biomass production (the expected total amount of future growth of impinged and entrained organisms, expressed as pounds, had they not been impinged or entrained).

Note that estimates of foregone fishery yield include the yield of harvested species that is lost due to losses of forage species as well as direct losses of harvested species. The conversion of forage to yield contributes only a very small fraction to the total foregone yield. Details of the methods used for these analyses are provided in Chapter A5 of the Regional Study Document. For all analyses, EPA assumed 100 percent entrainment mortality based on the analysis of entrainment survival studies presented in Chapter A7 of the Regional Study Document.

Table C2-1 presents EPA's estimates of the current I&E losses in each region. The table shows that total national losses of age 1 equivalents for all 554 facilities equals 3.4 billion fish. Nationwide, EPA estimates that 165.0 million pounds of fishery yield is foregone under current rates of I&E, and 717.1 million pounds of potential future biomass production is lost. The

[1] Age 1 equivalent losses are calculated using the the Equivalent Adult Model (EAM), a method for expressing I&E losses as an equivalent number of individuals at some other life stage. The method provides a convenient means of converting losses of fish eggs and larvae into units of individual fish and provides a standard metric for comparing losses among species, years, and regions. For the section 316(b) regional case studies, EPA expressed I&E losses at all life stages as an equivalent number of age 1 individuals. For a more detailed explanation, see Chapter A5 of the Regional Studies document.

table shows about half of all age 1 equivalent losses, or 1.7 billion fish, occur in the Mid-Atlantic region. The Mid-Atlantic region also has the highest foregone fishery yield, followed by the Gulf of Mexico region and the California region. The largest amount of foregone future biomass production, 289.1 million pounds, is attributable to I&E in the North Atlantic region. More detailed discussion of the losses in each region are provided in Sections B through H of the Regional Study Document.

Table C2-1: Total Current Annual Impingement and Entrainment, By Region[a]

Region[a]	Age 1 Equivalents (millions)	Foregone Fishery Yield (million lbs)	Biomass Production Foregone (million lbs)
California	312.9	28.9	43.6
North Atlantic	65.7	1.3	289.1
Mid-Atlantic	1,733.1	67.2	110.9
South Atlantic[b]	342.5	18.3	28.3
Gulf of Mexico	191.2	35.8	48.1
Great Lakes	319.1	3.6	19.3
Inland	369.0	3.5	122.0
Total (weighted)	**3,449.4**	**165.0**	**717.1**

[a] Regional results are unweighted. National totals are sample-weighted and include Hawaii.
[b] EPA estimated losses in the South Atlantic by extrapolating results from the Mid-Atlantic and Gulf regions.

Source: U.S. EPA analysis, 2004.

C2-2 Summary of Losses: Economic Value

In total, EPA found 554 facilities to be in scope of the final section 316(b) Phase II rule. However, the regional estimates of baseline losses reflect only the 540 in-scope facilities that completed 316(b) questionnaires (excluding three facilities in Hawaii). In order to calculate national losses for all 554 facilities, including the three facilities located in Hawaii and the eleven other facilities that did not complete the questionnaire, EPA extrapolated losses from other facilities and regions, based on intake flows and a set of statistical weights. See Chapter I1 of the Regional Studies document for a more detailed discussion of the extrapolation procedure.

As mentioned in Chapter A12, EPA estimated non-use benefits only qualitatively. As a result, the Agency was not able to directly monetize the value of losses for 98.2% of the age-one equivalent losses of all commercial, recreational, and forage species for the 316(b) Phase II regulation. This means that the estimates of baseline losses presented in this section represent the losses associated with less than 2% of the total age-one equivalents lost due to impingement and entrainment by cooling water intake structures (CWISs) and should be interpreted with caution. See Chapter A9 of the Regional Case Study document for a detailed description of the ecological benefits from reduced I&E.

Table C2-2 presents EPA's estimates of the value of annual baseline I&E losses at in-scope facilities. The table shows that the total national value of fishery resources lost to I&E includes $23.2 million in commercial fishing benefits, $189.4 million in recreational fishing benefits, and an unknown amount in non-use benefits ($2002, discounted at three percent). The total use value of fishery resources lost is approximately $212.5 million per year. Total commercial and recreational losses are greatest in the Mid-Atlantic region, at $8.4 million and $89.6 million, respectively, for a total use value of $97.9 million in the Mid-Atlantic region. More detailed discussions of the value of the losses in each region are provided in Sections B through H of the Regional Studies document. Additionally, as a sensitivity analysis, the Appendix to this chapter presents the value of baseline losses evaluated at a seven percent discount rate.

Table C2-2: Summary of Monetary Values of Current Impingement and Entrainment Losses (millions; $2002; 3% discount rate)

Region[a]	Use Value of I&E Losses			Non-Use Value of I&E Losses[b]	Total Value of I&E Losses
	Commercial Fishing	Recreational Fishing	Total Use Value		
California	$6.1	$7.5	$13.6	n/a	n/a
North Atlantic	$0.5	$4.9	$5.4	n/a	n/a
Mid-Atlantic	$8.4	$89.6	$97.9	n/a	n/a
South Atlantic	$1.9	$30.0	$32.0	n/a	n/a
Gulf of Mexico	$4.1	$12.4	$16.5	n/a	n/a
Great Lakes	$1.0	$29.4	$30.4	n/a	n/a
Inland	n/a	$10.6	$10.6	n/a	n/a
Total (weighted)	**$23.2**	**$189.4**	**$212.5**	**n/a**	**n/a**

[a] Regional numbers are unweighted. National totals are sample-weighted and include Hawaii.
[b] EPA estimated non-use values only qualitatively.

Source: U.S. EPA analysis, 2004.

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U.S. Environmental Protection Agency (U.S. EPA). 2004. *Regional Studies for the Final Section 316(b) Phase II Existing Facilities Rule*. EPA-821-R-04-006. February 2004.

Appendix to Chapter C2

This appendix summarizes the monetary values of current I&E losses using a 7 percent social discount rate instead of a 3 percent rate. The results of this sensitivity analysis are presented in Table C2-A-1.

Table C2-A-1: Summary of Monetary Values of Current I&E Losses (millions; $2002; 7% discount rate)

Region[a]	Use Value of I&E Losses			Non-Use Value of I&E Losses[b]	Total Value of I&E Losses
	Commercial Fishing	Recreational Fishing	Total Use Value		
California	$4.4	$6.1	$10.5	n/a	n/a
North Atlantic	$0.4	$4.3	$4.7	n/a	n/a
Mid-Atlantic	$7.3	$82.5	$89.9	n/a	n/a
South Atlantic	$1.7	$28.1	$29.8	n/a	n/a
Gulf of Mexico	$3.4	$11.2	$14.6	n/a	n/a
Great Lakes	$0.9	$26.7	$27.6	n/a	n/a
Inland	n/a	$9.5	$9.5	n/a	n/a
Total (weighted)	**$18.9**	**$172.9**	**$191.8**	**n/a**	**n/a**

[a] Regional numbers are unweighted. National totals are sample-weighted and include Hawaii.
[b] EPA estimated non-use values only qualitatively.

Source: U.S. EPA analysis, 2004.

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Chapter C3: Monetized Benefits

Introduction

This chapter summarizes the regional and national benefits of the Final Section 316(b) Phase II Existing Facilities Rule. For a discussion of regional and national baseline losses, see Chapter C2 of this document.

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Greater detail on the methods and data used in the regional analyses are provided in Chapter C1 of this EBA and in the Regional Study Document (U.S. EPA, 2004): the methods used to estimate impingement and entrainment (I&E) are described in Chapter A5; the methods used to estimate the value of the benefits of prevented I&E losses are described in Chapters A9 through A15; the results of the regional analyses are presented in Parts B through H; and a summary of national benefits is provided in Part I.

C3-1 Expected Reductions in I&E

In order to estimate the benefits of the final Phase II rule, EPA estimated the percentage reductions in I&E that will be achieved by implementing the final rule at each in-scope facility. These estimates reflect 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 I&E that the Agency believes would result from technologies adopted to comply with the rule. EPA used these estimates to calculate the average reduction in I&E expected in each region.

Table C3-1 presents average regional expected reductions in I&E. The table also presents estimates of regional and national prevented I&E losses, expressed as (1) age-one equivalents lost, (2) fishery yield foregone, and (3) biomass production foregone. The table shows that, at the 554 national in-scope facilities, the final rule reduces age-one equivalent losses by 1.4 billion fish, prevents 64.9 million pounds of fishery yield from being lost, and prevents 217.1 million pounds of future biomass production from being lost. The expected reductions vary across the regions. Facilities in the Gulf of Mexico are expected to make the largest average percentage reductions in impingement (59.0 percent), and facilities in the Mid-Atlantic are expected to make the largest average percentage reductions in entrainment (47.9 percent). More than half of the age-one equivalent losses prevented by the final rule, 846.4 million fish, are attributable to facilities in the Mid-Atlantic region. The final rule prevents the most losses of fishery yield in the Mid-Atlantic region, and prevents the most losses of future biomass production in the North Atlantic region. More detailed discussions of regional benefits are provided in Sections B through H of the Regional Study Document.

Table C3-1: Expected Reduction in I&E Under the Final Rule, by Region

Region[a]	Expected Reductions in I&E Under Final Rule				
	Impingement	Entrainment	Age-One Equivalents (millions)	Foregone Fishery Yield (million lbs)	Biomass Production Foregone (million lbs)
California	30.9%	21.0%	66.4	6.1	9.2
North Atlantic	43.8%	29.1%	19.3	0.4	84.3
Mid-Atlantic	53.5%	47.9%	846.4	34.3	54.7
South Atlantic	43.7%	17.1%	76.7	5.3	6.3
Gulf of Mexico	59.0%	31.9%	89.6	13.8	16.5
Great Lakes	51.5%	40.1%	159.5	1.7	8.5
Inland	47.2%	16.4%	116.8	1.1	20.9
Total (weighted)	**n/a**	**n/a**	**1,420.2**	**64.9**	**217.1**

[a] Regional estimates are unweighted. National totals are sample-weighted and include Hawaii. Hawaii benefits are calculated based on average expected reductions per MGD in the North Atlantic, Mid Atlantic, Gulf of Mexico, and California regions, and the total intake flow in Hawaii.

Source: U.S. EPA analysis, 2004.

C3-2 Regional and National Social Benefits

In total, EPA found 554 facilities to be in scope of the final Phase II rule. However, the regional estimates of benefits under the final rule reflect only the 540 in-scope facilities that completed section 316(b) questionnaires (excluding three facilities in Hawaii). In order to calculate national benefits for all 554 facilities, including the three facilities located in Hawaii and the eleven other facilities that did not complete the questionnaire, EPA extrapolated benefits from other facilities and regions, based on intake flows and a set of statistical weights. See Chapter I1 of the Regional Studies document for a more detailed discussion of this extrapolation procedure.

As mentioned in Chapter A12, EPA estimated non-use benefits only qualitatively. As a result, the Agency was not able monetize benefits for 98.2% of the age-one equivalent losses of all commercial, recreational, and forage species for the section 316(b) Phase II regulation. This means that the estimates of benefits presented in this section represent the benefits associated with less than 2% of the total age-one equivalents lost due to impingement and entrainment by cooling water intake structures (CWISs) and should be interpreted with caution. See Chapter A9 of the Regional Case Study document for a detailed description of the ecological benefits from reduced I&E.

Table C3-2 shows EPA's estimates of the monetary value of the I&E reductions presented in Table C3-1. The table shows that the final rule results in national use benefits of $82.9 million per year ($2002, discounted at three percent) and an unknown amount of non-use benefits. Recreational fishing benefits, which are $79.3 million, make up the majority of total national use benefits. National commercial benefits are relatively small, at $3.5 million. The final rule is expected to generate the largest commercial and recreational benefits in the Mid-Atlantic region ($1.7 million and $43.4 million, respectively), resulting in total use benefits in the Mid-Atlantic region of $45.0 million. More detailed discussions of regional benefits are provided in Sections B through H of the Regional Study Document. Additionally, as a sensitivity analysis, the Appendix to this chapter presents the value of the benefits of the final rule evaluated at a seven percent discount rate.

Table C3-2: Summary of Social Benefits (millions; $2002; 3% discount rate)[a]

Region[a]	Use Benefits of I&E Reductions			Non-Use Benefits of I&E Reductions[c]	Total Benefits of I&E Reductions
	Commercial Fishing	Recreational Fishing	Total Use Benefits		
California	$0.5	$2.5	$3.0	n/a	n/a
North Atlantic	$0.1	$1.4	$1.4	n/a	n/a
Mid-Atlantic	$1.7	$43.4	$45.0	n/a	n/a
South Atlantic	$0.2	$6.9	$7.1	n/a	n/a
Gulf of Mexico	$0.7	$6.2	$6.9	n/a	n/a
Great Lakes	$0.2	$14.0	$14.1	n/a	n/a
Inland	n/a	$3.0	$3.0	n/a	n/a
Total (weighted)	**$3.5**	**$79.3**	**$82.9**	**n/a**	**n/a**

[a] Discounted to account for lag in implementation and lag in time required for fish lost to I&E to reach a harvestable age.
[b] Regional numbers are unweighted. National totals are sample-weighted and include Hawaii.
[c] EPA estimated non-use values only qualitatively.

Source: U.S. EPA analysis, 2004.

REFERENCES

U.S. Environmental Protection Agency (U.S. EPA). 2004. *Regional Studies for the Final Section 316(b) Phase II Existing Facilities Rule*. EPA-821-R-04-006. February 2004.

Appendix to Chapter C3

This appendix summarizes the monetary benefits of the final rule using a seven percent social discount rate instead of a three percent rate. The results of this sensitivity analysis are presented in Table C3-A-1.

Table C3-A-1: Summary of Social Benefits (millions; $2002; 7% discount rate)[a]

Region[a]	Use Benefits of I&E Reductions			Non-Use Benefits of I&E Reductions[c]	Total Benefits of I&E Reductions
	Commercial Fishing	Recreational Fishing	Total Use Benefits		
California	$0.4	$1.9	$2.3	n/a	n/a
North Atlantic	$0.1	$1.2	$1.2	n/a	n/a
Mid-Atlantic	$1.5	$38.5	$39.9	n/a	n/a
South Atlantic	$0.2	$6.2	$6.4	n/a	n/a
Gulf of Mexico	$0.6	$5.5	$6.2	n/a	n/a
Great Lakes	$0.2	$12.2	$12.4	n/a	n/a
Inland	n/a	$2.6	$2.6	n/a	n/a
Total (weighted)	**$3.0**	**$70.0**	**$72.9**	**n/a**	**n/a**

[a] Discounted to account for lag in implementation and lag in time required for fish lost to I&E to reach a harvestable age.
[b] Regional numbers are unweighted. National totals are sample-weighted and include Hawaii.
[c] EPA estimated non-use values only qualitatively.

Source: U.S. EPA analysis, 2004.

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Chapter D1: Comparison of Costs and Benefits

INTRODUCTION

This chapter summarizes total private costs, develops social costs, and compares total social costs to total monetized benefits of the final rule at the national level. This chapter also presents a comparison of benefits and costs at the regional level.

Table D1-1 shows compliance action assumptions for the final rule based on each facility's currently installed technologies , 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* of this EBA presents additional information on compliance responses under the final rule.

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Table D1-1: Number of Facilities by Compliance Action[a]

Facility Compliance Action	Final Rule
No compliance action[b]	200
Impingement controls only	149
Impingement and entrainment controls	205
Flow reduction technology	0
Total	554

[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.
[b] These facilities already meet their compliance requirements. 75 facilities have a cooling tower in the baseline.

Source: U.S. EPA analysis, 2004.

D1-1 SOCIAL COSTS

This section develops EPA's estimates of the costs to society associated with the final 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 final regulation, EPA relied first on the estimated costs to facilities for the labor, equipment, material, and other economic resources needed to comply with the final 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 construction outages – 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 for 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 final regulation. *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 final Phase II rule are $249.5 million, based on a seven percent discount rate (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 $385.1 million. EPA estimates that state implementation costs for the final rule are $4.0 million annually and that federal implementation costs are approximately $64,000. The estimated total social costs of the Final Phase II Existing Facilities Rule are therefore $389.2 million, based on a seven percent discount rate.

Table D1-2 summarizes the total private and social costs of the final rule, discounted at a seven percent rate. As a sensitivity analysis, the Appendix to this chapter presents total social costs discounted at a three percent discount rate.

[1] Costs incurred by government facilities and cooperatives are not adjusted for taxes, since these facilities are not subject to income taxes.

Table D1-2: Total Private and Social Costs of Compliance by Option (millions; $2002)					
Option	**Total Private Compliance Costs to Facilities (Post-tax)**	**Social Costs[a]**			
		Pre-Tax Compliance Costs to Facilities	**State Implementation Costs**	**Federal Implementation Costs**	**Total Social Costs**
Final Rule *Alternative less stringent requirements based on both costs and benefits are allowed.*	$249.5	$385.1	$4.0	$0.06	**$389.2**

[a] All costs were annualized and discounted using a 7 percent rate.

Source: *U.S. EPA analysis, 2004.*

D1-2 Summary of National Benefits and Social Costs

The summary of national benefit estimates for the final rule is reported in *Chapter C3: Monetized Benefits*. Table D1-3 presents EPA's national social cost and benefit estimates for the final Phase II rule. The benefits estimates in Table D1-3 were discounted using a 3 percent social discount rate (as a sensitivity analysis, the Appendix to this chapter presents total social benefits discounted at a seven percent discount rate). The table shows that estimated use benefits of the final rule are less than the social costs by $306 million. As noted in Chapter C3, the use benefits estimate includes monetized benefits to commercial and recreational fishing; however, since non-use benefits were estimated only qualitatively, the net benefits estimate presented here does not include non-use benefits. EPA notes that the Agency was not able to directly monetize benefits for 98.2% of the age-one equivalent losses of all commercial, recreational, and forage species for the section 316(b) Phase II regulation. This means that the benefits estimate used in this analysis represents the benefits associated with less than 2% of the total age-one equivalents lost due to impingement and entrainment by cooling water intake structures (CWIS) and should be interpreted with caution.

Table D1-3: Total National Social Costs, Benefits, and Net Benefits by Option (millions; $2002)[a]					
Option	**Total Social Benefits[b]**			**Total Social Costs**	**Net Benefits Based on Use Benefits[c]**
	Use Benefits	**Non-use Benefits**	**Total Benefits**		
Final Rule *Alternative less stringent requirements based on both costs and benefits are allowed.*	$82.9	n/a	n/a	$389.2	**($306.3)**

[a] Benefits were discounted using a 3 percent social discount rate; costs were annualized and discounted using a 7 percent rate.
[b] Use benefits presented in this table include commercial and recreational use benefits. Because EPA did not estimate non-use benefits quantitatively, the monetary value of total benefits could not be calculated.
[c] The net benefits measure presented in this table is calculated by subtracting total social costs from total use benefits. This calculation is based on a comparison of a partial measure of social benefits with a complete measure of social costs and should be interpreted with caution.

Source: *U.S. EPA analysis, 2004.*

D1-3 Regional Comparison of Benefits and Social Costs for the Final Rule

This section presents three measures that compare the monetized benefits and costs of the final rule at the regional level: (1) a benefit-cost analysis, including net benefits and benefit-cost ratio; (2) an analysis of the costs per age-one equivalent fish saved (equivalent to a cost-effectiveness analysis); and (3) a break-even analysis of the minimum non-use benefits required for total annual benefits to equal total annualized costs, on a per household basis. For each measure, benefits were discounted using a 3 percent social discount rate, while costs were annualized and discounted using the OMB Circular rate of 7 percent. EPA also conducted a sensitivity analysis, using a 7 percent discount rate for benefits and a 3 percent discount rate for costs, which is presented in the Appendix to this chapter. Each comparison measure is presented by study region.

D1-3.1 Benefit-Cost Analysis

The benefit-cost analysis compares total annualized monetized use benefits of the final rule to total social costs. The cost estimates include costs of compliance to facilities subject to the final rule as well as administrative costs incurred by state and local governments and by the federal government. As mentioned above, the benefits estimates include monetized benefits to commercial and recreational fishing, but do not include non-use benefits, which may be large (see Chapter C3 of this document for detailed benefits results). Thus, this analysis involves a comparison of a partial measure of social benefits with a complete measure of social costs and should be interpreted with caution. Table D1-4 below summarizes the benefits and costs of the final rule and presents the net benefits and the benefit-cost ratios, by study region.

Table D1-4: Summary of Annualized Social Benefits and Costs (millions; $2002)[a]

Study Region[b]	Total Social Benefits[c]			Total Social Costs[d]	Net Benefits (Based on Use Benefits)[e]	Benefit-Cost Ratio (Based on Use Benefits)[e]
	Use Benefits	Non-use Benefits	Total Benefits			
California	$3.0	n/a	n/a	$31.7	($28.7)	0.09
North Atlantic	$1.4	n/a	n/a	$13.3	($11.9)	0.11
Mid-Atlantic	$45.0	n/a	n/a	$62.6	($17.5)	0.72
South Atlantic	$7.1	n/a	n/a	$9.0	($1.9)	0.79
Gulf of Mexico	$6.9	n/a	n/a	$22.8	($15.9)	0.30
Great Lakes	$14.1	n/a	n/a	$58.7	($44.6)	0.24
Inland	$3.0	n/a	n/a	$170.1	($167.2)	0.02
U.S. Total	**$82.9**	**n/a**	**n/a**	**$389.2**	**($306.3)**	**0.21**

a Benefits were discounted using a 3 percent social discount rate; costs were annualized and discounted using a 7 percent rate.
b Regional benefit and cost estimates are unweighted; total national estimates are sample-weighted and include costs and benefits for Hawaii.
c Use benefits presented in this table include commercial and recreational use benefits. Because EPA did not estimate non-use benefits quantitatively, the monetary value of total benefits could not be calculated.
d U.S. total annualized costs include $4.0 million in State and local administrative costs, and $0.06 in Federal administrative costs, that cannot be attributed to individual study regions.
e The net benefits measure presented in this table is calculated by subtracting total social costs from total use benefits. The benefit-cost ratio is calculated by dividing total use benefits by total social costs. These calculations are based on a comparison of a partial measure of social benefits with a complete measure of social costs and should be interpreted with caution.

Source: U.S. EPA analysis, 2004.

Table D1-4 shows that the estimated total use benefits of the final rule are not projected to exceed total social costs in any of the regions. Without accounting for non-use values, the net social costs of the final rule are smallest in the South Atlantic region ($1.9 million) and largest in the Inland region ($167.2 million). Benefit-cost ratios are highest in the Mid-Atlantic and South Atlantic regions (0.7 and 0.8, respectively) and lowest in the Inland, California, and North Atlantic regions (0.02, 0.09, and 0.11 respectively). At the national level, EPA projects total social costs to exceed total use benefits, resulting in net benefits of -$306.3 million and a benefit-cost ratio of 0.2.

The Agency points out that EPA has produced a comparison of complete costs and incomplete benefits in the benefits cost analysis of the final section 316(b) regulation. A comparison of complete costs and incomplete benefits does not provide an accurate picture of net benefits to society. The regulation is expected to provide many benefits that were not accounted for in the benefits analysis by reducing impingement and entrainment (I&E) losses of fish, shellfish, and other aquatic organisms and, as a result, increase the numbers of individuals present, increase local and regional fishery populations (a subset of which was accounted for in the benefits analysis), and ultimately contribute to the enhanced environmental functioning of affected waterbodies (rivers, lakes, estuaries, and oceans) and associated ecosystems (see Chapter A9 of the Regional Case Study document for a detailed description of the ecological benefits from reduced I&E). The Agency believes that the economic welfare of human populations is expected to increase as a consequence of the improvements in fisheries and associated aquatic ecosystem functioning due to the final section 316(b) Phase II regulation.

D1-3.2 Cost per Age-One Equivalent Fish Saved – Cost-Effectiveness Analysis

EPA also analyzed the cost per organism saved as a result of compliance with the final rule. This analysis estimates the cost-effectiveness of the rule, by study region. Organisms saved are measured as "age-one equivalents" (the number of individuals of different ages impinged and entrained by facility intakes expressed as age-one). The costs used in this comparison are the annualized social costs of the final rule.

Table D1-5 below shows that the estimated cost per age-one equivalent ranges from seven cents in the Mid Atlantic region to $1.46 in the Inland region. At the national level, the estimated cost is 27 cents per age-one equivalent saved.[2]

Table D1-5: Annualized Cost per Age-one Equivalent Saved

Study Region[a]	Total Social Costs (millions; $2002)	Age-One Equivalents (millions)	Cost/Age-One Equivalent
California	$31.7	66.4	$0.48
North Atlantic	$13.3	19.3	$0.69
Mid-Atlantic	$62.6	846.4	$0.07
South Atlantic	$9.0	76.7	$0.12
Gulf of Mexico	$22.8	89.5	$0.25
Great Lakes	$58.7	159.5	$0.37
Inland	$170.1	116.8	$1.46
U.S. Total	**$389.2**	**1,420**	**$0.27**

[a] Regional benefit and cost estimates are unweighted; total national estimates are sample-weighted and include Hawaii.
[b] U.S. total annualized costs include $4.0 million in State and local administrative costs, and $0.06 in Federal administrative costs, that cannot be attributed to individual study regions.

Source: U.S. EPA analysis, 2004.

[2] It should be noted that the national numbers include costs for the three facilities in Hawaii but do not include any benefits that may result from their compliance with the final rule.

D1-3.3 Break-Even Analysis

Estimating non-use values is an extremely challenging and uncertain exercise, particularly when primary research using stated preference methods is not a feasible option (as is the case for this rulemaking). In Chapter A12 of the *Regional Analysis Document for the Final Section 316(b) Existing Facilities Rule* (U.S. EPA, 2004), EPA described possible alternative approaches for developing non-use benefit estimates based on benefits transfer and associated methods. Due to the uncertainties of providing estimates of the magnitude of non-use values associated with the final rule, this section provides an alternative approach of evaluating the potential magnitude of non-use values. The approach used here applies a "break-even" analysis to identify what non-use values would have to be in order for the final rule to have benefits that are equal to costs.

The break-even approach uses EPA's estimated commercial and recreational use benefits for the rule and subtracts them from the estimated annual compliance costs incurred by facilities subject to the final rule. The resulting value enables one to work backwards to estimate what non-use values would need to be (in terms of willingness to pay per household per year) in order for total annual benefits to equal annualized costs. Table D1-6 below provides this assessment for the seven study regions.

Table D1-6: Implicit Uncaptured Benefits - Break-Even Analysis (millions; $2002)[a]

Study Region[b]	Use Benefits	Total Social Costs[c]	Non-use Benefits Necessary to Break Even[d]	Number of Households[e]	Break-Even WTP per Household
California	$3.0	$31.7	$28.7	8,093,185	$3.55
North Atlantic	$1.4	$13.3	$11.9	3,932,827	$3.02
Mid-Atlantic	$45.0	$62.6	$17.5	9,626,354	$1.82
South Atlantic	$7.1	$9.0	$1.9	3,817,567	$0.50
Gulf of Mexico	$6.9	$22.8	$15.9	5,421,104	$2.92
Great Lakes	$14.1	$58.7	$44.6	8,628,825	$5.17
Inland	$3.0	$170.1	$167.2	20,908,109	$8.01
U.S. Total	**$82.9**	**$389.2**	**$306.3**	**60,427,971**	**$5.07**

[a] Benefits were discounted using a 3 percent social discount rate; costs were annualized and discounted using a 7 percent rate.
[b] Regional benefit and cost estimates are unweighted; total national estimates are sample-weighted.
[c] U.S. total annualized costs include $4.0 million in State and local administrative costs, and $0.06 in Federal administrative costs, that cannot be attributed to individual study regions.
[d] The non-use benefits category in this table may include some categories of use values that were not taken into account by the recreation and commercial fishing analyses.
[e] Includes anglers fishing in the region and households in abutting counties (BLS, 2000).

Source: U.S. EPA analysis, 2004.

As shown in Table D1-6 above, for total annual benefits to equal total annualized costs, non-use values per household would have to be between $0.50 in the Gulf of Mexico region and $8.01 in the Inland region. This estimate assumes that only anglers fishing in the region and households in abutting counties have non-use values for the affected resources. At the national level, the annual non-use willingness to pay per household would have to be $5.07 for total annual benefits to equal total annualized costs.

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 final rule. Social costs do not include costs that are transfers among parties but that do not represent a net cost overall.

REFERENCES

U.S. Department of Commerce, Bureau of the Census, Bureau of Labor Statistics (BLS). 2000. "Summary File 1." http://www.census.gov/Press-Release/www/2001/sumfile1.html.

U.S. Environmental Protection Agency (U.S. EPA). 2004. *Regional Studies for the Final Section 316(b) Phase II Existing Facilities Rule*. EPA-821-R-04-006. February 2004.

Appendix to Chapter D1

This appendix presents the results of the benefit-cost analysis (Section D1-3.1 above) and the break-even analysis (Section D1-3.2 above) but using a seven percent discount rate for benefits, instead of a three percent rate, and using a three percent discount rate for costs, instead of seven percent. The results of this sensitivity analysis are presented in the following tables. In the portions of this sensitivity analysis that present a three percent rate for costs, EPA discounted the total costs of the rule at three percent but annualized them at seven percent. The three percent rate is the social discount rate that is used to determine the total present value to society of the regulatory costs and benefits incurred in the future. The seven percent annualization rate reflects the real cost of capital to complying facilities.

Table D1-A-1: Summary of Annualized Social Benefits and Costs (millions; $2002)

Study Region[a]	Total Social Benefits[b]			Total Social Costs[c]	Net Benefits (Based on Use Benefits)[d]	Benefit-Cost Ratio (Based on Use Benefits)[d]
	Use Benefits	Non-use Benefits	Total Benefits			
Benefits discounted at 3 percent; costs discounted at 3 percent.						
California	$3.0	n/a	n/a	$33.1	($30.1)	0.09
North Atlantic	$1.4	n/a	n/a	$14.9	($13.5)	0.10
Mid-Atlantic	$45.0	n/a	n/a	$69.1	($24.0)	0.65
South Atlantic	$7.1	n/a	n/a	$10.1	($3.0)	0.70
Gulf of Mexico	$6.9	n/a	n/a	$25.4	($18.5)	0.27
Great Lakes	$14.1	n/a	n/a	$66.1	($51.9)	0.21
Inland	$3.0	n/a	n/a	$183.7	($180.7)	0.02
U.S. Total	**$82.9**	**n/a**	**n/a**	**$426.0**	**($343.1)**	**0.19**
Benefits discounted at 7 percent; costs discounted at 7 percent.						
California	$2.3	n/a	n/a	$31.7	($29.4)	0.07
North Atlantic	$1.2	n/a	n/a	$13.3	($12.1)	0.09
Mid-Atlantic	$39.9	n/a	n/a	$62.6	($22.6)	0.64
South Atlantic	$6.4	n/a	n/a	$9.0	($2.6)	0.71
Gulf of Mexico	$6.2	n/a	n/a	$22.8	($16.6)	0.27
Great Lakes	$12.4	n/a	n/a	$58.7	($46.4)	0.21
Inland	$2.6	n/a	n/a	$170.1	($167.6)	0.02
U.S. Total	**$72.9**	**n/a**	**n/a**	**$389.2**	**($316.2)**	**0.19**

[a] Regional benefit and cost estimates are unweighted; total national estimates are sample-weighted and include costs and benefits for Hawaii.

[b] Use benefits presented in this table include commercial and recreational use benefits. Because EPA did not estimate non-use benefits quantitatively, the monetary value of total benefits could not be calculated.

[c] U.S. total annualized costs include $4.0 million in State and local administrative costs, and $0.06 in Federal administrative costs, that cannot be attributed to individual study regions.

[d] The net benefits measure presented in this table is calculated by subtracting total social costs from total use benefits. The benefit-cost ratio is calculated by dividing use benefits by total social costs. These calculations are based on a comparison of a partial measure of social benefits with a complete measure of social costs and should be interpreted with caution.

Source: U.S. EPA analysis, 2004.

Table D1-A-2: Implicit Uncaptured Benefits - Break-Even Analysis (millions; $2002)[a]

Study Region[a]	Use Benefits	Annualized Social Costs[b]	Uncaptured Benefits Necessary to Break Even	Number of Households[c]	Break-Even WTP per Household
Benefits discounted at 3 percent; costs discounted at 3 percent.					
California	$3.0	$33.1	$30.1	8,093,185	$3.72
North Atlantic	$1.4	$14.9	$13.5	3,932,827	$3.43
Mid-Atlantic	$45.0	$69.1	$24.0	9,626,354	$2.50
South Atlantic	$7.1	$10.1	$3.0	3,817,567	$0.80
Gulf of Mexico	$6.9	$25.4	$18.5	5,421,104	$3.42
Great Lakes	$14.1	$66.1	$51.9	8,628,825	$6.02
Inland	$3.0	$183.7	$180.7	20,908,109	$8.64
U.S. Total	**$82.9**	**$426.0**	**$343.1**	**60,427,971**	**$5.68**
Benefits discounted at 7 percent; costs discounted at 7 percent.					
California	$2.3	$31.7	$29.4	8,093,185	$3.63
North Atlantic	$1.2	$13.3	$12.1	3,932,827	$3.08
Mid-Atlantic	$39.9	$62.6	$22.6	9,626,354	$2.35
South Atlantic	$6.4	$9.0	$2.6	3,817,567	$0.68
Gulf of Mexico	$6.2	$22.8	$16.6	5,421,104	$3.06
Great Lakes	$12.4	$58.7	$46.4	8,628,825	$5.37
Inland	$2.6	$170.1	$167.6	20,908,109	$8.01
U.S. Total	**$72.9**	**$389.2**	**$316.2**	**60,427,971**	**$5.23**

[a] Regional benefit and cost estimates are unweighted; total national estimates are sample-weighted.
[b] U.S. total annualized costs include $4.0 million in State and local administrative costs, and $0.06 in Federal administrative costs, that cannot be attributed to individual study regions.
[c] Includes anglers fishing in the region and households in abutting counties (BLS, 2000).

Source: U.S. EPA analysis, 2004.

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