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Economic Analysis for the Proposed Section 316(b) Rule for Phase III Facilities

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INTRODUCTION

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EPA is proposing regulations implementing section 316(b) of the Clean Water Act (CWA). This regulation is the third in a series of rulemaking actions under CWA section 316(b), addressing the environmental impacts of cooling water intake structures (CWIS). The Proposed Section 316(b) Rule for Phase III Facilities would establish national performance requirements for the location, design, construction, and capacity of CWIS at facilities subject to this regulation. The proposed national requirements would establish the best technology available (BTA) to minimize the adverse environmental impact (AEI) associated with the use of these structures. CWIS may cause AEI through several means, including impingement (where fish and other aquatic life are trapped on equipment at the entrance to CWIS) and entrainment (where aquatic organisms, eggs, and larvae are taken into the cooling system, passed through the heat exchanger, and then discharged back into the source water body).

A1-1 OVERVIEW OF POTENTIALLY REGULATED SECTORS AND FACILITIES

Facilities potentially subject to regulation under Phase III consist of the following types of facilities that employ a cooling water intake structure and are designed to withdraw two million gallons per day or more from waters of the United States: (1) existing manufacturing facilities, (2) existing electric power producing facilities with a design intake flow (DIF) of less than 50 million gallons per day (MGD), and (3) new offshore oil and gas extraction facilities. These facilities are referred to as “potential Phase III facilities.” Phase III would not include facilities regulated under Phase I (new facilities other than new offshore oil and gas extraction) or Phase II (existing power producing facilities with a DIF of 50 MGD or greater).

The remainder of this section describes the industry sectors and facilities potentially subject to Phase III regulation that were analyzed for this rulemaking. Chapters *B2: Profile of Manufacturers*, *B4: Profile of the Electric Power Industry*, and *C2:Profile of the Offshore Oil and Gas Extraction Industry* present more detailed information on the facilities potentially subject to Phase III regulation and the markets in which they operate.

Under today’s proposed rule, not all potential Phase III facilities would be subject to national categorical requirements (only those that meet the requisite flow threshold and other applicable criteria of the proposed rule). Potential Phase III facilities that are not subject to the national requirements would continue to be subject to section 316(b) requirements established by permit writers on a case-by-case basis. EPA’s analysis in this section describes all *potential* Phase III facilities, not only those that would be subject to national requirements under today’s proposed rule.

A1-1.1 Phase III Sector Information

Based on past section 316(b) rulemakings, EPA’s effluent guidelines program, and the 1982 Census of Manufactures, EPA identified two major industry segments of existing facilities for analysis in developing this regulation: (1) steam electric generators; and (2) manufacturing industries with substantial cooling water use. Steam electric generators are 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% of total cooling water intake in the United States (U.S. EPA, 2001). However, most of the intake for steam electric power producers is covered under the Phase II regulation, which applies to power producers with a DIF of 50 MGD or greater. Only power producers with a DIF of less than 50 MGD would be potentially subject to regulation under Phase III.

Beyond steam electric generators, facilities in other industry segments use cooling water in their production processes (e.g., to cool equipment, for heat quenching, etc.). EPA used information from the *1982 Census of Manufactures* to identify four major manufacturing sectors showing substantial cooling water use: (1) 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). As illustrated in Table A1-1, steam electric utilities, steam electric nonutility power producers, and the four major manufacturing sectors together account for approximately 99% of the total cooling water intake in the United States.

Table A1-1: Cooling Water Intake by Sector

Sector[a] (SIC Code)	Cooling Water Intake Flow[b]		
	Billion Gal./Yr.	Percent of Total	Cumulative Percent
Steam Electric Utility Power Producers (49)	70,000	90.9%	90.9%
Steam Electric Nonutility Power Producers (49)	1,172	1.5%	92.4%
Chemicals and Allied Products (28)	2,797	3.6%	96.0%
Primary Metals Industries (33)	1,312	1.7%	97.8%
Petroleum and Coal Products (29)	590	0.8%	98.5%
Paper and Allied Products (26)	534	0.7%	99.2%
Additional 14 Categories[c]	607	0.8%	100.0%

[a] The table is based on reported primary SIC codes.
[b] Data on cooling water use are from the *1982 Census of Manufactures*, except for traditional steam electric utilities, which are from the Form EIA-767 database, and the steam electric nonutility power producers, which are from the Form EIA-867 database. 1982 was the last year in which the Census of Manufactures reported cooling water use.
[c] 14 additional major industrial categories (major SIC codes) with effluent guidelines.

Source: U.S. DOC, 1982; U.S. DOE, 1995; U.S. DOE, 1996.

In its analysis of the manufacturing industries, EPA divided the Primary Metal Industries (SIC 33) into a Steel sector (SIC 331) and an Aluminum sector (SIC 333/335), based on the business and other operational differences in these two major industries. The resulting five manufacturing industries – (1) Paper and Allied Products, (2) Chemicals and Allied Products, (3) Petroleum and Coal Products, (4) Steel, and (5) Aluminum – comprise the "Primary Manufacturing Industries," as referred to in this chapter and elsewhere in this Economic Analysis (EA) report.

A key data source for EPA's analysis for the 316(b) Phase III regulation is the detailed questionnaire issued to a sample of facilities potentially subject to regulation under Phase III. Based on responses to a screener survey, EPA targeted the detailed questionnaire to facilities believed to be in the electric power industry and the Primary Manufacturing Industries. EPA received a number of responses from facilities with business operations in industries other than the Primary Manufacturing Industries. EPA originally believed these facilities to be non-utility electric power generators; however, inspection of their responses indicated that the facilities were better understood as cooling water-dependent facilities whose principal operations lie in businesses other than the electric power industry or the Primary Manufacturing Industries listed above. This document includes information for these facilities, referred to as the "Other Industries" or the "Other Industries" group. This document refers to the Primary Manufacturing Industries and Other Industries, collectively, as "Manufacturers."

The analysis for facilities in the Other Industries group is restricted to the sample of facilities for which EPA received surveys but which are not part of the statistically valid sample. As a result, EPA's analysis for the Other Industries group is limited to the known facilities in this group. EPA has not estimated the number of facilities in the Other Industries group that may be subject to regulation under Phase III because EPA does not believe that this number can be reliably extrapolated from the sample of known facilities in this group. However, because the statistically valid survey group of six industries (i.e., for the five Primary Manufacturing Industries and Electric Generators) reflects 99% of total cooling water withdrawals, EPA believes that few additional facilities in the Other Industries group are potentially subject to regulation under Phase III.

Although EPA was able to undertake impact analysis for the Other Industries group using only the sample of known facilities for this group, EPA believes that its analysis for the Other Industries group provides a sufficient basis for regulation development. EPA's review of the engineering characteristics of cooling water intake and use in the Other Industries group indicates that cooling water intake and use in these industries do not differ materially from cooling water intake and use in the electric power industry and the Primary Manufacturing Industries. In addition, EPA specifically analyzed the economic impacts of evaluated options on the sample facilities in the Other Industries group. For these reasons, EPA believes that its findings with respect to economic impact and practicability of this proposal are generally applicable to the full breadth of industries, including the Other Industries group, within the regulation's scope.

EPA's 2000 Section 316(b) Industry Survey collected cooling water information for 656 power producers (hereafter referred to as "Electric Generators"), 210 facilities in Primary Manufacturing Industries, and 25 additional known facilities in Other Industries determined to be subject to regulation under Section 316(b). Industry-wide, these facilities represent 671 power producers, 537 facilities in Primary Manufacturing Industries, and 29 facilities in Other Industries.[1]

- The 671 Electric Generators withdraw 79,000 billion gallons of cooling water per year. Of the 671 power producers, 554 were covered under the final Phase II rule. These 554 facilities accounted for 90.9% of total cooling water flow for Phase II and potential Phase III Electric Generators and Manufacturers (see Table A1-2). The remaining 117 facilities were considered for potential regulation in Phase III. Based on the survey, the 117 potential Phase III facilities account for approximately 392 billion gallons of cooling water per year, or 0.5% of the estimated total flow for Phase II and potential Phase III Electric Generators and Manufacturers.

- The 537 facilities in Primary Manufacturing Industries withdraw 7,208 billion gallons of cooling water per year. The 29 additional known facilities in Other Industries withdraw 292 billion gallons of cooling water per year. Overall, the Manufacturing facilities potentially subject to Phase III regulation account for approximately 8.7% of total flow for Phase II and potential Phase III Electric Generators and Manufacturers.

[1] EPA applied sample weights to the survey respondents 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). As indicated in the preceding paragraph, EPA believes that it cannot reliably extrapolate its findings on facility count, financial characteristics, and compliance cost for facilities in Other Industries beyond the sample observations. Thus, although these facilities were assigned sample weights as part of the initial sample design, EPA later set these sample weights to 1.0 – i.e., the sample facilities in Other Industries represent only themselves in the analysis. However, the sample weights for two of these Other Industries facilities were included later in the analysis and were not set to 1.0 for the current analysis. As a result, in the current analysis, the 25 sampled Other Industries facilities are described as representing 29 facilities in the broader population.

Table A1-2: Estimated Cooling Water Intake by Sector (Sample Weighted) - EPA Survey

Sector	Total		Subject to Phase II Rule			Potentially Subject to Regulation under Phase III		
	Est. No. of Facilities	Average Annual Intake Flow (bill. gallons/yr)	Est. No. of Facilities	Average Annual Intake Flow (bill. gallons/ yr)	% of Total Surveyed	Est. No. of Facilities	Average Annual Intake Flow (bill. gallons/ yr)	% of Total Surveyed
Steam Electric Power Producers	**671**	**79,100**	**554**	**78,700**	**90.9%**	**117**	**400**	**0.5%**
Primary Manufacturing Industries	**537**	**7,200**				**537**	**7,200**	**8.3%**
Chemicals and Allied Products	185	2,400				185	2,400	**2.8%**
Steel	68	1,700				68	1,700	**2.0%**
Aluminum	20	200				20	200	**0.2%**
Petroleum and Coal Products	39	500				39	500	**0.6%**
Paper and Allied Products	225	2,400				225	2,400	**2.8%**
Additional Known Facilities in Other Industries	29	300				29	300	**0.3%**
Total Surveyed	**1,237**	**86,600**	**554**	**78,700**	**90.9%**	**683**	**7,900**	**9.1%**

Source: U.S. EPA, 2000.

The six sectors analyzed for Phase III rulemaking comprise a substantial portion of all U.S. industries. As shown in Table A1-3, the six sectors combined account for almost 45,000 facilities and 3.3 million employees, and more than $1.5 trillion in sales and $150 billion in payroll. The five manufacturing sectors alone account for approximately 25% of total U.S. manufacturing sales and 15% of manufacturing employment. It should be noted, however, that only a subset of facilities in these industry sectors would be potentially subject to regulation under Phase III. In particular, Electric Generators with a DIF of 50 MGD or greater were covered under the Final Section 316(b) Phase II Rule and therefore would not be subject to regulation under Phase III. Moreover, even facilities potentially subject to regulation under Phase III would not be subject to the national categorical requirements of the proposed rule, unless they operate a CWIS and meet the other applicability criteria of this rule, including the ultimately-selected DIF threshold.

Table A1-3: Summary Economic Data for Major Industry Sectors Potentially Subject to §316(b) Regulation: Facilities, Employment, Estimated Revenue, and Payroll in Millions of 2003 Dollars[a]

Sector (SIC)	Number of Facilities[b]	Employment	Sales, Receipts, or Shipments ($ millions)	Payroll ($ millions)
Power Producers (49)[c]	22,323	835,917	$495,971	$46,381
Paper & Allied Products (26)	6,509	170,661	$74,293	$9,473
Chemicals & Allied Products (28)	12,401	1,903,013	$628,637	$78,784
Petroleum & Coal Products (29)	2,136	101,452	$226,092	$6,017
Steel (331)	993	189,343	$62,498	$9,257
Aluminum (333,335)	405	76,354	$28,994	$3,204
All §316(b) Sectors	**44,767**	**3,276,740**	**$1,516,485**	**$153,116**
Total U.S. Manufacturing	377,673	15,879,477	4,097,675	612,046
§316(b) Manufacturing Sectors as a Percent of Total U.S. Manufacturing[e]	5.9%	15.4%	24.9%	17.4%

[a] Dollar values adjusted to 2003 using the Implicit Price Deflators for Gross Domestic Product from the Bureau of Economic Analysis.
[b] Number of facilities is not available in the Annual Survey of Manufactures so was collected from the 1997 Economic Census instead.
[c] Data for Power Producers comes from the 1997 Economic Census (the last year of available data).
[d] Data are not available by SIC in the 2001 Annual Survey of Manufactures so data was collected by NAICS instead. Paper & Allied Products (SIC 26) = NAICS 3221; Chemicals & Allied Products (28) = NAICS 325 and 326; Petroleum & Coal Products (29) = NAICS 3241; Steel (331) = NAICS 3311 and 3312; Aluminum (333,5) = NAICS 3313.
[e] Only the four §316(b) manufacturing sectors (26, 28, 29, and 33) are included in the percentage. SIC 49 is not part of total U.S. manufacturing.

Sources: 1997 Economic Census: Comparative Statistics for United States 1987 SIC Basis; Annual Survey of Manufacturers, 2001.

In addition to the Electric Generators and Manufacturing sectors covered by EPA's 2000 Section 316(b) Industry Survey and discussed above, EPA also analyzed for potential regulation in Phase III new offshore oil and gas extraction facilities (also abbreviated as "new OOGE facilities"), seafood processing vessels, and offshore liquid natural gas (LNG) terminals. EPA's analysis of these facilities is discussed in *Part C: Economic Analysis for Phase III New Offshore Oil and Gas Extraction Facilities* of this EA and in the *Technical Development Document for the Proposed Section 316(b) Rule for Phase III Facilities* (U.S. EPA, 2004).

A1-1.2 Phase III Facility Information

Two of the primary parameters used to define the options evaluated by EPA are the design intake flow (DIF) of potentially regulated facilities and their waterbody type. The main DIF applicability thresholds considered by EPA in establishing the regulatory requirements of this proposal are: 2 MGD, 20 MGD, 50 MGD, 100 MGD, and 200 MGD (see section A1-2 below). In addition, several of the analyzed options also differentiate compliance requirements based on the type of waterbody from which a facility withdraws cooling water. The two main types of waterbody are (1) coastal waterbodies (including estuaries/tidal rivers, and oceans) and Great Lakes, which are generally considered of higher biological productivity and therefore more sensitive to adverse environmental impact; and (2) inland facilities (including freshwater rivers/streams and lakes/reservoirs).

Table A1-4 shows, by waterbody type and industry segment, the number of facilities potentially subject to national requirements under five the different DIF applicability thresholds, and the total DIF of all facilities potentially subject to regulation under Phase III. EPA estimates that as many as 566 existing facilities in the

Manufacturers segment (including 537 facilities in the Primary Manufacturing Industries and 29 known facilities in Other Industries), 117 existing Electric Generators, and 124 new offshore oil and gas extraction facilities are potentially subject to regulation under Phase III, based on a 2 MGD DIF applicability threshold. The number of these facilities that would be subject to national categorical requirements varies based on the option evaluated. Under each option, existing facilities with DIFs below the specified applicability threshold for that option *or* withdrawing water from a waterbody not covered by the option, would continue to be subject to permit specifications based on best professional judgment (BPJ) instead of the national categorical requirements contained in this proposal. Table A1-4 also shows that the 807 facilities potentially subject to regulation under Phase III have a total combined DIF of approximately 42 billion gallons per day. Of these facilities, a total of 158 facilities have an individual DIF of 50 MGD or greater, 73 facilities have an individual DIF of 100 MGD or greater, and 31 facilities have an individual DIF of 200 MGD or greater.

Table A1-4: Number of Potential Phase III Facilities and Design Cooling Water Intake by Industry Segment

Industry Segment	Subject to National Requirements with DIF Applicability Threshold of Greater than or Equal to					Total DIF (MGD)
	2 MGD	20 MGD	50 MGD	100 MGD	200 MGD	
All Waterbodies						
Existing Manufacturing Facilities	566	342	155	73	31	38,070
Primary Manufacturing Industries	*537*	*328*	*145*	*67*	*28*	*36,333*
Other Industries	*29*	*15*	*10*	*6*	*3*	*1,737*
Existing Electric Generators	117	51	0	0	0	2,372
New Oil & Gas Facilities[a]	124	5	3			1,349
Total	**807**	**399**	**158**	**73**	**31**	**41,791**
Coastal Waterbodies and Great Lakes						
Existing Manufacturing Facilities	119	87	52	26	15	10,745
Primary Manufacturing Industries	*110*	*79*	*47*	*23*	*13*	*9,793*
Other Industries	*9*	*8*	*5*	*3*	*2*	*952*
Existing Electric Generators	11	4	0	0	0	265
New Oil & Gas Facilities[a]	124	5	3			1,349
Total	**254**	**96**	**55**	**26**	**15**	**12,359**
Inland Waterbodies						
Existing Manufacturing Facilities	447	255	103	47	16	27,325
Primary Manufacturing Industries	*427*	*248*	*98*	*44*	*15*	*26,540*
Other Industries	*20*	*7*	*5*	*3*	*1*	*785*
Existing Electric Generators	106	47	0	0	0	2,106
New Oil & Gas Facilities	0	0	0			0
Total	**553**	**302**	**103**	**47**	**16**	**29,431**

[a] DIF for new offshore oil and gas extraction facilities is the peak DIF when all 124 new facilities are operating.

Source: U.S. EPA, 2000; U.S. EPA Analysis, 2004.

A1-2 SUMMARY OF THE PROPOSED RULE AND OTHER EVALUATED OPTIONS

In today's proposal, EPA is proposing three options for existing facilities based on DIF and source waterbody type. These options define which facilities are Phase III existing facilities that would be subject to the proposed national categorical requirements. The three proposed options would regulate:

- (1) facilities with a total design intake flow of **50 MGD or more** and located on **any source waterbody type**;
- (2) facilities with a total design intake flow of **200 MGD or more** and located on **any source waterbody type**;

- (3) facilities with a total design intake flow of **100 MGD or more** and located on **certain source waterbody types** (i.e., an ocean, estuary, tidal river/stream or one of the Great Lakes).

The proposed rule would require Phase III existing facilities to meet similar performance standards to those required in the final Phase II rule, including a 80-95% reduction in impingement mortality and a 60-90% reduction in entrainment. The proposed rule also provides for the same five compliance alternatives specified in the final Phase II rule. If a facility is a point source that uses a cooling water intake structure and has, or is required to have, an NPDES permit, but does not meet the definition of Phase III existing facility under the corresponding evaluated option (e.g., the intake is below the specified DIF/source waterbody threshold or does not meet the 25% cooling purposes threshold), it would be subject to requirements implementing section 316(b) of the Clean Water Act set by the permit director on a case-by-case basis, using best professional judgment (BPJ).

In developing this proposal, EPA evaluated several additional options based on varying flow regimes and waterbody types. Two of these options (specifically, Options 1 and 6 below) are based on applying the same performance standards and compliance alternatives as those being proposed (i.e., the final Phase II performance standards and requirements including the use of case-by-case permit determinations based on BPJ for facilities below the applicable thresholds) but using different DIF applicability thresholds. EPA also considered a number of options (specifically Options 2, 3, 4, and 7 below) that would establish different performance standards for certain groups or subcategories of Phase III existing facilities. Under these options, EPA would apply the proposed performance standards and compliance alternatives (i.e., the Phase II requirements) to the higher threshold facilities, apply the less-stringent requirements as specified below to the middle flow threshold category, and would apply BPJ below the lower threshold.

Each of the options evaluated in developing this proposed rule is described in detail below:

Option 1 ("20 MGD for All Waterbodies Option"): Facilities with a DIF of 20 MGD or greater would be subject to the performance standards and compliance alternatives proposed in today's rule. Under this option, section 316(b) requirements for existing Phase III facilities with a DIF of less than 20 MGD would be established on a case-by-case, BPJ, basis.

Option 2: Facilities with a DIF of 50 MGD or greater would be subject to the performance standards and compliance alternatives proposed in today's rule (discussed above). Facilities located on estuaries, oceans, tidal rivers or streams, or one of the Great Lakes, and with a DIF between 20 and 50 MGD (20 MGD inclusive) would be subject to the same performance standards and compliance alternatives proposed in today's rule. Facilities located on freshwater rivers and lakes with a DIF between 20 and 50 MGD (20 MGD inclusive) would have to meet the performance standards for impingement mortality only and not for entrainment. Under this option, section 316(b) requirements for existing Phase III facilities with a DIF of less than 20 MGD would be established on a case-by-case, BPJ, basis.

Option 3: Facilities with a DIF of 50 MGD or greater would be subject to the performance standards and compliance alternatives proposed in today's rule (discussed above). All facilities with a DIF between 20 and 50 MGD (20 MGD inclusive) would have to meet the performance standards for impingement mortality only and not for entrainment. Under this option, section 316(b) requirements for existing Phase III facilities with a DIF of less than 20 MGD would be established on a case-by-case, BPJ, basis.

Option 4: Facilities with a DIF of 50 MGD or greater would be subject to the performance standards and compliance alternatives proposed in today's rule (discussed above). Facilities located on estuaries, oceans, tidal rivers or streams, or one of the Great Lakes, and with a DIF between 20 and 50 MGD (20 MGD inclusive) would be subject to the same performance standards and compliance alternatives proposed in today's rule. Under this option, section 316(b) requirements for all existing Phase III facilities on freshwater rivers/streams or lakes/reservoirs and with a DIF between 20 and 50 MGD (20 MGD inclusive), and all existing Phase III facilities with a DIF of less than 20 MGD would be established on a case-by-case, BPJ, basis.

Option 5 (Proposed "50 MGD for All Waterbodies Option"): Facilities with a DIF of 50 MGD or greater would be subject to the performance standards and compliance alternatives proposed in today's rule (discussed above). Under this option, section 316(b) requirements for existing Phase III facilities with a DIF of less than 50 MGD would be established on a case-by-case, BPJ, basis.

Option 6: Facilities with a DIF of 2 MGD or greater would be subject to the performance standards and compliance alternatives proposed in today's rule (discussed above). Under this option, section 316(b) requirements for Phase III facilities with a DIF of less than 2 MGD would be established on a case-by-case, BPJ, basis.

Option 7: Facilities with a DIF of 50 MGD or greater would be subject to the performance standards and compliance alternatives proposed in today's rule (discussed above). Facilities with a DIF between 30 and 50 MGD (30 MGD inclusive) would have to meet the performance standards for impingement mortality only and not for entrainment. Under this option, section 316(b) requirements for Phase III facilities with a DIF of less than 30 MGD would be established on a case-by-case, BPJ, basis.

Option 8 (Proposed "200 MGD for All Waterbodies" Option): Facilities with a DIF of 200 MGD or greater would be subject to the performance standards and compliance alternatives proposed in today's rule (discussed above). Under this option, section 316(b) requirements for existing Phase III facilities with a DIF of less than 200 MGD would be established on a case-by-case, BPJ, basis.

Option 9 (Proposed "100 MGD for Certain Waterbodies" Option): Facilities located on estuaries, oceans, tidal rivers or streams, or one of the Great Lakes, and with a DIF of 100 MGD or greater would be subject to the performance standards and compliance alternatives proposed in today's rule (discussed above). Under this option, section 316(b) requirements for all existing Phase III facilities on freshwater rivers and streams or lakes and reservoirs, and all existing Phase III facilities with a DIF of less than 100 MGD would be established on a case-by-case, BPJ, basis.

Table A1-5 summarizes which facilities would be defined as existing Phase III facilities and which performance standards would apply under each of the options described above.

Table A1-5: Performance Standards for the Evaluated Options for Existing Facilities

<table>
<tr><th rowspan="2">Option</th><th colspan="6">Minimum DIF Defining Facilities as Existing Phase III Facilities</th></tr>
<tr><th>2 MGD</th><th>20 MGD</th><th>30 MGD</th><th>50 MGD</th><th>100 MGD</th><th>200 MGD</th></tr>
<tr><td>1</td><td>BPJ</td><td colspan="5">I&E</td></tr>
<tr><td>2</td><td>BPJ</td><td colspan="2">Estuaries, oceans, tidal waters, or one of the Great Lakes: I&E
All other waterbodies: I only</td><td colspan="3">I&E</td></tr>
<tr><td>3</td><td>BPJ</td><td colspan="2">I only</td><td colspan="3">I&E</td></tr>
<tr><td>4</td><td>BPJ</td><td colspan="2">Estuaries, oceans, tidal waters, or one of the Great Lakes: I&E
All other waterbodies: BPJ</td><td colspan="3">I&E</td></tr>
<tr><td>5</td><td colspan="3">BPJ</td><td colspan="3">I&E</td></tr>
<tr><td>6</td><td colspan="6">I&E</td></tr>
<tr><td>7</td><td colspan="2">BPJ</td><td>I only</td><td colspan="3">I&E</td></tr>
<tr><td>8</td><td colspan="5">BPJ</td><td>I&E</td></tr>
<tr><td>9</td><td colspan="4">BPJ</td><td colspan="2">Estuaries, oceans, tidal waters, or one of the Great Lakes: I&E
All other waterbodies: BPJ</td></tr>
</table>

Key:
BPJ - Best Professional Judgement
I&E - 80-95% reduction in impingement mortality and a 60-90% reduction in entrainment
I only - 80-95% reduction in impingement mortality only
Estuaries - includes tidal rivers and streams

Source: U.S. EPA Analysis, 2004.

In the remainder of this document, the discussion for existing facilities (i.e., the Manufacturers and Generators industry segments) focuses on the three proposed options listed above: the "50 MGD for All Waterbodies" option (Option 5 – also referred to as the "50 MGD All" option); the "200 MGD for All Waterbodies" option (Option 8 – also referred to as the "200 MGD All" option); and the "100 MGD for Certain Waterbodies" Option (Option 9 – also referred to as the "100 MGD CWB" option). In addition to presenting analyses for the three proposed options in the chapter texts of this document, the appendixes to the relevant chapters also present analyses for the other evaluated options (Option 1, Option 2, Option 3, Option 4, and Option 6). EPA did not conduct economic analyses for one of the options defined above (Option 7). More information on the potential costs of Option 7 can be found in the *Technical Development Document* (U.S. EPA, 2004).

This proposed rule would also address new offshore oil and gas extraction facilities. Under this part of the proposed rule, new offshore oil and gas extraction facilities that withdraw 2 MGD or more would be subject to select requirements similar to those applicable to other new facilities in the Phase I (new facility) 316(b) regulation. These requirements address intake flow velocity, proportional flow restrictions, specific impact concerns (e.g., threatened or endangered species; critical habitat; or migratory, sport, or commercial species), and information submission, monitoring, and recordkeeping. Available information indicates that it is not feasible for offshore oil and gas extraction facilities to employ closed-cycle recirculating cooling systems to reduce cooling water flow levels because such facilities have neither the physical space nor the technical capacity to install technologies such as cooling towers or other closed-cycle systems. Thus, in this proposed rule, EPA would not require new offshore oil and gas extraction facilities to reduce intake flow to a level commensurate with a closed-cycle recirculating cooling system or to use close-cycle recirculating cooling as a baseline for performance standards.

A1-3 SUMMARY OF ECONOMIC ANALYSIS RESULTS

This section presents a brief summary of the main results of EPA's economic analyses for the proposed rule. This summary includes results for the three proposed options for existing facilities and the proposed option for new facilities. More detail on each analysis, including methodology and results, is provided in later chapters of this EA.

a. Number of Facilities Subject to National Categorical Requirements

❖ ***Existing Facilities***

EPA is proposing three options for existing facilities. These three options have the same national categorical requirements, but they differ with respect to the number of existing facilities that would be subject to these requirements. Specifically, the number of regulated facilities differs as a result of (1) the design intake flow (DIF) applicability thresholds of the three options; and (2) the type of waterbodies to which the options would apply. Facilities that meet the flow/source waterbody threshold of a particular option would be subject to performance standards similar to those established in Phase II; facilities that do not meet the relevant thresholds would remain subject to permitting on a case-by-case, best professional judgment, basis.

Table A1-6 on the following page presents, by industry segment and option, (1) the number of existing facilities potentially subject to regulation under Phase III, (2) the estimated number of baseline closures, and (3) for the three proposed options, the number of existing facilities that would be subject to the proposed national categorical requirements and the number of facilities estimated to install a technology to comply with this proposal. Under each option, facilities that are not baseline closures and would not be subject to the national requirements ("Potentially Subject to Regulation" minus "Baseline Closure" minus "Subject to National Requirements – Total") are subject to permitting on a case-by-case, best professional judgment, basis.

As shown in Table A1-6, as many as 566 facilities in the Manufacturers segment (including 537 facilities in the Primary Manufacturing Industries and 29 known facilities in Other Industries) and 117 Electric Generators are potentially subject to regulation under Phase III. EPA estimates that 77 Manufacturers and three Electric Generators would be baseline closures, i.e., they would be in severe financial distress independent of regulation. In the Manufacturers segment, the 50 MGD All option would subject the largest number of facilities (136) to national categorical requirements. Of these, 103 are estimated to install a technology to comply with the proposed rule's requirements. The 200 MGD All option would subject 25 facilities in the Manufacturers segment to national categorical requirements, with 22 facilities estimated to install a technology. The 100 MGD CWB option would subject the smallest number of manufacturing facilities (19) to national categorical requirements, with 18 of these facilities estimated to install a technology. Since existing Electric Generators with a DIF of 50 MGD or greater were covered by the final Phase II rule, no Phase III Generator would be subject to the national requirements under any of the three proposed options.

Table A1-6: Phase III Existing Facility Counts, by Industry Segment and Option

Industry	Potentially Subject to Regulation	Baseline Closure	Subject to National Requirements, Excluding Baseline Closures					
			50 MGD All Option		200 MGD All Option		100 MGD CWB Option	
			Total	w/ Technology	Total	w/ Technology	Total	w/ Technology
Manufacturers	566	77	136	103	25	22	19	18
Primary Man. Industries	*537*	*73*	*127*	*97*	*23*	*20*	*17*	*16*
Other Industries	*29*	*4*	*9*	*7*	*2*	*2*	*2*	*2*
Electric Generators	117	3	0	0	0	0	0	0
Total[a]	**683**	**80**	**136**	**103**	**25**	**22**	**19**	**18**

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

Source: U.S. EPA Analysis, 2004.

❖ ***New Facilities***

EPA is proposing a 2 MGD flow threshold for new offshore oil and gas extraction facilities, the same threshold applicable to other new facilities under Phase I. EPA's analysis of new offshore oil and gas extraction facilities includes oil and gas production platforms/structures and mobile offshore drilling units (MODUs). EPA estimated the number and characteristics of new offshore oil and gas extraction facilities based on data on existing offshore oil and gas extraction facilities, collected through EPA's 316(b) survey of offshore oil and gas extraction facilities and from other sources of publicly available information, such as the Minerals Management Service.

EPA estimates that 21 new offshore oil and gas extraction platforms and 103 new MODUs would be subject to the national requirements of the proposed option, assuming a 20-year period of construction from 2007 (the assumed effective date of the rule) to 2026.

b. Economic Impacts

❖ ***Existing Facilities***

EPA identified a facility as a regulatory closure if it would have operated under baseline conditions but would fall below an acceptable financial performance level under the proposed regulatory requirements. EPA's analysis of regulatory closures is based on the estimated change in facility after-tax cash flow (cash flow) as a result of the regulation and specifically examines whether the change in cash flow would be sufficient to cause the facility's going concern business value to become negative.[2] EPA calculated the going concern value of each facility using a discounted cash flow framework in which cash flow is discounted at an estimated cost of capital. The definition of cash flow used in these analyses is after-tax free cash flow available to all capital – equity and debt. Correspondingly, the cost of capital reflects the combined cost, after-tax, of equity and debt capital. For its analysis of economic/financial impacts on the Manufacturers industry segment, EPA used 7% as a real, after-tax cost of capital.

EPA also identified facilities that would likely incur moderate financial impacts, but that would not be expected to close, as a result of the proposed rule. EPA established thresholds for two measures of financial performance

[2] This methodology applies to Manufacturing facilities only. Since Electric Generators with a DIF of 50 MGD or greater were covered by the final Phase II rule, no Phase III Generators are subject to regulation under the three proposed options.

and condition – interest coverage ratio and pre-tax return on assets – and compared the facilities' performance before and after compliance under each option with these thresholds. EPA attributed incremental moderate impacts to the rule if both financial ratios exceeded threshold values in the baseline (i.e., there were no moderate impacts in the baseline), but at least one financial ratio fell below the threshold value in the post-compliance case.

Of the 474 Manufacturing facilities potentially subject to regulation after baseline closures, EPA estimated that no facilities would close or incur employment losses as a result of the three proposed options.[3] EPA also found that none of the 474 baseline-pass facilities would incur a moderate economic impact as a result of the three proposed options.

EPA also assessed whether firms owning regulated facilities might incur a material adverse impact, based in particular on the possibility of owning more than one regulated facility. This analysis, which relied on a firm-level cost-to-revenue test, found that no firms owning Manufacturing facilities would be materially affected as a result of the proposed regulation.

For a detailed discussion of EPA's economic impact analyses for existing facilities, see *Chapter B3: Economic Impact Analysis for Manufacturers* and *Chapter B5: Economic Impact Analysis for Electric Generators*.

❖ ***New Facilities***

EPA conducted several types of economic impact analysis for the new offshore oil and gas extraction industry segment. These analyses include three analyses for platforms/structures (facility-level production value and closure analysis, facility-level barrier-to-entry analysis, and firm-level cost-to-revenue analysis) and three analyses for MODUs (facility-level closure analysis, facility-level barrier-to-entry analysis, and firm-level cost-to-revenue analysis). These analyses found no economic impact on any new offshore oil and gas extraction facility that would be subject to regulation under Phase III or any *firm* projected to build a new offshore oil and gas extraction facility that would be subject to regulation under Phase III.

For a detailed discussion of EPA's economic impact analyses for new facilities, see *Chapter C3: Economic Impact Analysis for the Offshore Oil and Gas Extraction Industry*.

c. Regulatory Flexibility Analysis

❖ ***Existing and New Facilities***

The Regulatory Flexibility Act (RFA) requires EPA to consider the economic impact a proposed rule would have on small entities. Under the three proposed options, EPA estimates that no existing small entities in the Manufacturers or Electric Generators industry segments would be subject to national categorical requirements. In the new offshore oil and gas extraction industry segment, EPA estimates that one small entity, a new offshore oil and gas extraction platform, would be subject to the national requirements of the proposed rule. EPA estimates that this entity would incur annualized, after-tax compliance costs of less than 0.1% of annual revenue. Table A1-7 outlines the total number of small entities in each industry segment, the number of small entities potentially subject to regulation under Phase III, and the estimated cost-to-revenue ratio that small entities would incur in complying with the proposed regulation. For a detailed discussion of these analyses, see *Chapter D1: Regulatory Flexibility Analysis*.

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[3] Certain sample facilities used for estimating the number of facilities potentially subject to regulation under Phase III were not included in the economic impact analysis because their questionnaire responses lacked some data needed for the economic analysis. Using revised sample weights (to reflect the removed facilities) yields an estimate of 12 fewer Manufacturing facilities (554) for the economic impact analysis than the estimated total (566) of Manufacturing facilities using all possible sample facilities. See Chapter B3 for further discussion.

Table A1-7: Summary of Small Entity Impact Ratio Ranges by Industry Segment

Industry	Total Number of Small Entities	Number of Small Entities Owning Facilities Potentially Subject to Regulation	Percentage of Small Entities Subject toRegulation	Compliance Cost/Annual Revenues		
				0-1%	1-3%	>3%
Proposed Options / 2 MGD Option						
Manufacturers	5,113	-	0.0%	-	-	-
Electric Generators	543 - 1,295	-	0.0%	-	-	-
New OOGE Facilities	24	1	4.2%	1	-	-
Total	**5,680 - 6,432**	**1**	**0.0%**	**1**	**0**	**0**

Source: U.S. EPA Analysis, 2004.

d. UMRA Analysis

❖ ***Existing and New Facilities***

Under section 202 of the Unfunded Mandates Reform Act (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. EPA's UMRA analysis for this proposed rule found the following:

- ***50 MGD for All Waterbodies option for existing facilities and proposed option for new offshore oil and gas extraction facilities:*** EPA estimates the total annualized after-tax costs of compliance for this option to be $44.8 million (2003$). All of these direct facility costs are incurred by the private sector (including 136 Manufacturing facilities and 124 new offshore oil and gas extraction facilities). No facility owned by State and local governments is subject to the national requirements under this proposed option. Additionally, State and local permitting authorities are estimated to incur $0.5 million annually to administer this option, including labor costs to write permits and to conduct compliance monitoring and enforcement activities. EPA estimates that the highest undiscounted after-tax cost incurred by the private sector in any one year is approximately $280 million in 2011.

- ***200 MGD for All Waterbodies option for existing facilities and proposed option for new offshore oil and gas extraction facilities:*** EPA estimates the total annualized after-tax costs of compliance for this option to be $21.4 million (2003$). All of these direct facility costs are incurred by the private sector (including 25 manufacturing facilities and 124 new offshore oil and gas extraction facilities). No facility owned by State and local governments is subject to the national requirements under this proposed option. Additionally, State and local permitting authorities are estimated to incur $0.1 million annually to administer this option, including labor costs to write permits and to conduct compliance monitoring and enforcement activities. EPA estimates that the highest undiscounted after-tax cost incurred by the private sector in any one year is approximately $91 million in 2010.

- ***100 MGD for Certain Waterbodies option for existing facilities and proposed option for new offshore oil and gas extraction facilities:*** EPA estimates the total annualized after-tax costs of compliance for this option to be $17.4 million (2003$). All of these direct facility costs are incurred by the private sector (including 19 manufacturing facilities and 124 new offshore oil and gas extraction facilities). No facility owned by State and local governments is subject to the national requirements under this proposed option. Additionally, State and local permitting authorities are estimated to incur $0.2 million annually to administer this option, including labor costs to write permits and to conduct compliance monitoring and enforcement activities. EPA estimates that the highest undiscounted after-tax cost incurred by the private sector in any one year is approximately $236 million in 2011.

Table A1-8 summarizes the total annualized cost and maximum one-year cost, by facility and government costs, for each of the proposed options. For a detailed discussion of these analyses, see *Chapter D2: UMRA Analysis*.

Table A1-8: Summary of UMRA Costs (in millions, 2003$)

Sector	Total Annualized Cost			Maximum One-Year Cost		
	Facility Compliance Costs	Government Implementation Costs	Total	Facility Compliance Costs	Government Implementation Costs	Total
50 MGD All Option for Existing Facilities / Proposed Option for New Facilities						
Government Sector (excl. Federal)	$0.0	$0.5	$0.5	$0.0	$2.0	$2.0
Private Sector	$44.8	n/a	$44.8	$280.3	n/a	$280.3
200 MGD All Option for Existing Facilities / Proposed Option for New Facilities						
Government Sector (excl. Federal)	$0.0	$0.1	$0.1	$0.0	$0.4	$0.4
Private Sector	$21.4	n/a	$21.4	$90.8	n/a	$90.8
100 MGD CWB for Existing Facilities / Proposed Option for New Facilities						
Government Sector (excl. Federal)	$0.0	$0.2	$0.1	$0.0	$0.8	$0.8
Private Sector	$17.4	n/a	$17.4	$235.6	n/a	$235.6

Source: U.S. EPA Analysis, 2004.

e. Energy Effects

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." 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.

EPA analyzed the potential for energy effects of the three proposed options for existing facilities and the proposed option for new offshore oil and gas extraction facilities and found that none of them would lead to adverse outcomes. From these analyses, EPA concludes that this proposal would 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 the potential energy effects of this proposal, see *Chapter D3: Other Administrative Requirements*, Section D3-7.

f. Social Costs

❖ ***Existing Facilities***

EPA calculated the social cost of the three proposed options for Manufacturers and Electric Generators using two discount rate values: 3% and 7%. At a 3% rate, EPA estimated total annualized social costs of $47.3 million for the 50 MGD All option, $22.8 million for the 200 MGD All option, and $17.6 million for the 100 MGD CWB option (all dollar values in 2003$). At a 7% rate, these values are $50.1 million, $24.1 million, and $18.3 million, respectively. The largest component of social cost is the pre-tax cost of regulatory compliance incurred by complying facilities; these costs include pilot study costs, one-time technology costs of complying with the rule, one-time costs of installation downtime, annual operating and maintenance costs, and permitting costs (initial permit costs, annual monitoring costs, and permit reissuance costs). Social cost also includes implementation costs incurred by Federal and State governments. As described above, EPA's social cost estimates exclude the cost of facilities estimated to be baseline closures.

Table A1-9 presents the total social cost for existing facilities under the three proposed options by type of cost, using 3% and 7% discount rates. As shown in the table, direct compliance cost in the Manufacturers segment accounts for the substantial majority of total social cost for existing facilities under all three proposed options. No Electric Generators would be subject to the national categorical requirements under any of the proposed options. EPA's estimate of Federal and State government costs for administering the rule is comparatively minor in relation to the estimated direct cost of regulatory compliance.

Table A1-9: Social Cost for Existing Facilities (annualized, in millions, 2003$)

	50 MGD All Option		**200 MGD All Option**		**100 MGD CWB Option**	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
Direct Compliance Cost:						
Manufacturers[a]	$46.8	$49.5	$22.6	$24.0	$17.5	$18.1
Primary Manufacturing Industries	*$42.7*	*$45.1*	*$21.7*	*$23.1*	*$16.7*	*$17.4*
Other Industries	*$4.1*	*$4.4*	*$1.0*	*$0.9*	*$0.7*	*$0.7*
Electric Generators	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total Direct Compliance Cost[a]	$46.8	$49.5	$22.6	$24.0	$17.5	$18.1
State and Federal Administrative Cost	$0.6	$0.6	$0.1	$0.1	$0.2	$0.2
Total Social Cost for Existing Facilities[a]	**$47.3**	**$50.1**	**$22.8**	**$24.1**	**$17.6**	**$18.3**

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

Source: U.S. EPA Analysis, 2004.

❖ *New Facilities*

EPA calculated the social cost for regulated new offshore oil and gas extraction facilities also using 3% and 7% discount rates. EPA estimated total annualized social costs of $3.7 million at a 3% rate and $3.0 million at a 7% rate. The largest component of social cost is the pre-tax cost of regulatory compliance incurred by complying facilities; these costs include pilot study costs, one-time technology costs of complying with the rule, one-time costs of installation downtime, annual operating and maintenance costs, and permitting costs (initial permit costs, annual monitoring costs, and permit reissuance costs). Social cost also includes implementation costs incurred by the Federal government. States are not involved in administering the permits for new offshore oil and gas extraction facilities since the oil and gas industry is permitted under General Permits at the Regional EPA level (which is part of the Federal government).

Table A1-10 presents the total social cost for new facilities under the proposed regulation by type of cost, using 3% and 7% discount rates.

Table A1-10: Social Cost for New Facilities (annualized, in millions, 2003$)

	Proposed Option	
	3%	**7%**
Direct Compliance Cost:		
MODUs	$1.9	$1.6
Platforms/Structures	$1.4	$1.1
Total Direct Compliance Cost[a]	$3.2	$2.7
State and Federal Administrative Cost	$0.4	$0.3
Total Social Cost for New Facilities[a]	**$3.7**	**$3.0**

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

Source: U.S. EPA Analysis, 2004.

❖ ***Existing and New Facilities***

EPA is proposing three flow threshold/source waterbody-based options for existing facilities and is also proposing requirements for new offshore oil and gas extraction facilities, similar to those applicable to other new facilities in Phase I. Under the 50 MGD All option for existing facilities and the proposed option for new offshore oil and gas extraction facilities, total annualized social costs are $51.0 million and $53.1 million, using 3% and 7% discount rates, respectively. Under the 200 MGD All option for existing facilities and the proposed option for new offshore oil and gas extraction facilities, total annualized social costs are $26.4 million and $27.2 million, using 3% and 7% discount rates, respectively. Under the 100 MGD CWB option for existing facilities and the proposed option for new offshore oil and gas extraction facilities, total annualized social costs are $21.3 million at both discount rates.

Table A1-11 summarizes the total social costs for existing and new facilities. For details of EPA's social cost analyses, see *Chapter E1: Summary of Social Costs*.

Table A1-11: Total Social Cost for Existing and New Facilities (annualized, in millions, 2003 $)

	50 MGD All Option / 2 MGD Option		**200 MGD All Option / 2 MGD Option**		**100 MGD CWB Option / 2 MGD Option**	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
Direct Compliance Cost:						
Existing Facilities	$46.8	$49.5	$22.6	$24.0	$17.5	$18.1
New Facilities	$3.2	$2.7	$3.2	$2.7	$3.2	$2.7
Total Direct Compliance Cost[a]	$50.0	$52.2	$25.9	$26.7	$20.7	$20.8
State and Federal Administrative Cost:						
Existing Facilities	$0.6	$0.6	$0.1	$0.1	$0.2	$0.2
New Facilities	$0.4	$0.3	$0.4	$0.3	$0.4	$0.3
Total State and Federal Administrative Cost[a]	$1.0	$0.9	$0.5	$0.5	$0.6	$0.5
Total Social Cost[a]	**$51.0**	**$53.1**	**$26.4**	**$27.2**	**$21.3**	**$21.3**

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

Source: U.S. EPA Analysis, 2004.

g. Benefit-Cost Analysis

❖ ***Existing Facilities***

The benefit-cost analysis for each option compares total annualized use benefits to total annualized pre-tax costs (social costs) for facilities that remain open in the baseline. Benefits and costs were discounted using both a 3% and 7% discount rate. The cost estimates include costs of compliance to facilities subject to regulation under Phase III as well as administrative costs incurred by State and local governments and by the Federal government. The benefits estimates include monetized benefits to commercial and recreational fishing. Total monetizable benefits include only use benefits because non-use benefits were evaluated qualitatively. Thus, the benefit-cost analysis compares a substantially complete measure of social costs with an incomplete measure of social benefits and should be interpreted bearing in mind this inconsistency.

Table A1-12 summarizes the number of facilities subject to regulation under Phase III, the number of facilities estimated to install I&E technologies, total annualized benefits, total annualized costs, and net benefits for the three proposed options. Since EPA was unable to estimate benefits for the new offshore oil and gas extraction industry segment, the benefit-cost analysis only includes existing facilities. As reported in Table A1-12, estimated costs exceed estimated use benefits under all three of the proposed options for existing facilities. Under the 50 MGD All option, 136 facilities would be subject to the national categorical requirements. Of those facilities, 103 are estimated to install technologies to reduce impingement and entrainment. Using a 3% discount rate, total costs would exceed total use benefits by $45.4 million; using a 7% discount rate, total costs would exceed total use benefits by $48.6 million. Under the 200 MGD All option, 25 facilities would be subject to the national categorical requirements, with 22 facilities estimated to require new technologies. This option yields total social costs in excess of total benefits of $21.5 million and $23.1 million, discounted at 3% and 7%, respectively. Under the 100 MGD CWB option, 19 facilities would be subject to the national categorical requirements, and 18 are estimated to install technologies. Total social costs would exceed total use benefits by $16.2 million using a 3% discount rate, and $17.2 million using a 7% discount rate. For further discussion of the benefit-cost analysis, see *Chapter E3: Comparison of Benefits and Social Costs.*

Table A1-12: Summary of Benefits and Social Costs for Existing Facilities (millions, 2003$)

Option	Number of Facilities Subject to Option	Number of Facilities Installing Technology	Annualized Use Value of I&E Reductions (Mean)[a]	Total Annualized Costs	Net Benefits (Mean)[b]
3% Discount Rate					
50 MGD All Option	136	103	$1.9	$47.3	($45.4)
200 MGD All Option	25	22	$1.3	$22.8	($21.5)
100 MGD CWB Option	19	18	$1.4	$17.6	($16.2)
7% Discount Rate					
50 MGD All Option	136	103	$1.5	$50.1	($48.6)
200 MGD All Option	25	22	$1.0	$24.1	($23.1)
100 MGD CWB Option	19	18	$1.1	$18.3	($17.2)

[a] The total monetizable value of I&E reductions includes use benefits only. EPA evaluated non-use benefits only qualitatively.

[b] Net benefits are computed by subtracting total annualized costs from total annual use benefits. The net benefits presented here are based on the comparison of a substantially complete measure of social costs with an incomplete measure of benefits and should be interpreted with caution. In addition to the mean value presented in this table, EPA also estimated a range based on low and high values (see Chapter E3).

Source: U.S. EPA Analysis, 2004.

A1-4 ORGANIZATION OF THE EA REPORT

The *Economic Analysis for the Proposed Section 316(b) Rule for Phase III Facilities* (EA) assesses the costs, economic impacts, and benefit-cost relationships of the options evaluated in developing this proposed rule. The EA consists of five parts, organized as follows:

Part A: Background Information

Chapter A1: Introduction provides a brief discussion of the regulated industry sectors and facilities, summarizes the proposed rule and other evaluated options, and presents a summary of economic analysis results.

Chapter A2: Need for the Regulation discusses the environmental impacts from operating CWIS and explains the need for this regulatory effort.

Part B: Economic Analysis for Phase III Existing Facilities

Chapter B1: Summary of Cost Categories and Key Analysis Elements for Existing Facilities summarizes the cost categories included in the economic analyses for Phase III existing facilities and describes certain elements of the analytic framework that are common to the economic analyses of Manufacturers and Electric Generators.

Chapter B2: Profile of Manufacturers presents profiles of the markets in which affected manufacturing facilities operate (SIC codes 26, 28, 29, 331, and 333/335). Each manufacturing industry profile presents an outline of domestic production, discusses market structure and competitiveness, summarizes industry-wide financial performance and condition, and characterizes facilities potentially subject to regulation under Phase III.

Chapter B3: Economic Impact Analysis for Manufacturers presents an overview of the methodology used to estimate the economic impacts incurred by Phase III manufacturing facilities under the proposed regulation and provides the impact analysis results. The chapter describes the analytic framework used to assess severe and moderate facility-level impacts associated with the proposed rule and other evaluated options. The chapter also includes a discussion of firm- and market-level impacts.

Chapter B4: Profile of the Electric Power Industry presents a profile of the market in which potentially regulated electric generators operate. The profile presents an industry overview, outlines domestic production in terms of capacity, generation and domestic distribution, characterizes facilities potentially subject to Phase III regulation, and presents an industry outlook.

Chapter B5: Economic Impact Analysis for Electric Generators assesses the expected economic effect on the Electric Generator segment of the options evaluated in developing this proposed rule. This chapter (1) describes the methodology used to estimate the private cost to Electric Generators potentially subject to regulation under Phase III and presents summary cost statistics; (2) summarizes EPA's electricity market model analysis for Electric Generators potentially subject to Phase III regulation and the electric power industry as a whole; and (3) presents an additional assessment of the magnitude of compliance costs to Electric Generators, 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. The appendix to this chapter presents the detailed methodology and results of EPA's electricity market model analysis.

Part C: Economic Analysis for Phase III New Offshore Oil and Gas Extraction Facilities

Chapter C1: Summary of Cost Categories and Key Analysis Elements for New Offshore Oil and Gas Extraction Facilities summarizes the cost categories included in the economic analyses for Phase III new facilities and describes certain elements of the analytic framework of the economic analyses of new offshore oil and gas extraction facilities.

Chapter C2: Profile of the Offshore Oil and Gas Extraction Industry presents a profile of existing offshore oil and gas production platforms and mobile offshore drilling units (MODUs) and characterizes new facilities subject to the proposed Phase III requirements. The profile summarizes the existing facilities, their associated firms, and the financial conditions of those firms. The profile also projects the number and type of new facilities estimated to begin operation over a twenty-year period.

Chapter C3: Economic Impact Analysis for the Offshore Oil and Gas Extraction Industry presents an overview of the methodology used to estimate the economic impacts potentially incurred by new offshore oil and gas extraction facilities under the proposed Phase III regulation and provides the impact analysis results. The chapter assesses the potential impacts on MODUs, platforms, and firms, including a cost-to-revenue analysis at the facility and firm levels. The chapter also presents a barrier-to-entry analysis for new facilities.

Part D: Additional Economic Analyses for Existing and New Facilities

Chapter D1: Regulatory Flexibility Analysis presents EPA's estimates of small business impacts from the proposed rule and other evaluated options.

Chapter D2: UMRA Analysis outlines the requirements for analysis under the Unfunded Mandates Reform Act and present the results of the analysis for this proposed regulation.

Chapter D3: Other Administrative Requirements presents several other analyses conducted in developing this proposed rule. These analyses address the requirements of Executive Orders and Acts applicable to this proposal.

Part E: Social Costs, Benefits, and Benefit-Cost Analysis for Existing and New Facilities

Chapter E1: Summary of Social Costs presents the social costs of the proposed rule and other evaluated options, including time profiles of direct facility costs and administrative costs.

Chapter E2: Summary of Benefits provides an overview of the regional studies used to support the benefits assessment and a summary of the analyses. The chapter also presents the results of each regional study for the proposed rule and other evaluated options. Finally, the chapter outlines the methodology used to extrapolate regional study results to develop national estimates of baseline losses from impingement and entrainment at in-scope facilities and presents monetized benefits.

Chapter E3: Comparison of Benefits and Social Costs compares total benefits to total social costs at the national and regional levels for the proposed rule and other evaluated options. This chapter includes a discussion of net benefits, an incremental analysis of net benefits, and a break-even analysis.

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Chapter A2: Need for the Regulation

INTRODUCTION

CHAPTER CONTENTS

Many cooling water intake structures (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 best technology available (BTA) has led to an inconsistent application of section 316(b). In fact, only 67 out of 683 potential Phase III existing 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).[1] In addition, EPA and the Bureau of Land Management's Minerals Management Service (MMS) could only identify one case where the potential environmental impacts of the CWIS of a new oil and gas extraction facility were considered (U.S. DOI, 2001). In a subsequent literature review, MMS did not find any information related to potential environmental impacts or I&E controls for any existing oil and gas extraction facilities (U.S. DOI, 2004).

This chapter presents information that documents the need for this regulation.

A2-1 DESCRIPTION OF ENVIRONMENTAL IMPACTS FROM CWIS

The withdrawal of cooling water by Phase III existing facilities removes tens of billions of aquatic organisms from waters of the United States each year, including plankton (small aquatic animals, including fish eggs and larvae), fish, crustaceans, shellfish, sea turtles, marine mammals, and many other forms of aquatic life. Most impacts are to early life stages of fish and shellfish.

Aquatic organisms drawn into CWIS are either impinged on components of the intake structure or entrained in the cooling water system (CWS) 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; or (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 CWS. 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 CWS, 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.

[1] This number is sample-weighted and includes manufacturing facilities and electric generators only. Facilities estimated to be baseline closures are excluded from this count and all analyses presented in this chapter. See Chapters B3 and B5 for additional information on EPA's baseline closure analyses.

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 683 existing Manufacturers and Electric Generators potentially subject to Phase III regulation impinge and entrain millions of age 1 equivalent fish annually (see Table E2-1 in *Chapter E2: Summary of Benefits* of this Economic Analysis report for further detail).

In addition to direct losses of aquatic organisms from I&E, a number of indirect, ecosystem-level effects may also occur, including (1) disruption of aquatic food webs resulting from the loss of impinged and entrained organisms that provide food for other species, (2) disruption of nutrient cycling and other biochemical processes, (3) alteration of species composition and overall levels of biodiversity, and (4) degradation of the overall aquatic environment. In addition to the impacts of a single CWIS on currents and other local habitat features, environmental degradation can result from the cumulative impact of multiple intake structures operating in the same watershed or intakes located within an area where intake effects interact with other environmental stressors.

Several factors drive the need for this proposed rule. Each of these factors is discussed in the following sections.

A2-2 LOW LEVELS OF PROTECTION AT PHASE III FACILITIES

Facilities potentially subject to Phase III regulation 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. The first subsection present information for potential Phase III existing facilities; the second subsection presents information for Phase III new facilities.

A2-2.1 Potential Phase III Existing Facilities

EPA used information from its 2000 Section 316(b) Industry Survey to characterize the 683 potential Phase III manufacturing facilities and electric generators with respect to their CWS configuration, their CWIS technologies, and their cooling system location.

a. 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. From the responses to the Industry Survey, EPA estimates that 111 of the 566 manufacturing facilities (20%) and 86 of the 117 electric generators (73%) potentially subject to regulation under Phase III operate closed-cycle cooling systems. These facilities already meet the proposed requirements under all evaluated options and therefore would not need to install additional compliance technologies. It is noteworthy that 97% of the potentially regulated Manufacturers and Electric Generators with a closed-cycle system have a design intake flow (DIF) of less than 50 MGD. Many of these facilities would have DIFs of greater than 50 MGD if they did not have closed-cycle systems. Electric Generators with a DIF of 50 MGD or greater would have been subject to the final Phase II regulation.

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 683 potentially regulated Phase III existing facilities, 70 (10%) employed fine mesh screens on at least one CWIS. These 70 facilities represented approximately 14% of the cooling water withdrawn from surface waters by potentially regulated facilities.

Table A2-1 presents the estimated number of Manufacturers and Electric Generators, by DIF category, that reported operating a closed-cycle system and other CWS configurations, respectively. For facilities that do not operate a closed-cycle system, the table also presents the types of CWIS technologies these facilities employ.

Table A2-1: Estimated Number of Manufacturers and Electric Generators by CWS Technology/Configuration and DIF Category

CWIS Technology	Design Intake Flow (MGD				
	<50	50-100	100-200	200+	Total
Closed-Cycle Systems	**192**	**3**	**2**	**1**	**198**
Other CWS Configurations[a]	**337**	**80**	**39**	**30**	**485**
Trash Rack	202	68	36	28	333
Fine Mesh Screen	42	11	3	5	61
Other Intake Screen	191	55	35	17	299
Passive Intake System	129	17	4	12	163
Fish Diversion or Avoidance System	10	7	-	2	19
Fish handling and/or Return Technology	12	3	2	7	24
Velocity Cap	1	3	-	-	4
None	13	-	-	-	13
Total	**528**	**82**	**42**	**31**	**683**

[a] Some facilities with other CWS configurations have more than one CWIS technology in place. The numbers are therefore not additive.

Source: U.S. EPA, 2000.

b. Cooling system location

Another effective approach for minimizing Adverse Environmental Impact (AEI) associated with CWIS is to locate the intake structures in areas with low abundance of aquatic life, and to 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 A2-2 shows the estimated number of potential Phase III existing facilities by the source of water from which cooling water is withdrawn. The table indicates that 50 Phase III 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 average annual intake flow of these facilities totaled 9% of the total cooling water being withdrawn by all potential Phase III facilities. Seventy-seven facilities are located on one of the Great Lakes, accounting for approximately 21% of average annual intake flow. The remaining 556 facilities (71% of flow) were reported as being located on fresh waterbodies (including freshwater stream/rivers and lakes/reservoirs).

Table A2-2: Estimated Number of Facilities and Share of Intake Flow by Source of Waterbody Type

Waterbody Type	Number of Facilities	Percent of Total	Percent of Average Annual Intake Flow
Estuary/Tidal River	39	6%	8%
Ocean	11	2%	1%
Great Lake	77	11%	21%
Freshwater Stream/River	496	73%	66%
Lake/Reservoir	60	9%	5%
Total[a]	**683**	**100%**	**100%**

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

Source: U.S. EPA, 2000.

A2-2.2 Phase III New Facilities

In general, oil and gas extraction facilities do not consider the potential environmental impacts of their CWISs. EPA and the Bureau of Land Management's Minerals Management Service (MMS) could only identify one case where the environmental impacts of a fixed offshore oil and gas extraction facility's CWIS were considered (U.S. DOE, 2001). Although plans for the Liberty Island Project in Beaufort Sea, Alaska, were put on hold in January 2002 (FR, 2002), BP Exploration (Alaska) Inc. (BPXA) had plans to locate a vertical intake pipe for a seawater-treatment plant on the south side of Liberty Island, Beaufort Sea, Alaska. The project would have had the following specifications:

- a vertical pipe with an opening of 8 feet by 5.67 feet, located approximately 7.5 feet below the mean low-water level;
- a continuous flush system discharge that pumps the seawater through the process-water system to prevent ice formation and blockage;
- recirculation pipes located just inside the opening to help keep large fish, other animals, and debris out of the intake;
- two vertically parallel screens (6 inches apart), located in the intake pipe above the intake opening, with a mesh size of 1 inch by 1/4 inch;
- maximum water velocity of 0.29 feet per second at the first screen and 0.33 feet per second at the second screen (maximum velocities only during a few hours each week while testing the fire-control water system – at other times, considerably lower velocities); and
- periodical removal, cleaning, and replacement of the screens.

MMS stated in the Liberty Draft Environmental Impact Statement (which was prepared prior to BP's decision to hold development plans) that the proposed seawater-intake structure would likely harm or kill some young-of-the-year arctic cisco during the summer migration period and some eggs and fry of other species in the immediate vicinity of the intake. However, MMS estimated that less than 1% of the arctic cisco in the Liberty area would likely be harmed or killed by the intake structure. Further, MMS concluded that the intake structure (1) would not have a measurable effect on young-of-the-year arctic cisco in the migration corridor and (2) would not have a measurable effect on other fish populations because of the wide distribution/low density of their eggs and fry.

In general, the importance of controlling I&E at offshore oil and gas extraction facilities is highlighted by the fact that these structures provide an important fish habitat. For example, oil and gas platforms and artificial reefs undoubtedly serve as red snapper habitat, and they may serve as an important (but not obligate) link in the life history of both juvenile and adult red snapper (Gulf of Mexico Fishery Management Council, 1996). In general, five to 100 times more fish can be concentrated near offshore platforms than in the soft mud and clay habitats elsewhere in the Gulf of Mexico (Fury, 2002). As a result, 70% of all fishing trips in the Gulf of Mexico head for oil and natural gas platforms. Likewise, 30% of the 15 million fish caught by recreational fishermen every year off the coasts of Texas and Louisiana come from the waters around platforms.

A2-3 REDUCING ADVERSE ENVIRONMENTAL IMPACTS

Multiple types of AEI result from 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.

The main purpose of this regulation is to minimize environmental impacts such as those described above. See *Part E: Social Costs, Benefits, and Benefit-Cost Analysis for Existing and New Facilities* of this EA for information on estimated reduction in I&E as a result of this proposed rule and alternative evaluated options. See also the *Regional Benefits Assessment for the Proposed Section 316(b) Rule for Phase III Facilities* (U.S. EPA, 2004) for detailed information on baseline losses.

A2-4 ADDRESSING MARKET IMPERFECTIONS

Facilities withdraw cooling water from U.S. waters 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 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 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.

A2-5 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 A2-3 illustrates a variety of ways in which States identify the section 316(b) requirements.

Table A2-3: 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, no mechanism currently exists 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).

A2-6 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.

Another set of uncertainties 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 316(b) requirements 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 B1: Summary of Cost Categories and Key Analysis Elements for Existing Facilities

CHAPTER CONTENTS

INTRODUCTION

This chapter presents an overview of the cost categories and certain elements of the analytic framework that are common to the economic analyses of the two major industry segments analyzed in developing the proposed standards for Phase III existing facilities: Manufacturers and Electric Generators.

B1-1 COST CATEGORIES

In its analyses of the costs and economic impacts of the proposed rule on Phase III existing facilities, EPA considered four categories of costs:

1. costs of installing and operating compliance technology,
2. net income loss from installation downtime,
3. administrative costs incurred by complying facilities, and
4. administrative costs incurred by permitting authorities.

The following discussion provides an overview of each of these cost categories, addressing those aspects of each categories that is common to the analyses of Manufacturers and Electric Generators. This discussion provides greater depth in its treatment of the two administrative cost categories as the application of these two categories is essentially the same for both industry segments. Additional detail on the costs of installing and operating compliance technology and the net income loss from installation downtime is provided in the *Technical Development Document for the Proposed Section 316(b) Rule for Phase III Facilities* (hereafter referred to as the *"Phase III Technical Development Document*"; U.S. EPA, 2004b) and Chapters *B3: Economic Impact Analysis for Manufacturers* and *B5: Economic Impact Analysis for Electric Generators*.

It should be noted that this chapter addresses cost components relevant for the proposed rule as well as other options analyzed in developing this proposal. As a result, some of the concepts are not relevant to the three proposed options for existing facilities, which do not regulate Electric Generators.

B1-1.1 Costs of Installing and Operating Compliance Technology

Facilities that are not currently in compliance with the performance standards for Phase III existing facilities would need to implement technologies to reduce impingement mortality and/or entrainment. The specific technologies projected by EPA for the analyzed facilities depend on the performance standard each facility would need to meet (based on the waterbody type, design intake flow, capacity utilization, and annual intake flow as a percent of source waterbody mean annual flow) and the facility's baseline technologies in-place. A list of the technologies considered for this analysis is provided in Table B1-1 below.

EPA then developed technology cost estimates for the proposed rule based on the impingement mortality and entrainment reduction technologies projected for each potential existing Phase III facility. Technology costs include capital costs and operating and maintenance (O&M) costs. The annual O&M cost estimates used in the cost modules are the *net* O&M costs, which are defined as the difference between the estimated baseline O&M costs and the incremental compliance O&M costs. O&M costs are further differentiated into fixed and variable O&M costs. Fixed O&M costs do not vary with the level of production (i.e., they are incurred even when a business unit is periodically shut down). EPA assumes any periodic maintenance tasks (e.g., changing screens, changing nets, or inspection/cleaning by divers) are performed regardless of plant operation, and therefore are considered fixed costs. Variable O&M costs do vary with the level of production and are allocable based on estimated intake operating time (e.g., annual labor estimates for passive screens include increased labor for several weeks during high debris episodes). The actual fixed and variable portions of O&M costs for each facility may vary depending on the mix of baseline and compliance technologies. The technology costs developed for the proposed rule analysis are engineering cost estimates, expressed in July 2002 dollars (see Section B1-2.2 below for a discussion of adjusting monetary values to a common time period of analysis).

More detailed information on the compliance technologies considered by EPA, on technology costs, and on EPA's characterization of baseline technologies already in-place at potential Phase III existing facilities is available in the Phase III Technical Development Document (U.S. EPA, 2004b).

B1-1.2 Net Income Loss from Installation Downtime

Installation of some of the compliance technologies considered for potential Phase III existing facilities would require a one-time, temporary downtime of the facility's cooling water intake system. Table B1-1, below, lists the estimated durations of net system downtime, in weeks, for each of the compliance technology modules considered for compliance with the proposed standards. The lower end of the range is used at lower flow rates.

Table B1-1: Estimated Average Downtime for Technology Modules

Description	Net Downtime (Weeks)
Fish handling and return system	0
Fine mesh traveling screens with fish handling and return	0
New larger intake structure with fine mesh, handling and return	2 - 4
Passive fine mesh screens with 1.75 mm mesh size at shoreline	9 - 11
Fish barrier net	0
Relocate intake to submerged offshore with passive fine mesh screen with 1.75 mm mesh size	9 - 11
Velocity cap at inlet of offshore submerged	0
Passive fine mesh screen with 1.75 mm mesh size at inlet of offshore submerged	0
Double-entry, single-exit with fine mesh and fish handling and return	0
Passive fine mesh screens with 0.75 mm mesh size at shoreline	9 - 11
Relocate intake to submerged offshore with passive fine mesh screen with 0.75 mm mesh size	0
Passive fine mesh screen at inlet of offshore submerged with 0.75 mm mesh size	9 - 11

Source: U.S. EPA Analysis, 2004.

The "net" downtime duration accounts for any expected annual period of cooling water system downtime for regular maintenance and repair – the net downtime is the number of weeks the cooling water system would need to be out of service above and beyond any regular maintenance downtime period. EPA assumed that facilities would minimize the disruption to their operations by making the required technology upgrades during these periods of scheduled maintenance. Scheduled maintenance periods 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 annual maintenance downtime would be four weeks.

During the downtime period, the facility's cooling-water dependent operations would most likely be halted, with a potential loss of revenue and income from those operations. Accordingly, a key element of the cost to facilities in complying with the proposed standards for Phase III existing facilities is the loss in income from installation downtime. In the facility impact analyses, EPA accounted for the cost of installation downtime as the loss in pre-tax income in the facility's affected business operations. The cost of installation downtime is accounted for as a loss in revenue offset by a reduction in variable costs in the affected business operation plus any increase in operating costs due to temporary removal of the cooling water intake system from service.

The cost and impact analysis discussions for the two major industry segments potentially affected by the proposed standards for Phase III existing facilities provide additional detail on the calculation of the cost of installation downtime (see Chapters B3 and B5).

B1-1.3 Administrative Costs for Complying Facilities

Compliance with the standards of the proposed rule requires Phase III existing facilities to carry out certain administrative functions, which help them determine their compliance requirements and provide the documentation needed for issuance of their new National Pollution Discharge Elimination System (NPDES) permits. These administrative functions 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).

a. Initial post-promulgation NPDES permit application

The proposed rule requires Phase III 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 (CWIS) permitting procedures, regardless of the proposed standards for Phase III existing facilities, but are still included in EPA's compliance cost estimate; therefore, the permitting costs presented in this economic analysis 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 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 some facilities to conduct a comprehensive demonstration study.[2] 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:

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

[2] For more information on the Comprehensive Demonstration Study, please refer to EPA's Information Collection Request (U.S. EPA, 2004a).

- ***Proposal for collection of information for comprehensive demonstration study:*** describing historical studies that would 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 the plan for review; revising the plan based on State review; and keeping records;

- ***Source waterbody flow information****:* gathering information to characterize flow (for freshwater rivers/streams only); developing a description of the thermal stratification of the waterbody (for lakes/reservoirs only); performing 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; submitting the plan for review; and keeping records;

- ***Impingement mortality and/or entrainment characterization study:*** performing biological sampling; performing impingement and entrainment monitoring; conducting laboratory analyses; profiling source water biota; identifying critical species; developing a description of additional stresses; developing a report based on study results; revising the report based on State review; and keeping records;

- ***Verification monitoring plan:*** developing a narrative description of the frequency of monitoring, parameters to be monitored, and the basis for determining the parameters and frequency and duration of monitoring; submitting data and a plan for review; revising the plan based on State review; and keeping records.

Finally, Phase III existing facilities would have to submit a plan that describes the installation, operation, and maintenance, of the technology(ies) proposed and/or implemented at the CWIS(s):

- ***Technology installation and operation plan:*** developing an installation and maintenance schedule; describing the proposed monitoring parameters; listing the technology efficacy assessment activities; developing a schedule and methodology for efficacy assessment activities; submitting plan for 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 would have to undertake depend on the facility's source water body type, whether it exceeds the capacity utilization rate (applicable to Electric Generators only) and proportional flow thresholds, and its baseline technologies in-place. Certain activities are expected to be more costly for marine facilities than for freshwater facilities.[3] Some activities would be required of all facilities, while other activities would be required only if the facility exceeds the capacity utilization rate or proportional flow thresholds.

The table shows that certain Phase III existing facilities only have to carry out a minimal set of permitting requirements (i.e., start-up activities and permit application activities). Facilities with such minimal requirements include (1) facilities that have recirculating systems in the baseline and (2) facilities that already have or are required to install certain pre-approved technologies (including cylindrical wedgewire screens) and that only have to comply with impingement requirements. Freshwater facilities that would have to meet both impingement and entrainment standards and that already have or are required to install a pre-approved technology have to develop a technology installation and operation plan and a verification monitoring plan in addition to the minimal activities. The maximum initial permitting cost is estimated to be approximately $985,000 for a facility that would have to meet both impingement and entrainment standards and that withdraws from a marine waterbody.

[3] For permitting requirements, marine facilities include those withdrawing from the Great Lakes.

Table B1-2: Cost of Initial Post-Promulgation NPDES Permit Application Activities (2003$)

Activity	Estimated Cost per Permit							
	Minimal Require-ments	Freshwater				Marine (incl. Great Lakes)		
		Pre-Appr. with I&E	I-only	E-only	I&E	I-only	E-only	I&E
Start-up activities[b]	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000
Permit application activities[a]	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000	$10,000
Proposal for collection of information for comprehensive demonstration study[b]	$0	$0	$13,000	$13,000	$13,000	$13,000	$13,000	$13,000
Source waterbody flow information[a]	$0	$0	$4,000	$4,000	$4,000	$0	$0	$0
Design and construction technology plan[a]	$0	$0	$3,000	$3,000	$4,000	$3,000	$3,000	$4,000
Impingement mortality and/or entrainment characterization study[c]	$0	$0	$354,000	$408,000	$513,000	$641,000	$747,000	$946,000
Technology installation and operation plan[a]	$0	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000
Verification monitoring plan[a]	$0	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000
Total Initial Post-Promulgation NPDES Permit Application Cost[d]	**$13,000**	**$21,000**	**$395,000**	**$449,000**	**$555,000**	**$679,000**	**$784,000**	**$985,000**

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

Key to permitting types:

Minimal requirements – Has recirculating systems in the baseline; or already has or is required to install a pre-approved technology and only has to comply with impingement requirements.
Pre-appr. with I&E – Already has or is required to install a pre-approved technology and has to comply with impingement and entrainment requirements.
I-only – Only has to comply with impingement requirements.
E-only – Only has to comply with entrainment requirements.
I&E – Has to comply with both impingement and entrainment requirements.

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 would function properly when installed and operated. EPA assumed that any facility with both I&E requirements would consider doing a pilot study, *except* if (1) the technology is sufficiently inexpensive to install ($500,000 or less) or (2) the technology is such that a scaled down version is infeasible. EPA further assumed that a pilot study would cost either $150,000 or 10% of technology installation costs, whichever is greater. 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 24 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 requirements for Phase III existing facilities, 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;

- ***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 restoration measures; submitting results for review; and keeping records.

b. Subsequent NPDES permit renewals

Each facility would have to apply for NPDES permit renewal every five years. Subsequent permit renewal applications would 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 would have to undertake depend on the facility's source water body type, whether it exceeds the capacity utilization rate (applicable to Electric Generators only) and proportional flow thresholds, and its baseline technologies in-place. Certain activities are expected to be more costly for marine facilities than for freshwater facilities. Some activities would be required of all facilities, while other activities would be required only if the facility exceeds the capacity utilization rate or proportional flow thresholds. The maximum repermitting cost is estimated to be approximately $334,000 for a facility that would have to meet both impingement and entrainment standards and that withdraws from a marine waterbody.

Table B1-3: Cost of NPDES Repermit Application Activities[a] (2003$)

Activity	Estimated Cost per Permit							
	Minimal Require-ments	Freshwater				Marine (incl. Great Lakes)		
		Pre-Appr. with I&E	I-only	E-only	I&E	I-only	E-only	I&E
Start-up activities	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000
Permit application activities	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000	$6,000
Proposal for collection of information for comprehensive demonstration study	$0	$0	$3,000	$3,000	$3,000	$3,000	$3,000	$3,000
Source waterbody flow information	$0	$0	$1,000	$1,000	$1,000	$0	$0	$0
Design and construction technology plan	$0	$0	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000
Impingement mortality and/or entrainment characterization study	$0	$0	$139,000	$170,000	$172,000	$255,000	$316,000	$320,000
Technology installation and operation plan	$0	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000	$1,000
Total Initial Post-Promulgation NPDES Permit Application Cost[b]	**$7,000**	**$9,000**	**$154,000**	**$185,000**	**$188,000**	**$269,000**	**$329,000**	**$334,000**

[a] The costs for these activities are incurred during the year prior to the permit application.
[b] Individual numbers may not add to total due to independent rounding.

Key to permitting types:

Minimal requirements	–	Has recirculating systems in the baseline; or already has or is required to install a pre-approved technology and only has to comply with impingement requirements.
Pre-appr. with I&E	–	Already has or is required to install a pre-approved technology and has to comply with impingement and entrainment requirements.
I-only	–	Only has to comply with impingement requirements.
E-only	–	Only has to comply with entrainment requirements.
I&E	–	Has to comply with both impingement and entrainment requirements.

Source: U.S. EPA, 2004a.

c. Annual monitoring, record keeping, and reporting

Annual 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; conducting laboratory analyses; performing statistical analyses, and keeping records;

- ***Bi-annual status report activities:*** reporting on inspection and maintenance activities; detailing biological monitoring results; compiling and submitting the report; and keeping records; (these activities are conducted every two years, instead of annually);

- ***Verification study:*** conducting technology performance monitoring; performing statistical analyses; submitting monitoring results and study analysis; 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 annual cost is estimated to be approximately $82,000 for a facility that would have to meet both impingement and entrainment standards and that withdraws from a marine waterbody.

Table B1-4: Cost of Annual Monitoring, Record Keeping, and Reporting Activities (2003$)

Activity	Estimated Cost per Permit							
	Minimal Require-ments	Freshwater				Marine (incl. Great Lakes)		
		Pre-Appr. with I&E	I-only	E-only	I&E	I-only	E-only	I&E
Biological monitoring for impingement	$0	$0	$19,000	$0	$19,000	$24,000	$0	$24,000
Biological monitoring for entrainment	$0	$39,000	$0	$39,000	$39,000	$0	$49,000	$49,000
Bi-annual status report activities[a]	$0	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000	$9,000
Total Annual Monitoring, Record Keeping, and Reporting Cost	**$0**	**$47,000**	**$28,000**	**$47,000**	**$66,000**	**$33,000**	**$58,000**	**$82,000**
Verification study[a]	$0	$7,000	$7,000	$7,000	$7,000	$7,000	$7,000	$7,000

[a] This is a cost that is incurred once every two years. Therefore, only half of the total report cost of approximately $17,000 is accounted for in this annual framework.
[b] This is a one-time cost incurred during the year of compliance.

Key to permitting types:
Minimal requirements – Has recirculating systems in the baseline; or already has or is required to install a pre-approved technology and only has to comply with impingement requirements.
Pre-appr. with I&E – Already has or is required to install a pre-approved technology and has to comply with impingement and entrainment requirements.
I-only – Only has to comply with impingement requirements.
E-only – Only has to comply with entrainment requirements.
I&E – Has to comply with both impingement and entrainment requirements.

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

B1-1.4 Administrative Costs for Permitting Authorities and the Federal Government

In addition, permitting authorities have to review the information provided by Phase III existing facilities and have to issue new NPDES permits that reflect the requirements of the proposed rule. These activities impose costs on the responsible governmental units.

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 would incur three types of costs associated with implementing the requirements of the proposed rule: (1) start-up activities, (2) permitting activities associated with the initial NPDES permit containing the new section 316(b) requirements and subsequent permit renewals, and (3) annual activities.[4]

Start-up costs are incurred only once by each of the 46 permitting authorities. Permitting costs and annual activities are incurred for every permit. The incremental administrative burden on States would depend on the extent of each State's current practices for regulating cooling water intake structures (CWIS). States that currently require relatively modest analysis, monitoring, and reporting of impacts from CWIS in NPDES permits may require more permitting resources to implement the proposed standards for Phase III existing facilities than are required under their current programs. Conversely, States that currently require very detailed analysis may require fewer permitting resources to implement the proposed rule than required under their current programs.

In addition to costs to permitting authorities, the Federal government is likely to incur costs to review those parts of NPDES permits associated with the compliance requirements of this rule and to ensure that the permitting authorities are implementing the rule properly.

For a detailed discussion of administrative costs for permitting authorities and the Federal government, see *Chapter D2: UMRA Analysis*, section D2-1.2.

B1-2 KEY ELEMENTS OF THE ECONOMIC ANALYSIS FOR PHASE III EXISTING FACILITIES

The economic analysis conducted in developing the proposed requirements for Phase III existing facilities addresses the cost to, and impact on, the affected industry segments and society generally. Although these analyses differ in important respects for the individual industry segments – particularly in terms of the analytic models and methods for assessing the economic/financial impact on complying parties within the segments – several elements of the analysis have features common to all Phase III existing facilities. This section reviews the following key common elements:

- Compliance Schedule
- Adjusting Monetary Values to a Common Time Period of Analysis
- Discounting and Annualization: Costs to Society or Social Costs
- Discounting and Annualization: Costs to Complying Facilities

B1-2.1 Compliance Schedule

For its analysis of the cost and impacts of the proposed rule, EPA developed a profile of the expected compliance year for each of the sample facilities considered in the economic analysis. The estimated compliance years of facilities are important for several reasons:

- First, the compliance years determine the timing of outlays by facilities and society in complying with the regulation, both for the initial outlays and for the ongoing profile of outlays in maintaining compliance with the regulation. This information is important in properly assessing the present value of the regulation's costs to society.

- Second, the profile of compliance is likewise important in understanding the time profile, and thus present value, of benefits achieved by compliance with the regulation. Explicit analysis of the compliance

[4] The costs associated with implementing the requirements for Phase III existing facilities are documented in EPA's Information Collection Request (U.S. EPA, 2004a).

schedule is particularly important for the benefits analysis because the regulation's benefits are not achieved instantly upon facilities' reaching compliance, but build up over a period of several years. Accordingly, EPA also used the compliance schedule developed for the cost and impact analysis in developing the time profile of benefits.

- Third, for Electric Generators, a high concentration of facilities out of service for technology upgrades in the same region and at the same time could lead to temporary energy effects in that region. Thus, in analyzing the potential electricity supply reliability and electricity market effects of those options under which Electric Generators would be subject to Phase III regulation, EPA accounted for the expected compliance years of Electric Generators.

EPA initially assumed that facilities would comply with the proposed requirements during the year their first post-promulgation NPDES permit is issued (based on a 5-year permit cycle, this would be 2007 to 2011). However, since some of the permitting requirements need to be performed over a three-year period prior to compliance, facilities that would be renewing NPDES permits within the first three years after promulgation of the final Phase III rule (2007 to 2009) would not comply until their second post-promulgation NPDES permit is issued (2012 to 2014). From these assumptions, EPA estimates that all facilities come into compliance between 2010 and 2014. Following research on when sample facilities' current NPDES permits would expire and thus need to be renewed, EPA developed an explicit compliance schedule for all Phase III existing facilities in the analysis.

B1-2.2 Adjusting Monetary Values to a Common Time Period of Analysis

The various economic information used in the cost and impact analyses was initially provided or estimated in dollars of different years. For example, facility financial data obtained in the 316(b) survey for Manufacturers and Electric Generators are for the years 1996, 1997, and 1998, while the technology costs of regulatory compliance were estimated in dollars of the year 2002. To support a consistent analysis using these data that were initially developed in dollars of different years, EPA needed to bring the dollar values to a common analysis year. For this analysis, EPA adjusted all dollar values to constant dollars of the year 2003 (average or mid-year, depending on data availability) using an appropriate inflation adjustment index. For adjusting compliance costs, EPA used the ***Construction Cost Index (CCI)*** published by the Engineering News-Record. For financial statement information, EPA used the ***Gross Domestic Product Implicit Price Deflator (GDP Deflator)*** to bring dollar values to 2003. In some instances, EPA used the Producer Price Index series particular to a specific industry to adjust values to a common analysis year.

a. CCI

EPA used the CCI to adjust compliance cost estimates from July 2002 to mid-year (June) 2003. EPA judges the CCI as generally reflective of the cost of installing and operating process and treatment equipment such as would be required for compliance with the options considered for this regulation. Table B1-5 shows CCI values for July, 2002 and June, 2003.

Table B1-5: Construction Cost Index

Year	Value	% Change
July 2002	6605	
June 2003	6694	1.3%

Source: ENR, 2004.

b. GDP Deflator

EPA used the GDP Deflator to adjust 316(b) survey financial data from 1996-1998 to 2003. The GDP Deflator is a quarterly series that measures the implicit change in prices, over time, of the bundle of goods and services comprising gross domestic product. Table B1-6 shows GDP Deflator values from 1996 to 2003. From 1998 to 2003, the total change in the deflator series was 9.5% (105.7/96.5).

Table B1-6: GDP Deflator Series

Year	Value	% Change
1996	93.9	
1997	95.4	1.7%
1998	96.5	1.1%
1999	97.9	1.4%
2000	100.0	2.2%
2001	102.4	2.4%
2002	103.9	1.5%
2003	105.7	1.6%

Source: U.S. DOC, 2004.

B1-2.3 Discounting and Annualization – Costs to Society or Social Costs

Discounting refers to the economic conversion of future costs (and benefits) to their present values, accounting for the fact that society tends to value future costs or benefits less than comparable near-term costs or benefits. Discounting is important when the values of costs or benefits occur over a multiple year period and may vary from year to year. Discounting is also important when the time profiles of costs and benefits are not the same – which is the case for the regulatory analysis of Phase III existing facilities. Discounting enables the accumulation of the cost and benefit values from multiple years at a single point in time, accounting for the difference in how society values those costs and benefits depending on the year in which the values are estimated to occur.

To estimate the social costs of options considered in developing the proposed requirements for Phase III existing facilities, EPA first developed a profile, over the period of analysis, of the compliance costs associated with each option. EPA defined the period of analysis as starting with the assumed date the final rule would take effect, beginning of year 2007, and extending through the latest year in which any affected facility is assumed to reach compliance (2014) *plus* a period of 30 years in which facilities are assumed to continue compliance. Thus, for the social cost analysis for Phase III existing facilities, the analysis period extends to 2043. In developing the time profile of costs, EPA assigned costs according to the following schedule:

❖ ***Direct Costs of Regulatory Compliance***

- ***Capital Costs of Compliance Technology:*** This cost is first incurred in the year that the facility's first post-promulgation permit is issued. However, the equipment for complying with the regulation is expected to have a useful life of 10 years, or a period shorter than the 30 years of compliance. Accordingly, following the first installation, facilities are assumed to reinstall, and re-incur the cost of, the compliance equipment at year 11 and year 21 of the facility-specific compliance period.

- ***Cost of Installation Downtime:*** This cost is incurred in the year that the facility installs the technology. Although the compliance technology must be reinstalled at a 10-year interval over the analysis period, the engineering analysis of compliance requirements indicates that facilities would not need to incur additional installation downtime for reinstallation of the compliance technology equipment.

- ***Compliance Technology Operation and Maintenance:*** This cost is assumed to occur in each year of a facility's 30-year compliance period.

- ***Pilot Study:*** Pilot study costs are incurred one year before the facility's first post-promulgation permit is issued.

❖ ***Administrative Costs Incurred by Complying Facilities***

- ***Impingement Mortality and Entrainment Characterization Study:*** All facilities conduct this two- or three-year study except those that already have recirculating systems in the baseline and those that already have or are installing a pre-approved technology. The cost of this study is incurred over the years immediately preceding the facility's first post-promulgation permit, but not including the first year of compliance. Facilities withdrawing from a marine waterbody (including the Great Lakes) are required to do a three-year study; facilities withdrawing from a freshwater body are required to do a two-year study.

- ***Initial Permitting Cost:*** In addition to incurring the cost of characterization studies, complying facilities would also incur an initial permitting cost, which is assigned to the first year of a facility's 30-year compliance period.

- ***Repermitting Costs:*** As explained above, facilities would need to renew their NPDES permits each five years during the period of compliance. Repermitting costs are assumed to recur at years 5, 10, 15, 20, and 25 of a facility's 30-year compliance year period. If a facility were to continue compliance beyond the assumed 30-year compliance period, it would incur an additional round of repermitting costs in year 30 of the compliance period. However, these costs would be incurred to support compliance in years beyond the 30th year of compliance, and were therefore not accounted for in this analysis.

- ***Annual Monitoring, Record Keeping, and Reporting Activities:*** This cost is assumed to occur in each year of the 30-year compliance year period.

❖ ***Administrative Costs Incurred by Permitting Authorities***

- ***One-time Start-up Costs:*** This cost is assigned to the year the rule would take effect (2007).

- ***Permit Processing Costs:*** These costs are assigned to the years in which facilities apply for initial permits or renewal permits during the compliance period.

- ***Annual Permit Administration Activities:*** The cost of these activities is assumed to occur in parallel with the annual permit-related activities by complying facilities and thus occurs in each year of a facility's compliance period.

❖ ***Administrative Costs Incurred by the Federal Government***

- ***Permit Review:*** The Federal government is assumed to review the first permit for each Phase III existing facility that would include the new 316(b) requirements specified in this rule. Federal administrative costs would therefore be incurred between 2010 and 2014.

For each option analyzed, EPA assigned costs by facility and governmental unit according to this framework and then summed these costs on a year-by-year basis over the total time period of analysis. For the social cost analysis, these costs were tallied on a pre-tax basis, which differs from the treatment of costs for the facility impact analysis as described below. These profiles of costs by year were then discounted to the assumed date the final rule would take effect, beginning of year 2007, at two values of the social discount rate, 3% and 7%. These discount rate values reflect guidance from the Office of Management and Budget regulatory analysis guidance document, Circular A-4 (OMB, 2003).[5]

EPA used the following formula to calculate the present value of the time stream of costs as of the beginning of 2007:[6]

$$Present\ Value = \frac{Cost_t}{(1 + r)^{t - 2007}}$$

where:

$Cost_t$	=	Costs in year t
r	=	Social discount rate (3% and 7%)
t	=	Year in which cost is incurred (2007 to 2043)

After calculating the present value (PV) of these cost streams, EPA calculated their constant annual equivalent value (annualized value) using the annualization formula presented below, again using the two values of the social discount rate, 3% and 7%. Although the analysis period extends from 2007 through 2043, a period of 37 years, EPA annualized costs over 30 years, since 30 years is the assumed period of compliance. This same annualization concept and period of annualization were also followed in the analysis of benefits, although for benefits the time horizon of analysis for calculating the present value is longer than for costs. Using a 30-year annualization period for both social costs and benefits allows comparison of constant annual equivalent values of costs and benefits that have been calculated on a mathematically consistent basis. The annualization formula is as follows:

$$Annualized\ Cost = PV\ of\ Cost \times \frac{r \times (1 + r)^{(n-1)}}{(1 + r)^n - 1}$$

where:

r	=	Social discount rate (3% and 7%)
n	=	Annualization period, 30 years for the social cost analysis

B1-2.4 Discounting and Annualization – Costs to Complying Facilities

In general, EPA followed similar concepts and procedures in the discounting and annualization required for the analysis of costs to, and impacts on, complying facilities as those followed for the analysis of social costs. However, the analysis of costs to complying facilities differs from that for costs to society in several important ways, which are described below.

- ***Consideration of taxes.*** For understanding the impact of the regulation on complying facilities, the costs incurred by complying facilities are adjusted for taxes, as relevant, and calculated on an after-tax basis. The tax treatment of compliance outlays and income effects (e.g., from installation downtime) shifts part of these costs to the tax-paying public and reduces the actual cost to private, tax-paying businesses. For this reason, the after-tax costs of compliance are a more meaningful measure of the financial burden on complying facilities than the pre-tax costs. In analyzing and reporting the impact of compliance costs on private facilities, annualized costs are therefore calculated on an after-tax basis.

- ***Use of discount rates in present value and annualization calculations.*** The discount rate used in the facility cost calculations generally has a different interpretation than the rate used for the social cost

[5] See *Chapter E1: Summary of Social Costs*, for further discussion of the framework for analyzing the social costs of the 316(b) Phase III regulation.

[6] Calculation of the present value assumes that the cost is incurred at the beginning of the year.

calculation (even though, in some instances, the numerical value of the rate may be the same). Instead of being a social discount rate, the discount rate used for the present value and annualization calculations for complying facility costs represents a cost of capital to the individual complying facility, which may reasonably differ from the concept of the social discount rate. The social discount rate may be derived on several bases, including: (1) as an opportunity cost of capital *to society* or (2) as a societal inter-temporal preference or indifference rate – i.e., the required rate of change over time in a value of consumption or outlay, at which society would be indifferent to the time period in which the consumption or outlay occurs. The discount rates based on these *society-level* concepts may reasonably differ from the cost of capital used for assessing costs and financial impacts to the complying firm.

- ***Calculation of present value and annualization of costs at the year of compliance.*** In the social cost analysis, costs incurred over 30 years were summed on a present value basis at the beginning of 2007, the assumed date the final regulation would take effect. The present value was then annualized over 30 years. The analysis of costs to complying facilities differs in two respects: (1) Costs were calculated on a present value basis and annualized *at the first year of compliance for each facility*, rather than at the beginning of 2007. The calculation of annualized costs at the first year of compliance provides more accurate and meaningful insight for assessing financial impact in relation to the baseline financial performance and conditions of the complying facility than would be achieved if, for example, costs were further discounted – and reduced numerically – by bringing them to the year the rule would take effect. (2) Each non-annually recurring cost component was only *accounted for once*, rather than repeated at each occurrence over the 30-year period. EPA accounted for the recurring nature of these costs (e.g., technology costs are assumed to recur every 10 years) through the annualization period (see bullet below). The resulting aggregates of annualized cost over facilities, for purposes of reporting total cost to complying facilities and total financial burden, are the sum of costs at the initial year of compliance for each facility, even though those years differ across facilities. EPA used the following formula to calculate the present value of the time stream of costs as of the beginning of each facility's compliance year:[7]

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

  where:

$Cost_{x,t}$	=	Costs incurred by facility x in year t
r	=	Discount rate (7%)
t	=	Year in which cost is incurred (2007 to 2018)[8]
Compliance $Year_x$	=	Estimated compliance year of facility x

- ***Annualization period.*** The present value estimates of the one-time or non-annually recurring costs were then annualized over the relevant period for which the outlay is expected to produce compliance value. The capital outlays for compliance equipment installation were annualized over the expected useful life of the compliance equipment, 10 years. The income loss from installation downtime was annualized over the facility's 30-year compliance period. Although compliance equipment would need to be reinstalled at 10-year intervals during the compliance period, the engineering analysis indicates that reinstallation would not require additional downtime. Thus, the relevant period for annualization of the income loss from installation downtime is the full 30 years of compliance assumed for this analysis. The pre-permit study costs and other initial permitting costs were also annualized over the 30-year compliance period while repermitting costs were annualized over 5 years, the interval at which these costs occur. All annualized cost values, which were developed on a consistent discounting and annualization basis, are

[7] Calculation of the present value assumes that the cost is incurred at the beginning of the year.

[8] The first compliance year is 2010. A facility with a 2010 compliance year and a 3-year study requirement would incur its first costs in 2007. The last compliance year is 2014. A facility with a 2014 compliance year would incur the costs of its last non-annual recurring cost component, repermitting, five years after compliance, in 2018.

then able to be summed with annually recurring costs (e.g., annual operating and maintenance expense) to yield a total annualized cost to complying facilities. The annualization formula is as follows:

$$Annualized\ Cost = PV\ of\ Cost \times \frac{r \times (1 + r)^{(n-1)}}{(1 + r)^{n} - 1}$$

where:

r	=	Discount rate (7%)
n	=	Annualization period (10 years for compliance equipment; 30 years for installation downtime and initial permitting costs; 5 years for repermitting costs)

See Chapters B3 and B5 for additional detail on the present value and annualization concepts and procedures used in the specific analyses by existing facility industry segment.

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Chapter B2: Profile of Manufacturers

CHAPTER CONTENTS

INTRODUCTION

Using information from the *1982 Census of Manufactures* and from effluent guideline development materials, EPA identified four 2-digit SIC code industries, in addition to the electric power industry (SIC Group 49), that would likely be subject to regulation under section 316(b). After the electric power industry, these industries – Paper and Allied Products (SIC 26), Chemicals and Allied Products (SIC 28), Petroleum and Coal Products (SIC 29), and Primary Metal Industries (SIC 33) – are most reliant on cooling water for their operations.

Facilities in other industries also use cooling water and could therefore be subject to section 316(b) regulations; however, based on the *1982 Census of Manufactures* data and engineering-based insight into industrial use of cooling water, the cooling water intake flow of these remaining industries is small relative to that of the power industry and the four selected industries. Therefore, this Profile of Manufacturers focuses on the manufacturing groups listed above. In its review of these industries, EPA divided the Primary Metal Industries (SIC 33) into Steel (SIC 331) and Aluminum (SIC 333/335), based on the business and other operational differences in these two major segments. The resulting five manufacturing industries – (1) Paper and Allied Products, (2) Chemicals and Allied Products, (3) Petroleum and Coal Products, (4) Steel, and (5) Aluminum – comprise the "Primary Manufacturing Industries," as referred to in this profile and elsewhere in this Economic Analysis report.

A key data source for EPA's analysis for the 316(b) Phase III regulation is the detailed questionnaire issued to a sample of facilities identified as potentially subject to the Phase III regulation. Based on responses to a screener survey, EPA targeted the detailed questionnaire to facilities believed to be in the major cooling water-use industries, including the electric power industry, listed above. EPA received a number of responses from facilities with business operations in industries other than the manufacturing industries listed above. EPA originally believed these facilities to be non-utility electric power generators; however, inspection of their responses indicated that the facilities were better understood as cooling water-dependent facilities whose principal operations lie in businesses other than the electric power industry or manufacturing industries listed above. This profile includes information for these facilities, referred to as "Other Industries."

The remainder of this chapter is divided into six sections:

- B2A: Paper and Allied Products (SIC 26),
- B2B: Chemicals and Allied Products (SIC 28),
- B2C: Petroleum and Coal Products (SIC 29),
- B2D: Steel (SIC 331),
- B2E: Aluminum (SIC 333/335), and
- B2F: Other Industries.

Each industry section except for Other Industries is divided into the following five subsections: (1) summary insights from this profile, (2) domestic production, (3) structure and competitiveness, (4) financial condition and performance, and (5) facilities potentially subject to the Phase III regulation. The Other Industries section contains only summary information for those facilities for which questionnaire responses were received; this section does not include the industry specific discussions since the "Other Industry" facilities are in a variety of different industries, which, as noted above, rely to a much less substantial degree on cooling water to support their operations.

This profile uses the Standard Industrial Classification (SIC) system as the primary framework for analyzing and reporting information about the industries analyzed for the section 316(b) Phase III regulation. However, the more recent data were often reported in the North American Industry Classification System (NAICS), which the U.S. Census Bureau adopted in 1997 for economic reporting. Where necessary, EPA converted information reported in the NAICS framework to the SIC framework using the 1997 Economic Census *Bridge Between NAICS and SIC*. In most instances, these translations are straightforward; however, for some segments, the translation may introduce inconsistencies in data series at the point of changeover from the SIC to the NAICS frameworks.

Chapter B2A: Paper and Allied Products (SIC 26)

EPA's *Detailed Industry Questionnaire*, hereafter referred to as DQ, identified five 4-digit SIC codes in the Paper and Allied Products industry (SIC 26) with at least one existing facility that operates a CWIS, holds a NPDES permit, and withdraws equal to or greater than two million gallons per day (MGD) from a water of the United States, and uses at least 25 percent of its intake flow for cooling purposes. (facilities with these characteristics are hereafter referred to as facilities potentially subject to the Phase III regulation or "potential Phase III facilities").

For each of the five SIC codes, Table B2A-1 below provides a description of the industry segment, a list of primary products manufactured, the total number of detailed questionnaire respondents (weighted to represent national results), and the number and percent of potential Phase III facilities within the estimated national total of facilities in the respective industry SIC code groups.

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Table B2A-1: Potential Phase III facilities in the Paper and Allied Products Industry (SIC 26)

SIC	SIC Description	Important Products Manufactured	Number of Facilities[a] Total	Potential Phase III facilities [b]	%
2611	Pulp Mills	Pulp from wood or from other materials, such as rags, linters, wastepaper, and straw; integrated logging and pulp mill operations if primarily shipping pulp.	60	41	68.3%
2621	Paper Mills	Paper from wood pulp and other fiber pulp, converted paper products; integrated operations of producing pulp and manufacturing paper if primarily shipping paper or paper products.	290	133	45.9%
2631	Paperboard Mills	Paperboard, including paperboard coated on the paperboard machine, from wood pulp and other fiber pulp; and converted paperboard products; integrated operations of producing pulp and manufacturing paperboard if primarily shipping paperboard or paperboard products.	190	52	27.4%
		Total	***540***	***225***	***41.7%***

Table B2A-1: Potential Phase III facilities in the Paper and Allied Products Industry (SIC 26)

SIC	SIC Description	Important Products Manufactured	Number of Facilities[a]		
			Total	Potential Phase III facilities [b]	%
		Other Paper and Allied Products Segments			
2676	Sanitary Paper Products	Sanitary paper products from purchased paper, such as facial tissues and handkerchiefs, table napkins, toilet paper, towels, disposable diapers, and sanitary napkins and tampons.	4	2	50.0%
2679	Converted Paper and Paperboard Products, Not Elsewhere Classified	Laminated building paper, cigarette paper, confetti, pressed and molded pulp cups and dishes, paper doilies, egg cartons, egg case filler flats, papier-mache, filter paper, foil board, gift wrap paper, wallpaper, etc.	19	3	15.8%
		Total Other	***23***	***5***	***50.0%***
		Total Paper and Allied Products (SIC 26)			
		Total SIC Code 26	***563***	***230***	***40.9%***

[a] Number of weighted detailed questionnaire survey respondents.
[b] Individual numbers may not add up due to independent rounding.

Source: U.S. EPA, 2000; Executive Office of the President, 1987.

The table shows that an estimated 230 out of 563 facilities (or 41 percent) in the Paper and Allied Products Industry (SIC 26) are potentially subject to the proposed regulation. EPA also estimated the percentage of total production that occurs at facilities potentially subject to the proposed regulation. Total value of shipments for the paper and allied products industry from the 1998 Annual Survey of Manufacturers is $84.9 billion. Value of shipments, a measure of the dollar value of production, was selected for the basis of this estimate. Because the DQ did not collect value of shipments data, these data were not available for the sample of Phase III manufacturing facilities potentially subject to the proposed regulation. Total revenue, as reported on the DQ, was used as a close approximation for value of shipments for these facilities. EPA estimated the total revenue of facilities in the paper industry potentially subject to the proposed regulation is $55.1 billion. Therefore, EPA estimates that 65 percent of total production in the paper industry occurs at facilities potentially subject to the proposed regulation.

The responses to the Detailed Industry Questionnaire indicate that three segments account for most of the potential Phase III facilities in the Paper and Allied Products industry: (1) Pulp Mills (SIC 2611), (2) Paper Mills (SIC 2621), and (3) Paperboard Mills (SIC 2631). Of the 239 potential Phase III facilities in the paper and allied products industry, 59 percent are Paper Mills. Paperboard Mills and Pulp Mills account for 22 and 18 percent of facilities, respectively. The remainder of this profile therefore focuses on these three industry segments.

Table B2A-2 provides the cross-walk between SIC codes and NAICS codes for the profiled paper SIC codes. The table shows that both Pulp Mills and Paperboard Mills have a one-to-one relationship to their NAICS codes. Paper Mills correspond to two NAICS codes (322121 and 322122). NAICS 322121, classified as Paper (except newsprint) Mills, represents a large portion of SIC code 2621 (84 percent based on value of shipments).

Table B2A-2: Relationship between SIC and NAICS Codes for the Paper and Allied Products Industry (1997)

SIC Code	SIC Description	NAICS Code	NAICS Description	Establishments	Value of Shipments ($000)	Employment
2611	Pulp mills	322110	Pulp mills	39	4,072,965	10,247
2621	Paper mills	322121	Paper (except newsprint) mills (pt)	225	29,930,133	93,537
		322122	Newsprint mills	31	5,584,285	14,015
2631	Paperboard mills	322130	Paperboard mills	217	19,828,695	54,643

Source: U.S. DOC, 1997.

B2A-1 SUMMARY INSIGHTS FROM THIS PROFILE

A key purpose of this profile is to provide insight into the ability of pulp and paper firms that would potentially be subject to the proposed Phase III regulation to absorb compliance costs without material adverse economic/financial effects. Two important factors in the ability of the industry's ability to withstand compliance costs are: (1) the extent to which the industry may be expected to shift compliance costs to its customers through price increases and (2) the financial health of the industry and its general business outlook.

Likely Ability to Pass Compliance Costs Through to Customers
As reported in the following sections of this profile, the pulp and paper industry is relatively unconcentrated, which would suggest that firms in this industry may face difficulty in passing through to customers a significant portion of their compliance-related costs. The domestic *pulp* industry also faces significant competitive pressures from abroad, further curtailing the potential of firms in this industry to pass through to customers a significant portion of their compliance-related costs. The domestic *Paper Mills* and *Paperboard Mills* segments do not face as significant foreign competitive pressures, and, based on this factor, would have more latitude in passing through to customers any increase in production costs resulting from regulatory compliance. However, foreign pressure is likely to increase as capacity in foreign countries, particularly China, continues to grow and exert pressure on the domestic market. As discussed above, the proportion of total value of shipments in the industry potentially subject to the proposed regulation is 65 percent. The actual proportion of total value of shipments subject to regulation-induced compliance costs would be smaller since not all of the potentially regulated facilities would be subject to the national categorical requirements of the proposed regulation: that is, facilities below the proposed design intake flow (DIF) would be subject to permitting based on best professional judgement (BPJ) rather than based on national standards, and several facilities currently employ baseline technologies that meet the requirements of the proposed regulation. Given the likelihood that these percentages represent upper bound estimates, EPA believes that the theoretical threshold for justifying the use of industry-wide CPT rates in the impact analysis of existing Phase III pulp and paper facilities has not been met. For these reasons, in its analysis of regulatory impacts for the pulp and paper industry, EPA assumed that complying firms would be unable to pass compliance costs through to customers: i.e., complying facilities must absorb all compliance costs within their financial condition at the time of compliance (see following sections and Appendix 3 to *Chapter B3: Economic Impact Analysis for Manufacturers* for further information).

Financial Health and General Business Outlook
Over the past decade, the pulp and paper industry, like other U.S. manufacturing industries, has experienced a range of economic/financial conditions, including substantial challenges. In the early 1990s, general economic weakness diminished financial performance in the domestic pulp and paper industry. Domestic market conditions were erratic in the 1990s, with financial performance peaking mid-decade, before declining again as overproduction caused a glut of product and decreasing prices. Going into 2000, the industry's financial

performance had started to improve, but the subsequent recession and global economic downturn, coupled with continuing overproduction led to declining financial results through 2003. Going forward, the industry continues to face increased foreign competition, global and domestic overcapacity, and a failure to adapt to changing business conditions (McNutt, Cenatempo & Kinstrey, 2004). At the same time, with the ongoing improvement in U.S. economic conditions, the pulp and paper industry appears poised to achieve stronger financial performance in 2004 and later years. This should position firms to better withstand additional regulatory compliance costs without imposing significant financial impacts.

B2A-2 DOMESTIC PRODUCTION

The paper and allied products industry is one of the top ten U.S. manufacturing industries, and among the top five segments in sales of nondurable goods. Growth in the paper industry is closely tied to overall gross domestic product (GDP) growth. Although the domestic market consumes over 90 percent of total U.S. paper and allied products industry output, exports have taken on an increasingly important role, and growth in a number of key foreign paper and paperboard markets are a key factor in the health and expansion of the U.S. industry (McGraw-Hill, 2000). The industry is considered mature, with growth slower than that of the GDP, and U.S. producers have actively sought growth opportunities in overseas markets. Although exports still represent a small share of domestic shipments, they exert an important marginal influence on capacity utilization. Prices and industry profits, which are sensitive to capacity utilization, have therefore become increasingly sensitive to trends in global markets. The industry experienced relatively stable production and sales during the 1990s, but saw more volatile capacity utilization, profitability, and prices (Ince, 1999).

With the slowing of the U.S. economy in 2000, and the onset of recession in 2001, the resulting drop in demand and prices put pressure on companies in the industry to eliminate excess capacity. Through aggressive consolidation and streamlining of their operations, facilities sought to lower expenses through elimination of older and less cost efficient operations. In 2002, paper companies eliminated three million tons of capacity, with similar reductions expected in 2003. (Value Line, 2003).

The U.S. Paper and Allied Products industry has a world-wide reputation as a high quality, high volume, and low-cost producer. The industry benefits from many key operating advantages, including a large domestic market; the world's highest per capita consumption; a modern manufacturing infrastructure; adequate raw material, water, and energy resources; a highly skilled labor force; and an efficient transportation and distribution network (Stanley, 2000). U.S. producers face growing competition from new facilities constructed overseas, however (McGraw-Hill, 2000).

The industry is a major energy user, second only to the chemicals and metals industries. However, 56 percent of total energy used in 1998-99 was self-generated (McGraw-Hill, 2000). The use of renewable resources (biomass, black liquor, hydroelectric, etc.) for energy production has increased from 40 percent of total industry energy consumption in 1972 to 56 percent in 2000, and is currently estimated to account for about 60 percent of consumption in 2004 (Paper Age, 2004a).

B2A-2.1 Output

The paper and allied products industry has experienced continued globalization and cyclical pattens in production and earnings over the last two decades. Capital investments in the 1980s resulted in significant overcapacity. U.S. producers experienced record sales in 1995. In 1996, lower domestic and foreign demand, coupled with declining prices, caused the industry's total shipments to decline by 2.2 percent. More recently, three consecutive years of increasing demand and slowly increasing prices led to better industry performance at the end of the 1990s. During these years, domestic producers controlled operating rates to allow drawdown of high inventories and to achieve higher capacity utilization. U.S. producers have also placed a greater emphasis on foreign markets, both through export sales and investments in overseas facilities (McGraw-Hill, 2000). The paper products industry recorded improved sales and stronger earnings in 1999 and early 2000, but began to experience declines in sales in the second half of 2000, reflecting reduced paper and packaging demand due to the slowdown in the U.S. economy and a growth in imports (S&P, 2001). Most products were characterized by weak demand, reduced production and price reductions in 2001, due to continuing reductions in domestic demand (Paperloop, 2001). Annual sales in the U.S. in 2001 dropped 1.5%, while earnings at the top 31 U.S. corporations fell by nearly 75%, partly due to a decrease in prices of up to 15% (Paun et al. 2004).

Capacity for U.S. paper and paperboard declined annually from 2001 to 2003, in contrast to annual increases in capacity for the previous two decades. Capacity declined 1.9% in 2001, 1.3% in 2002, and 0.4% in 2003, and is expected to remain unchanged from 2004 to 2006 due to increased foreign competition, mature domestic markets, and competition from other media (Paper Age, 2004b). Overcapacity has been a problem within the industry. As the world economy began to slow in the early 2000s, demand in the U.S. and abroad waned, forcing producers to limit production to prevent oversupply and keep pricing levels from dropping further (S&P, 2004b). In addition to production downtime, many older, less efficient, single mill operations were permanently closed. In 2001, pulp production decreased 7.3% to 53 million tons, while paper and paperboard production decreased 5.5% to 81 million tons (Paun et al. 2004).

For 2004, paper industry demand and prices are expected to remain at 2003 levels or increase slightly. As the economy continues to improve, demand should start to pick up, with better financial performance expected in 2005, as long as the industry continues careful management of production levels and control of inventories . In addition, the weakened dollar should help to improve performance in export markets (S&P, 2004a). These improving conditions should better position firms to manage any increase in production costs resulting from regulatory compliance.

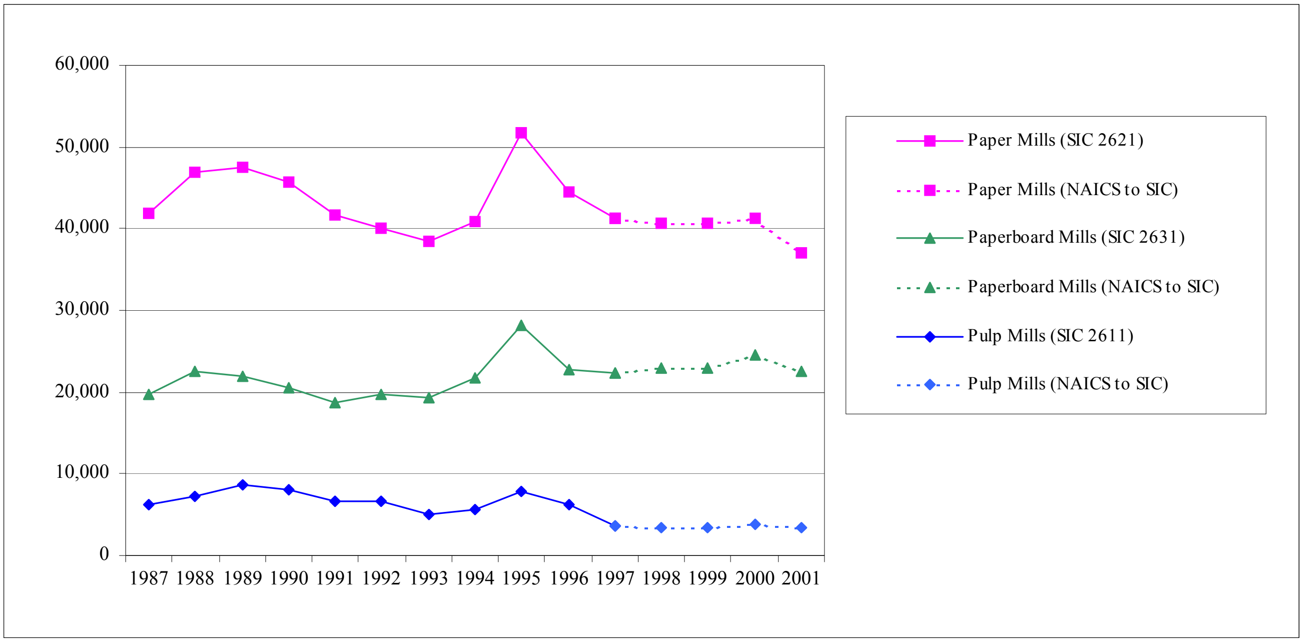
Figure B2A-1 shows the trend in constant ***value of shipments*** and ***value added*** for the three profiled segments.[1] Value of shipments and value added are two common measures of manufacturing output. They provide insight into the overall economic health and outlook for an industry. Value of shipments is the sum of the receipts a manufacturer earns from the sale of its outputs; it indicates the overall size of a market or the size of a firm in relation to its market or competitors. Value added measures the value of production activity in a particular industry. It is the difference between the value of shipments and the value of inputs used to make the products sold.

The trends over time in value of shipments and value added show that the Paper and Allied Products has performed erratically over the 1987-2001 period, with swings in shipments and value added generally following the performance trend of the aggregate U.S. economy. Of the three profiled industry segments, only Paperboard Mills reached the end of the analysis period with a higher total value of shipments and value added than in 1987; both Paper Mills and Pulp Mills recorded real declines in shipments and value added over the 15 year period.

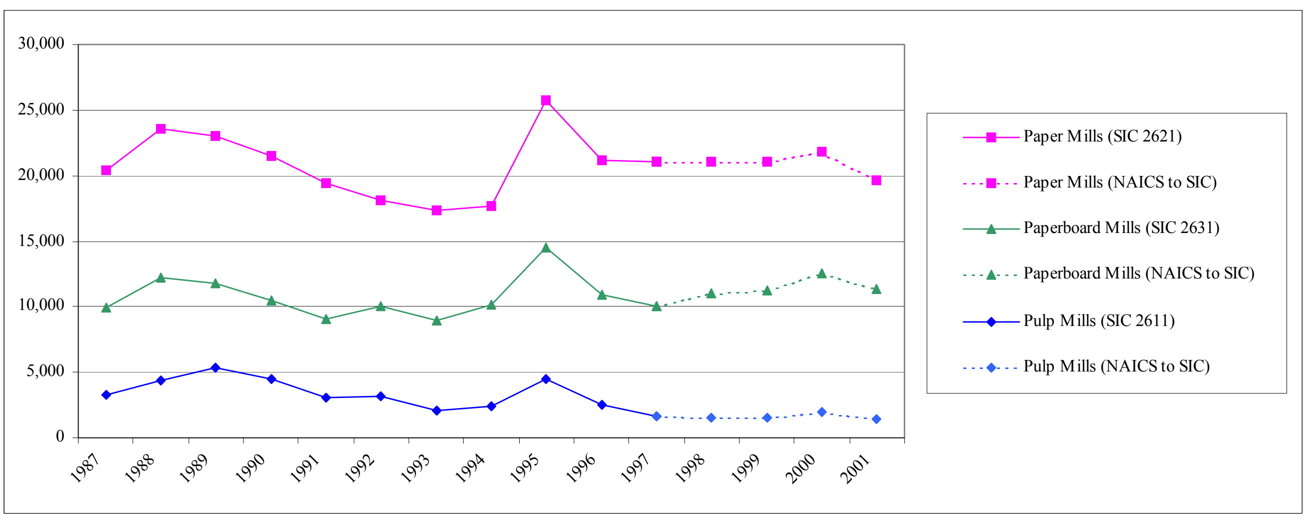
[1]Terms highlighted in bold and italic font are further explained in the glossary.

Figure B2A-1: Value of Shipments and Value Added for Profiled Paper and Allied Products Segments (millions,$2003)

Value of Shipments



Value Added



[a] Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

Source: U.S. DOC, 1988-1991, 1993-1996, and 1998-2001; U.S. DOC, 1987, 1992, and 1997.

Table B2A-3 provides the Federal Reserve System's index of industrial production for the profiled pulp and paper segments, which shows trends in production between 1989 and 2003. This index more closely reflects total output in physical terms, whereas value of shipments and value added reflect the economic value of production. The production index is expressed as a percentage of output in the base year, 1997. Production peaked in 1995 for all three segments, which was the best year of financial performance for the industry (see Table B2A-8). The subsequent oversupply led to cuts in production and weaker financial performance. Financial results improved at the end of the 1990s and into 2000, as paper and paperboard firms limited production in an effort to reduce excess inventory. The global economic downturn and weakened demand that began in the latter half of 2000 forced further reductions in production in subsequent years. In contrast to the Paper Mills and Paperboard Mills segments, Pulp Mills have gradually increased production after the initial fall from the 1995 production peak.

Table B2A-3: U.S. Pulp and Paper Industry Industrial Production Index

Year	Pulp Mills[a]		Paper Mills[b]		Paperboard Mills[c]	
	Index 1997=100	Percent Change	Index 1997=100	Percent Change	Index 1997=100	Percent Change
1989	107.4	n/a	105.7	n/a	88.0	n/a
1990	107.3	-0.1%	103.5	-2.1%	88.4	0.4%
1991	109.0	1.6%	100.2	-3.3%	87.6	-1.0%
1992	114.6	5.2%	99.0	-1.2%	91.5	4.4%
1993	96.3	-16.0%	98.3	-0.6%	93.4	2.1%
1994	102.0	5.9%	103.9	5.6%	98.8	5.8%
1995	109.6	7.5%	107.4	3.4%	102.4	3.7%
1996	100.5	-8.3%	101.1	-5.9%	97.6	-4.7%
1997	100.1	-0.4%	100.0	-1.1%	100.1	2.5%
1998	101.2	1.1%	99.7	-0.3%	100.1	0.1%
1999	101.7	0.5%	104.0	4.4%	101.4	1.2%
2000	103.8	2.1%	101.5	-2.5%	96.8	-4.5%
2001	102.1	-1.7%	94.0	-7.4%	93.4	-3.5%
2002	103.1	0.9%	91.9	-2.2%	94.7	1.4%
2003	103.5	0.5%	90.4	-1.6%	94.6	-0.1%
Total Percent Change 1989-2000	**-3.6%**		**-14.5%**		**7.5%**	
Average Annual Growth Rate	**-0.3%**		**-1.1%**		**0.5%**	

[a] Includes NAICS 32211.
[b] Includes NAICS 32212.
[c] Includes NAICS 32213.

Source: Federal Reserve Board, 2004.

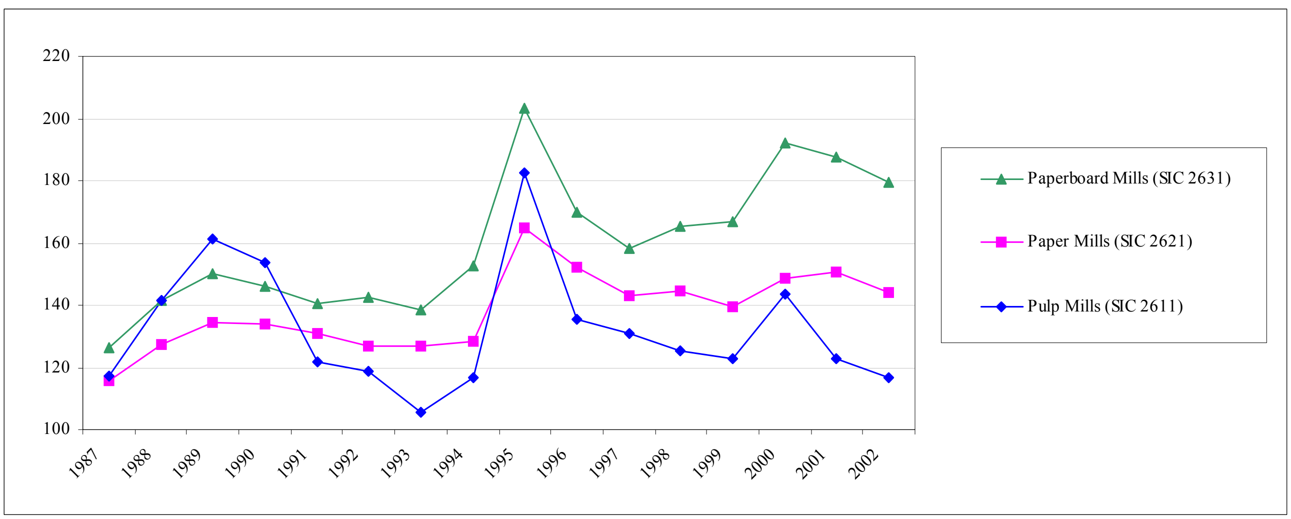
B2A-2.2 Prices

The ***producer price index*** (PPI) measures price changes, by segment, from the perspective of the seller, and indicates the overall trend of product pricing, and thus supply-demand conditions, within a segment.

Figure B2A-2 shows that price levels in the U.S. paper industry closely reflect domestic and foreign demand, and industry capacity and operating rates, which determine supply (S&P, 2001). Prices tend to be volatile due to mismatches between short-term supply and demand. The industry is very capital intensive, and development of new capacity requires several years. Prices therefore tend to increase when demand and capacity utilization rise, and drop sharply when demand softens or when new capacity comes on line. In the past, producers have been reluctant to cut production when demand declines because fixed capital costs are a substantial portion of total manufacturing costs; this reluctance has occasionally caused persistent oversupply. During the recent economic slowdown, however, producers appeared more willing to cut output to prevent sharp reductions in prices (Ince, 1999; S&P, 2001).

The paper industry suffered from low prices throughout the early 1990s. The depressed prices resulted from the paper boom of the late 1980s. Prices recovered in the mid 1990s before declining again in the latter part of the decade. Entering 2000, prices in the paper industry reversed course and rose, before experiencing declines in 2001 and 2002, as prices for most paper grades dropped between 5 and 15 percent (Value Line, 2003). Faced with substantial declines in demand during those years, producers cut production, endured downtime, and closed less efficient facilities to prevent major price declines for paper products (S&P, 2001). Prices started to level near the end of 2002, and entering 2003 producers started to raise prices. With demand uneven, however, the increased pricing did not hold, and at the start of 2004, most of the price increases have vanished (S&P, 2004a).

Figure B2A-2: Producer Price Indexes for Profiled Paper and Allied Products Segments



Source: *BLS, 2002.*

B2A-2.3 Number of facilities and firms

The Statistics of U.S. Businesses reports that the number of facilities and firms in the Pulp Mills segment decreased by 11 percent between 1989 and 2001. One of the reasons for this decline has been the increase in the number of mills that produce deinked recycled market pulp and thus displace demand for virgin pulp mill product. These are secondary fiber processing plants that use recovered paper and paperboard as their sole source of raw material. Producers of deinked market pulp have experienced strong demand over the past several years in both

U.S. and foreign markets. As a result, U.S. deinked recycled market pulp capacity more than doubled between 1994 and 1998 (McGraw-Hill, 2000). Since 1994, the secondary fiber share of total papermaking fiber production has increased steadily, reaching 37 percent in 1999 (McGraw-Hill, 2000).

In contrast, the number of facilities and firms in the Paper Mills and Paperboard Mills segments declined. Overcapacity in the 1990s limited the construction of new facilities. In 1998 and 1999, 577,000 and 2.5 million tons of paper and paperboard capacity were removed from the capacity base. Over the same period, more than one million tons of pulp capacity were removed (Pponline, 1999). In 2001and 2002, 8.2 million tons of capacity closed, mostly in containerboard, market pulp, and print and writing papers. (Paper Age, 2004c).

Tables B2A-4 and B2A-5 present the number of facilities and firms for the three profiled paper and allied products segments between 1989 and 2001.

Table B2A-4: Number of Facilities Owned by Firms in the Profiled Paper and Allied Products Segments

Year	Pulp Mills		Paper Mills		Paperboard Mills	
	Number of Facilities	Percent Change	Number of Facilities	Percent Change	Number of Facilities	Percent Change
1989	46	n/a	322	n/a	221	n/a
1990	46	0.0%	327	1.6%	226	2.3%
1991	53	15.2%	349	6.7%	228	0.9%
1992	44	-17.0%	324	-7.2%	222	-2.6%
1993	46	4.5%	306	-5.6%	217	-2.3%
1994	52	13.0%	316	3.3%	218	0.5%
1995	53	1.9%	317	0.3%	219	0.5%
1996	62	17.0%	344	8.5%	228	4.1%
1997	41	-33.9%	259	-24.7%	214	-6.1%
1998[a]	44	7.3%	235	-9.3%	232	8.4%
1999[a]	45	2.3%	242	3.0%	233	0.4%
2000[a]	48	6.7%	230	-5.0%	238	2.1%
2001[a]	51	6.3%	238	3.5%	237	-0.4%
Total Percent Change 1989-2001	***10.9%***		***-26.1%***		***7.2%***	
Average Annual Growth Rate	***0.9%***		***-2.5%***		***0.6%***	

[a] Before 1998, data were compiled in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

Source: U.S. SBA, 1989-2001.

Table B2A-5: Number of Firms in the Profiled Paper and Allied Products Segments

Year	Pulp Mills		Paper Mills		Paperboard Mills	
	Number of Firms	Percent Change	Number of Firms	Percent Change	Number of Firms	Percent Change
1990	31	n/a	158	n/a	102	n/a
1991	37	19.4%	186	17.7%	102	0.0%
1992	29	-21.6%	161	-13.4%	95	-6.9%
1993	32	10.3%	153	-5.0%	99	4.2%
1994	37	15.6%	163	6.5%	96	-3.0%
1995	32	-13.5%	163	0.0%	93	-3.1%
1996	43	34.4%	186	14.1%	101	8.6%
1997	27	-37.2%	131	-29.6%	85	-15.8%
1998[a]	32	18.5%	124	-5.3%	95	11.8%
1999[a]	33	3.1%	133	7.2%	95	0.0%
2000[a]	36	9.1%	134	0.7%	105	10.5%
2001[a]	40	11.1%	140	4.6%	116	10.5%
Total Percent Change 1990-2001[a]	***3.2%***		***-21.5%***		***-6.9%***	
Average Annual Growth Rate	***0.4%***		***-3.0%***		***-0.9%***	

[a] Before 1998, data were compiled in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

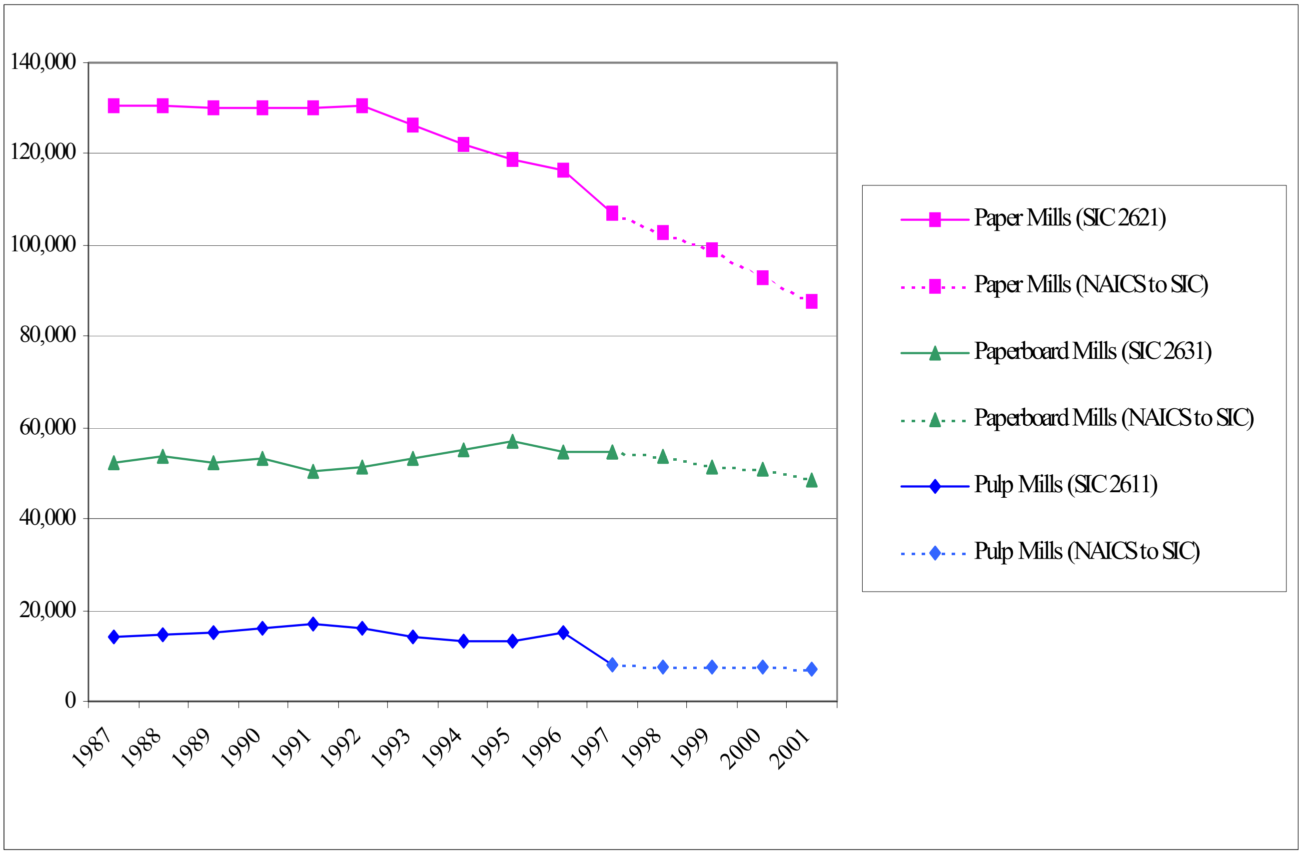
Source: U.S. SBA, 1989-2001.

B2A-2.4 Employment and productivity

The U.S. paper industry is among the most modern in the world. It has a highly skilled labor force and is characterized by large capital expenditures, which have been largely aimed at productivity improvements.

Employment in the three profiled paper industry segments remained relatively constant from 1987 through the mid 1990s. Since then, employment at Pulp Mills has dropped considerably, decreasing by 49 percent; Paper Mills have also seen a substantial reduction in the workforce of close to 33%. Employment in Paperboard Mills fell the least over this period, but has still declined by almost 7 percent. Part of this employment loss is attributable to firms closing older and higher cost facilities (McNutt, Cenatempo & Kinstrey, 2004). Figure B2A-3 presents employment for the three profiled paper segments between 1987 and 2001.

Figure B2A-3: Employment for Profiled Paper and Allied Products Segments



[a] Before 1998, data were compiled in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC.*

Source: U.S. DOC, 1988-1991, 1993-1996, and 1998-2001; U.S. DOC, 1987, 1992, and 1997.

Table B2A-6 on the following page presents the change in value added per labor hour, a measure of ***labor productivity***, for each of the profiled industry segments between 1987 and 2001. The table shows that labor productivity in the Pulp Mills segment has been relatively volatile, posting several double-digit gains and losses between 1987 and 2001. These changes were primarily driven by fluctuations in value added and production levels. Overall, productivity in Pulp Mills decreased by 12% percent during this period, while increasing in Paper Mills and Paperboard Mills by 41 percent and 21 percent, respectively.

Table B2A-6: Productivity Trends for Profiled Paper and Allied Products Segments ($2003)

Year	Pulp Mills				Paper Mills				Paperboard Mills			
	Value Added ($ mill.)	Prod. Hrs. (mill.)	Value Added/Hour ($/hr)	Value Added/Hour Percent Change	Value Added ($ mill.)	Prod. Hrs. (mill.)	Value Added/Hour ($/hr)	Value Added/Hour Percent Change	Value Added ($ mill.)	Prod. Hrs. (mill.)	Value Added/Hour ($/hr)	Value Added/Hour Percent Change
1987	3,293	24	138	n/a	20,349	213	96	n/a	9,980	89	113	n/a
1988	4,350	24	182	31.9%	23,541	215	109	13.5%	12,253	91	135	19.5%
1989	5,297	25	209	14.8%	22,999	214	107	-1.8%	11,833	89	133	-1.5%
1990	4,424	28	160	-23.4%	21,495	211	102	-4.7%	10,519	91	116	-12.8%
1991	3,061	28	111	-30.6%	19,406	212	91	-10.8%	9,080	87	105	-9.5%
1992	3,124	26	119	7.2%	18,159	215	84	-7.7%	10,023	88	113	7.6%
1993	2,045	23	89	-25.2%	17,348	212	82	-2.4%	8,996	90	100	-11.5%
1994	2,450	22	112	25.8%	17,649	206	86	4.9%	10,161	94	108	8.0%
1995	4,493	23	199	77.7%	25,772	201	128	48.8%	14,517	98	149	38.0%
1996	2,478	24	104	-47.7%	21,218	197	108	-15.6%	10,868	95	115	-22.8%
1997	1,669	13	129	24.0%	21,077	182	116	7.4%	10,011	93	108	-6.1%
1998[a]	1,538	12	124	-3.9%	21,065	173	122	5.2%	11,072	90	123	13.9%
1999[a]	1,558	12	133	7.3%	21,099	167	126	3.3%	11,259	86	131	6.5%
2000[a]	1,930	12	162	21.8%	21,864	155	141	11.9%	12,587	86	146	11.5%
2001[a]	1,459	12	122	-24.7%	19,660	145	135	-4.3%	11,383	83	137	-6.2%
Total Percent Change 1987-2001	***-55.7%***	***-50.0%***	***-11.6 %***		***-3.4%***	***-31.9%***	***40.6%***		***14.1%***	***-6.7%***	***21.2%***	
Average Annual Growth Rate	***-5.6%***	***-4.8%***	***-0.9%***		***-0.2%***	***-2.7%***	***2.5%***		***0.9%***	***-0.5%***	***1.4%***	

[a] Before 1998, data were compiled in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

Source: U.S. DOC, 1988-1991, 1993-1996, and 1998-2001; U.S. DOC, 1987, 1992, and 1997.

B2A-2.5 Capital expenditures

The paper and allied products industry is a highly capital intensive industry. Capital-intensive industries are characterized by a large value of capital equipment per dollar value of production. ***New capital expenditures*** are needed to modernize, expand, and replace existing capacity. Consistently high levels of capital expenditures have made the U.S. paper industry one of the most modern industries in the world (Stanley, 2000). The total level of capital expenditures for the pulp, paper, and paperboard industries was $3.8 billion in 2001 (in $2003). The Paper Mills and Paperboard Mills segments accounted for approximately 95 percent of that spending (see Table B2A-7). Most of the spending is for production improvements (through existing machine upgrades, retrofits, or new installed equipment), environmental concerns, and increased recycling (McGraw Hill, 2000). The total capital expenditure for 2001 is considerably less, in real terms, than what was spent in the early 1990s, as producers became wary of adding too much capacity that might lead to oversupply and depressed prices.

The Department of Commerce estimates that environmental spending accounted for about 14 percent of all capital outlays made by the U.S. paper industry since the 1980s, and the Cluster Rule promulgated in 1998 is expected to require increased environmental expenditures (S&P, 2001).

Table B2A-7: Capital Expenditures for Profiled Paper and Allied Products Segments (millions, $2003)

Year	Pulp Mills		Paper Mills		Paperboard Mills	
	Capital Expenditures	Percent Change	Capital Expenditures	Percent Change	Capital Expenditures	Percent Change
1987	333	n/a	3,993	n/a	1,115	n/a
1988	432	29.3%	4,605	15.3%	2,118	89.9%
1989	937	117.1%	7,043	52.9%	2,224	5.0%
1990	1,364	45.6%	5,539	-21.4%	3,854	73.3%
1991	1,240	-9.1%	4,551	-17.8%	2,693	-30.1%
1992	945	-23.8%	3,561	-21.8%	2,496	-7.3%
1993	509	-46.1%	3,423	-3.9%	1,964	-21.3%
1994	369	-27.5%	3,761	9.9%	2,044	4.1%
1995	530	43.6%	3,149	-16.3%	2,400	17.4%
1996	786	48.3%	3,538	12.3%	2,656	10.7%
1997	382	-51.4%	3,211	-9.2%	1,788	-32.7%
1998[a]	455	19.3%	3,422	6.6%	1,526	-14.6%
1999[a]	201	-55.8%	2,539	-25.8%	1,374	-10.0%
2000[a]	250	24.2%	2,712	6.8%	1,253	-8.8%
2001[a]	199	-20.3%	2,547	-6.1%	1,063	-15.2%
Total Percent Change 1987- 2001[a]	***-40.2%***		***-36.2%***		***-4.7%***	
Average Annual Growth Rate	***-3.6%***		***-3.2%***		***-0.3%***	

[a] Before 1998, data were compiled in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

Source: U.S. DOC, 1988-1991, 1993-1996, and 1998-2001; U.S. DOC, 1987, 1992, and 1997.

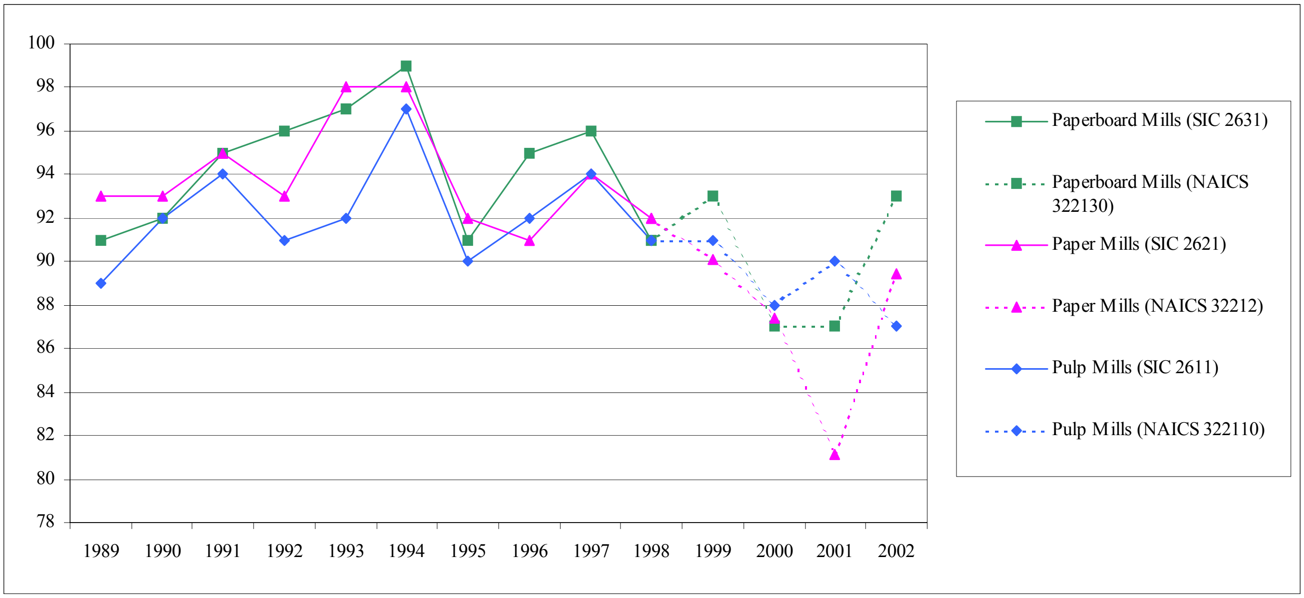
B2A-2.6 Capacity utilization

Capacity utilization measures actual output as a percentage of total potential output given the available capacity. Capacity utilization provides insight into the extent of excess or insufficient capacity in an industry, and into the likelihood of investment in new capacity. According to the U.S. Industry and Trade Outlook, a utilization rate in the range of 92 to 96 percent is necessary for the Pulp Mills segment to remain productive and profitable (McGraw-Hill, 2000).

As shown in Figure B2A-4, capacity utilization fluctuated sharply in all three profiled segments over the analysis period. Capacity utilization increased between 1989 and 1994, and then fell sharply in 1995. This sharp drop resulted from an effort to reduce inventories, which had begun rising in 1995 in response to low demand and oversupply (McGraw-Hill, 2000). As inventories were sold off and global economic activity strengthened, capacity utilization began to rise again in 1996, peaked in 1997, and again declined in 1998 due to reduced demand from the Asian market (S&P, 2001). With the global economic slowdown starting in 2000, paper producers were forced to implement production cutbacks and downtime to prevent oversupply from further depressing prices. As a result, utilization rates fell farther in 2000 and 2001 to values below those observed in the prior decade. At the same time, overall capacity contracted as companies permanently closed less efficient facilities. The industry is expected to continue consolidating, which should aid profitability in the long run (S&P, 2004b).

Figure B2A-4 presents the capacity utilization indexes from 1989 to 2002 for the three profiled segments.

Figure B2A-4: Capacity Utilization Rate (Fourth Quarter) for Pulp and Paper Industry



[a] Before 1998, data were compiled in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC.*

Source: *U.S. DOC, 1989-2002.*

B2A-3 Structure and Competitiveness

Paper and allied products companies range in size from large corporations having billions of dollars of sales, to small producers with revenue a fraction of the size of the large producers. Because all paper and allied products companies use the same base materials in their production, most manufacture more than one product. To escape the extreme price volatility of commodity markets, many smaller manufacturers have differentiated their products by offering value-added grades. The smaller markets for value-added products make this avenue less available to the larger firms (S&P, 2001).

The paper industry has consolidated through mergers and acquisitions and has closed older mills over the last few years, as a way to improve profits in a mature industry. About six percent of North American containerboard capacity was shut down (most on a permanent basis) in late 1998 and early 1999. Companies have been reluctant to invest in any major new capacity, which might result in excess capacity (S&P, 2001). In 1999, new capacity additions in the paper and allied products industry were at their lowest level of the past ten years; this caution in adding to capacity is expected to continue (Pponline.com, 2000). Another problem for the industry is the increasing capacity being brought online in foreign countries, which could result in higher U.S. import levels and increased competition for U.S. products in export markets (S&P, 2004a).

Major recent mergers include International Paper's acquisition of Champion International in 2000 and Union Camp in 1999, Georgia-Pacific's takeover of Fort James Corp. (itself a 1997 combination of James River and Fort Howard), Weyerhaeuser's acquisition of Willamette Industries Inc., the merger of Mead and Westvaco, and Temple-Inland's takeover of Gaylord Container. (S&P, 2001, 2004b).

B2A-3.1 Geographic distribution

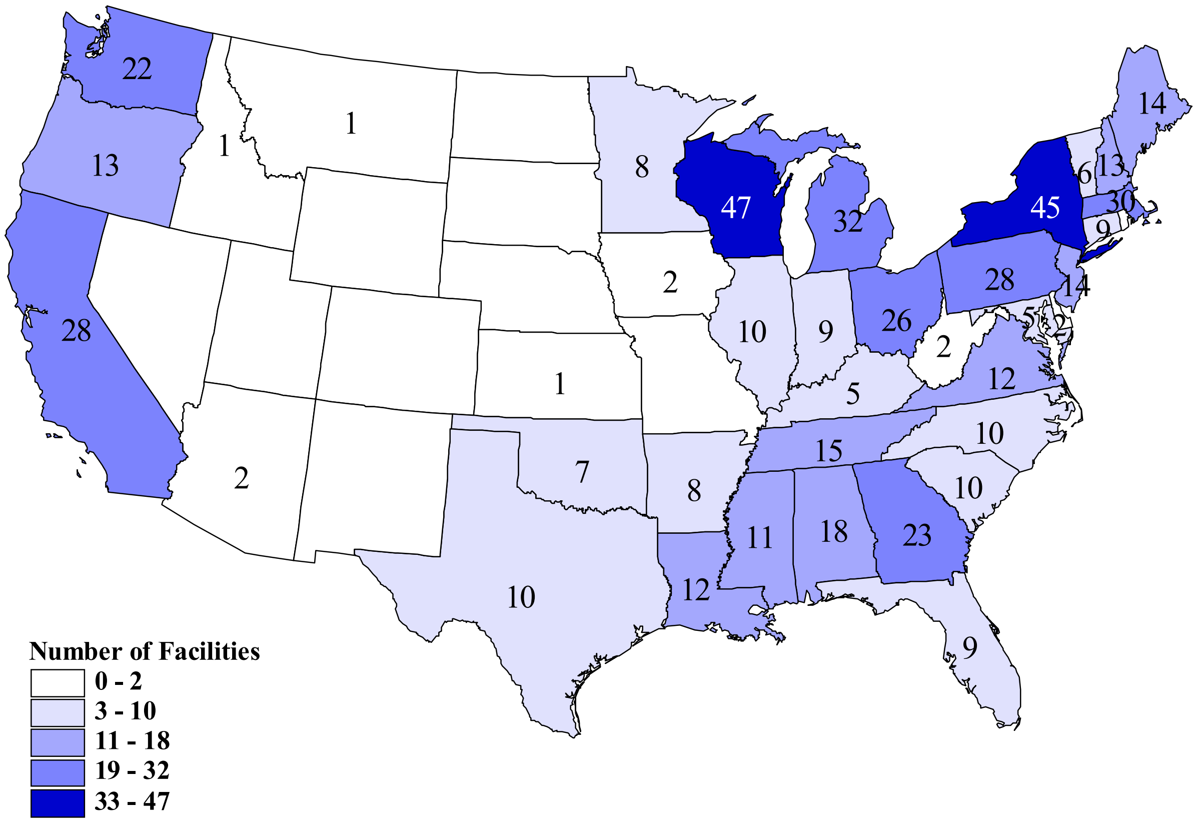
The geographic distribution of pulp, paper, and paperboard mills varies with the different types of mills. Traditional Pulp Mills tend to be located in regions where pulp trees are harvested from natural stands or tree farms. The Southeast (GA, AL, NC, TN, FL, MS, KY), Northwest (WA, CA, AK), Northeast (ME) and Northern Central (WI, MI) regions account for the major concentrations of Pulp Mills. Deinked market Pulp Mills, on the other hand, are typically located close to large metropolitan areas, which can consistently provide large amounts of recovered paper and paperboard (McGraw-Hill, 2000).

Paper Mills are more widely distributed, located in proximity to pulping operations and/or near converting segment markets. Since the primary market for paperboard products is manufacturing, the distribution of Paperboard Mills is similar to that of the manufacturing industry in general.

Figure B2A-5 on the following pages shows the distribution of all facilities by State in the profiled paper segments, based on the 1992 Census of Manufactures.[2]

[2] The *1992 Census of Manufactures* is the most recent data available by SIC code and State.

Figure B2A-5: Number of Facilities in Profiled Paper and Allied Products Segments by State



Source: U.S. DOC, 1987, 1992, and1997.

B2A-3.2 Facility size

Most facilities in the three profiled industry segments fall in the middle employment size categories, with either 100 to 249, or 250 to 499 employees. However, larger facilities (those with 500 or more employees) account for the majority of the industries' value of shipments.

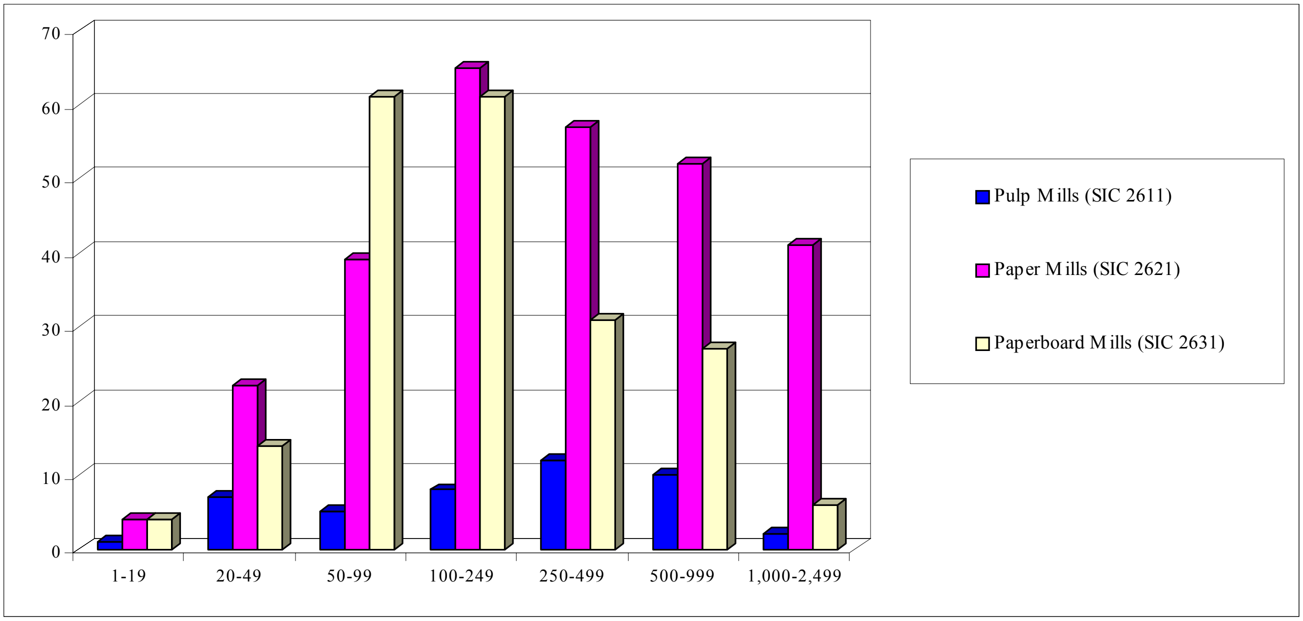
The number of independent Pulp Mills is smaller than the number of Paper Mills and Paperboard Mills, and Pulp Mills have considerably lower value of shipments. The larger facilities dominate value of shipments in all three segments, however:

- Twenty-seven percent of all *Pulp Mills* employ 500 employees or more. These facilities account for approximately 61 percent of the segment's value of shipments.
- Thirty-three percent of all *Paper Mills* have more than 500 employees. They account for 71 percent of the segment's value of shipments.
- Sixteen percent of all *Paperboard Mills* employ 500 people or more. These facilities account for 56 percent of the segment's value of shipments.

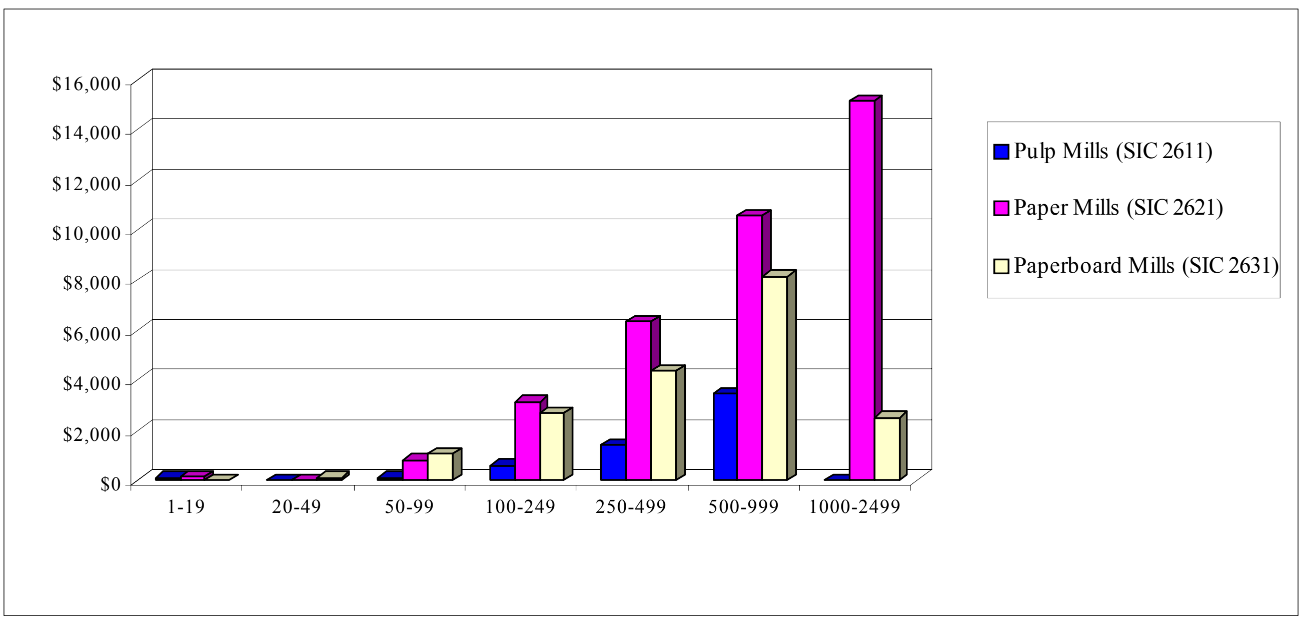
The distributions of the number of facilities and value of shipment by employment size class are presented in Figure B2A-6 below.

Figure B2A-6: Number of Facilities and Value of Shipments in 1992[a] by Employment Size Category for Profiled Paper and Allied Products Segments

Number of Facilities



Value of Shipments (in millions)



[a] The *1992 Census of Manufactures* is the most recent data available by SIC code and facility employment size.

Source: U.S. DOC, 1987, 1992, and 1997.

B2A-3.3 Firm size

For SIC codes 2611, 2621, and 2631, the Small Business Administration defines a small firm as having fewer than 750 employees. The size categories reported in the Statistics of U.S. Businesses (SUSB) do not correspond with the SBA size classifications, therefore preventing precise use of the SBA size threshold in conjunction with SUSB data. The SUSB data presented in Table B2A-8 below show the following size distribution in 2001:

- 26 of 40 (65 percent) firms in the *Pulp Mills* segment had less than 500 employees. Therefore, at least 65 percent of firms were classified as small. These small firms owned 28 facilities, or 55 percent of all facilities in the segment.

- 92 of 140 (66 percent) firms in the *Paper Mills* segment had less than 500 employees. These small firms owned 97, or 41 percent of all Paper Mills.

- 77 of 116 (66 percent) firms in the *Paperboard Mills* segment had less than 500 employees. Therefore, at least 66 percent of paperboard mills were classified as small. These firms owned 79, or 32 percent of all Paperboard Mills.

An unknown number of the firms with more than 500 employees have less than 750 employees, and would therefore also be classified as small firms. Table B2A-8 below shows the distribution of firms, facilities, and receipts for each profiled segment by employment size of the parent firm.

Table B2A-8: Number of Firms and Facilities by Firm Size Category for Profiled Paper and Allied Products Segments, 2001[a]

Employment Size Category	Pulp Mills		Paper Mills		Paperboard Mills	
	No. of Firms	No. of Facilities	No. of Firms	No. of Facilities	No. of Firms	No. of Facilities
0-19	11	11	34	34	34	34
20-99	8	8	20	20	16	16
100-499	7	9	38	43	27	29
500+	14	23	48	140	39	168
Total	***40***	***51***	***140***	***237***	***116***	***247***

[a] Before 1998, data were compiled in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC.*

Source: U.S. SBA, 1989-2001.

B2A-3.4 Concentration ratios

Concentration is the degree to which industry output is concentrated in a few large firms. Concentration is closely related to entry barriers, with more concentrated industries generally having higher barriers.

The four-firm ***concentration ratio*** (CR4) and the ***Herfindahl-Hirschman Index*** (HHI) are common measures of industry concentration. The CR4 indicates the market share of the four largest firms. For example, a CR4 of 72 percent means that the four largest firms in the industry account for 72 percent of the industry's total value of shipments. The higher the conentration ratio, the less competition there is in the industry, other things being equal.[3] An industry with a CR4 of more than 50 percent is generally considered concentrated. The HHI indicates concentration based on the largest 50 firms in the industry. It is equal to the sum of the squares of the market shares for the largest 50 firms in the industry. For example, if an industry consists of only three firms with market shares of 60, 30, and 10 percent, respectively, the HHI of this industry would be equal to 4,600 (602 + 302 + 102). The higher the index, the fewer the number of firms supplying the industry and the more concentrated the industry. Based on the U.S. Department of Justice's guidelines for evaluating mergers, markets in which the HHI is under 1000 are considered unconcentrated, markets in which the HHI is between 1000 and 1800 are considered to be moderately concentrated, and those in which the HHI is in excess of 1800 are considered to be concentrated.

Table B2A-9 shows that Pulp Mills have an HHI of 858, Paper Mills have an HHI of 392, and Paperboard Mills have an HHI of 438. At these HHI levels, all three industry segments appear relatively unconcentrated. With the majority of the firms in this industry having small market shares, this suggests limited potential for passing through to customers any increase in production costs resulting from regulatory compliance.

The concentration ratios for the three segments remained relatively stable between 1987 and 1992. The Pulp Mills segment has the highest concentration of the three segments, with a CR4 of 48 percent and a HHI of 858 in 1992. Recent mergers and acquisitions have led to an increase in concentration in the Paper and Paperboard segments. In the late 1990s, the top five U.S. firms controlled 38 percent of production capacity, with higher concentrations in individual product lines due to targeted consolidation and specialization (Ince, 1999). In 2001, only four firms had greater than 11 percent of the market, with none having a share greater than 17 percent. More than half of the firms in the paper industry had market shares under 2 percent (Paun et al. 2004). The Paper Mills and Paperboard Mills segments also account for most of the production of their primary products. The Pulp Mills segment accounts for a lower percentage of all pulp shipments, with pulp also commonly produced by integrated Paper and Paperboard Mills.

Table B2A-9: Selected Ratios for Profiled Paper and Allied Products Segments, 1987 and 1992[a]

SIC Code	Year	Total Number of Firms	Concentration Ratios				
			4 Firm (CR4)	8 Firm (CR8)	20 Firm (CR20)	50 Firm (CR50)	Herfindahl-Hirschman Index
2611	1987	26	44%	69%	99%	100%	743
	1992	29	48%	75%	98%	100%	858
2621	1987	122	33%	50%	78%	94%	432
	1992	127	29%	49%	77%	94%	392
2631	1987	91	32%	51%	77%	97%	431
	1992	89	31%	52%	80%	97%	438

[a] The *1992 Census of Manufactures* is the most recent concentration ratio data available by SIC code.

Source: U.S. DOC, 1987, 1992, and 1997.

[3]Note that the measured concentration ratio and the HHF are very sensitive to how the industry is defined. An industry with a high concentration in domestic production may nonetheless be subject to significant competitive pressures if it competes with foreign producers or if it competes with products produced by other industries (e.g., plastics vs. aluminum in beverage containers). Concentration ratios based on share of domestic production are therefore only one indicator of the extent of competition in an industry.

B2A-3.5 Foreign trade

This profile uses two measures of foreign competition: ***export dependence*** and ***import penetration***.

Import penetration measures the extent to which domestic firms are exposed to foreign competition in domestic markets. Import penetration is calculated as total imports divided by total value of domestic consumption in that industry: where domestic consumption equals domestic production plus imports minus exports. Theory suggests that higher import penetration levels will reduce market power and pricing discretion because foreign competition limits domestic firms' ability to exercise such power. Firms belonging to segments in which imports account for a relatively large share of domestic sales would therefore be at a relative disadvantage in their ability to pass-through costs because foreign producers would not incur costs as a result of the Phase III regulation. The estimated import penetration ratio for the entire U.S. manufacturing sector (NAICS 31-33) for 2001 is 22 percent. For characterizing the ability of industries to withstand compliance cost burdens, EPA judges that industries with import ratios close to or above 22 percent would more likely face stiff competition from foreign firms and thus be less likely to succeed in passing compliance costs through to customers.

Export dependence, calculated as exports divided by value of shipments, measures the share of a segment's sales that is presumed subject to strong foreign competition in export markets. The Phase III regulation would not increase the production costs of foreign producers with whom domestic firms must compete in export markets. As a result, firms in industries that rely to a greater extent on export sales would have less latitude in increasing prices to recover cost increases resulting from regulation-induced increases in production costs. The estimated export dependence ratio for the entire U.S. manufacturing sector for 2001 is 15 percent. For characterizing the ability of industries to withstand compliance cost burdens, EPA judges that industries with export ratios close to or above 15 percent are at a relatively greater disadvantage in potentially recovering compliance costs through price increases since export sales are presumed subject to substantial competition from foreign producers.

Table B2A-10 presents trade statistics for the Pulp Mills, and Paper and Paperboard Mills segments. Imports and exports play a much larger role in the Pulp Mills segment than for the other two segments. Import penetration and export dependence levels for the Pulp Mills segment were an estimated 87 and 88 percent, respectively, in 2001. The Paper and Paperboard Mills segments import penetration and export dependence ratios were 15 and 5 percent , respectively, in 2001. For Pulp Mills, the large share of domestic production that is exported and domestic consumption served by imports implies the industry faces significant foreign competition, limiting the industry's ability to pass through to customers any increase in production costs resulting from regulatory compliance. For Paper and Paperboard Mills, both measures of foreign competition are well below the U.S. manufacturing averages estimated for 2001. Given just these measures, it would be reasonable to assume that this segment does not face significant foreign competitive pressures, and would have more latitude in passing through to customers any increase in production costs resulting from regulatory compliance. However, foreign pressure is likely to increase as capacity in foreign countries, particularly China, continues to grow and exert pressure on the domestic market (McNutt, Cenatempo & Kinstrey, 2004). In addition, as noted above, the HHI of the Paper and Paperboard segments is 392 and 438 respectively, suggesting firms in these segments have small market shares, which would curtail their ability to pass through any increase in production costs.

Table B2A-10: Trade Statistics for Profiled Paper and Allied Products Segments

Year	Value of Imports (millions, $2003)	Value of Exports (millions, $2003)	Value of Shipments (millions, $2003)	Implied Domestic Consumption[a]	Import Penetration[b]	Export Dependence[c]
Pulp Mills						
1989	4,103	4,900	8,629	7,832	52.4%	56.8%
1990	3,692	4,258	8,079	7,513	49.1%	52.7%
1991	2,680	3,653	6,668	5,695	47.1%	54.8%
1992	2,573	3,958	6,685	5,300	48.5%	59.2%
1993	2,233	2,967	5,119	4,385	50.9%	58.0%
1994	2,675	3,458	5,650	4,867	55.0%	61.2%
1995	4,296	5,389	7,942	6,849	62.7%	67.9%
1996	2,928	3,780	6,200	5,348	54.7%	61.0%
1997	2,848	3,602	3,614	2,860	99.6%	99.7%
1998[d]	2,620	3,038	3,428	3,010	87.0%	88.6%
1999[d]	2,747	3,036	3,361	3,072	89.4%	90.3%
2000[d]	3,489	3,757	3,911	3,643	95.8%	96.1%
2001[d]	2,698	2,940	3,343	3,101	87.0%	87.9%
Total Percent Change 1989-2001	***-34%***	***-40%***	***-61%***	***-60.4%***		
Average Annual Growth Rate	***-3.4%***	***-4.2%***	***-7.6%***	***-7.4%***		
Paper and Paperboard Mills						
1989	9,900	4,054	69,541	75,387	13.1%	5.8%
1990	9,569	4,466	66,353	71,456	13.4%	6.7%
1991	8,664	5,075	60,502	64,091	13.5%	8.4%
1992	8,238	5,214	59,839	62,863	13.1%	8.7%
1993	8,636	5,009	57,700	61,327	14.1%	8.7%
1994	8,628	5,634	62,484	65,478	13.2%	9.0%
1995	11,740	7,384	79,893	84,249	13.9%	9.2%
1996	10,305	7,136	67,360	70,529	14.6%	10.6%
1997	8,914	3,602	63,461	68,773	13.0%	5.7%
1998[d]	9,565	3,038	63,591	70,118	13.6%	4.8%
1999[d]	9,620	3,036	63,735	70,319	13.7%	4.8%
2000[d]	10,399	3,757	65,887	72,529	14.3%	5.7%
2001[d]	9,818	2,940	59,731	66,609	14.7%	4.9%
Total Percent Change 1989-2001	***-1%***	***-27%***	***-14.1%***	***-11.6%***		
Average Annual Growth Rate	***-0.1%***	***-2.6%***	***-1.3%***	***-1.0%***		

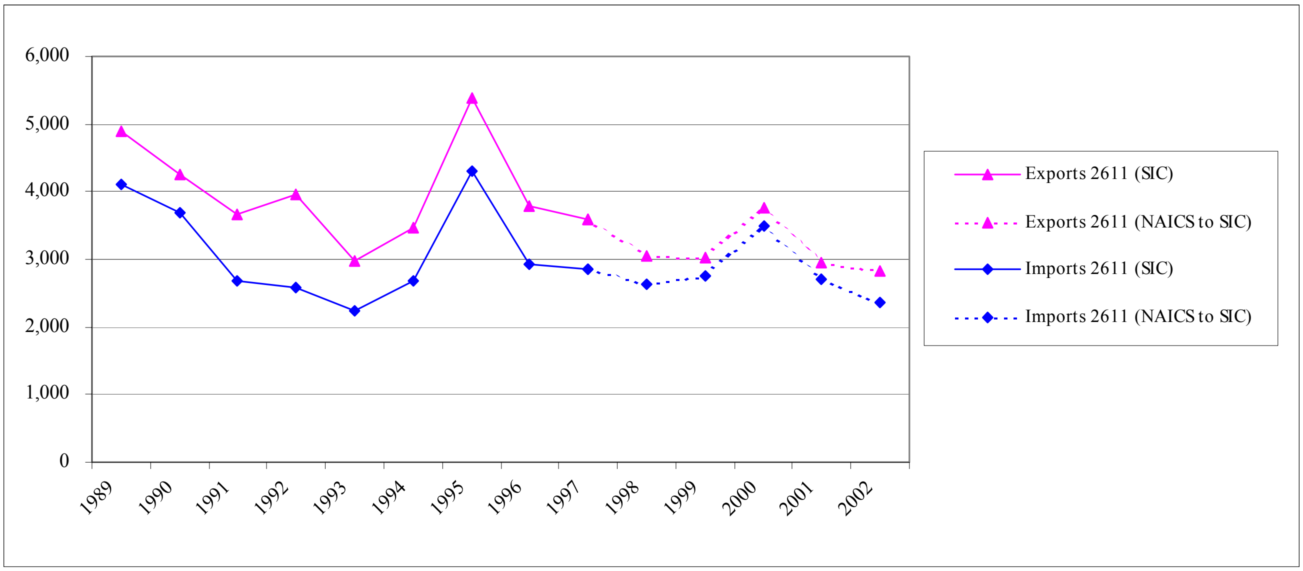
[a] Calculated by EPA as shipments + imports - exports.
[b] Calculated by EPA as imports divided by implied domestic consumption.
[c] Calculated by EPA as exports divided by shipments.
[d] Before 1998, data were compiled in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

Source: *U.S. DOC, 2001.*

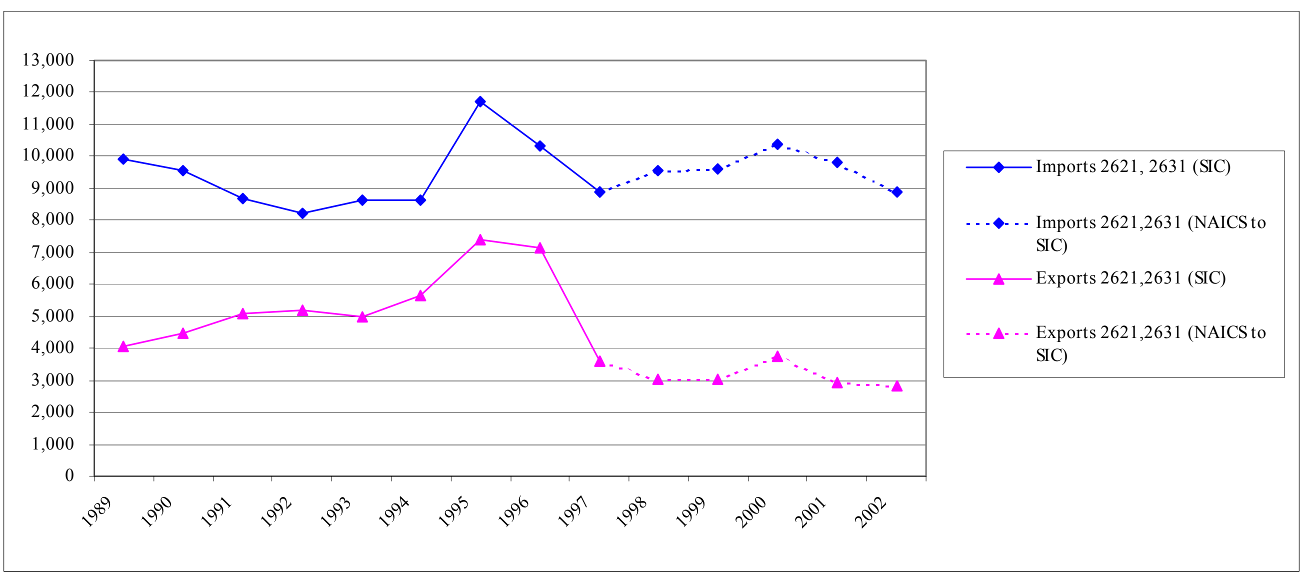
Figure B2A-7 shows that the value of imports and exports peaked in the mid-1990s, before dropping and rebounding in 2000. As expected, values of both dropped again in 2001 and 2002, as the global economy fell into recession.

Figure B2A-7: Value of Imports and Exports for Profiled Paper and Allied Products Segments (millions,$2003)

Pulp Mills



Paper and Paperboard Mills



[a] Before 1998, data were compiled in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

Source: U.S. DOC, 2001.

B2A-4 Financial Condition and Performance

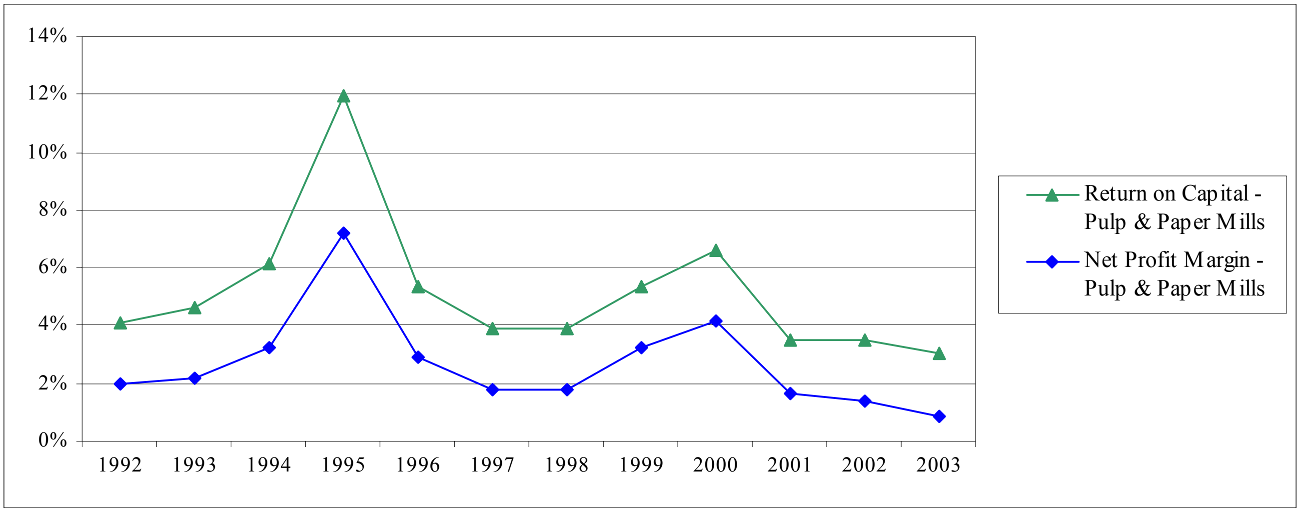
Financial performance in the paper and allied products industry is closely linked to macroeconomic cycles, both in the domestic market and those of key foreign trade partners, and the resulting levels of demand. Many pulp producers, for example, were not very profitable during most of the 1990s as chronic oversupply, cyclical demand, rapidly fluctuating operating rates, sharp inventory swings, and uneven world demand has plagued the global pulp market for more than a decade (Stanley, 2000).

Net Profit Margin is calculated as after-tax income before nonrecurring gains and losses as a percentage of sales or revenue, and measures profitability, as reflected in the conventional accounting concept of net income. Over time, the firms in an industry, and the industry collectively, must generate a sufficient positive profit margin if the industry is to remain economically viable and attract capital. Year-to-year fluctuations in profit margin stem from several factors, including: variations in aggregate economic conditions (including international and U.S. conditions), variations in industry-specific market conditions (e.g., short-term capacity expansion resulting in overcapacity), or changes in the pricing and availability of inputs to the industry's production processes (e.g., the cost of energy to the pulp and paper process). The extent to which these fluctuations affect an industry's profitability, in turn, depends heavily on the fixed vs. variable cost structure of the industry's operations. In a capital intensive industry such as the pulp and paper industry, the relatively high fixed capital costs as well as other fixed overhead outlays, can cause even small fluctuations in output or prices to have a large positive or negative affect on profit margin.

Return on Total Capital is calculated as annual net profit, plus one-half of annual long-term interest, divided by the total of shareholders' equity and long-term debt (total capital). This concept measures the total productivity of the capital deployed by a firm or industry, regardless of the financial source of the capital (i.e., equity, debt, or liability element). As such, the return on total capital provides insight into the profitability of a business' assets independent of financial structure and is thus a "purer" indicator of asset profitability than return on equity. In the same way as described for *net profit margin*, the firms in an industry, and the industry collectively, must generate over time a sufficient return on capital if the industry is to remain economically viable and attract capital. The factors causing short-term variation in *net profit margin* will also be the primary sources of short-term variation in *return on total capital*.

Figure B2A-8 below shows trends in net profit margins and return on total capital for the pulp and paper industry between 1992 and 2003. The table shows considerable volatility in the trend. Profitability was low between 1988 and 1993, reflecting oversupply in world markets and decreasing shipments from U.S. producers (McGraw-Hill, 2000). By the mid-1990s, financial performance improved as demand rebounded. Financial performance weakened again in 2000 through 2003, reflecting slower growth in both the U.S. and the world economy. Coupled with overproduction in the U.S. and global markets, these factors led to deteriorating financial performance in these years. Industry analysts currently anticipate stronger financial performance for the pulp and paper industry for 2004 (Value Line, 2004). With continued improvement in the U.S. economy, the outlook for the industry should be stronger in subsequent years.

Figure B2A-8: Net Profit Margin and Return on Capital for Pulp and Paper Mills



Source: Value Line, 1992-2003.

B2A-5 FACILITIES OPERATING COOLING WATER INTAKE STRUCTURES

Point source facilities that use or propose to use a cooling water intake structure that withdraws cooling water directly from a surface waterbody of the United States, are potentially subject to Section 316(b) of the Clean Water Act. In 1982, the paper and allied products industry withdrew 534 billion gallons of cooling water, accounting for approximately 0.7 percent of total industrial cooling water intake in the United States. The industry ranked 5th in industrial cooling water use, behind the electric power generation industry, and the chemical, primary metals, and petroleum industries (1982 Census of Manufactures).

This section provides information for facilities in the profiled paper and allied products segments potentially subject to the proposed regulation. Existing facilities that meet all of the following conditions are potentially subject to the proposed regulation:[4]

- 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;
- Have a National Pollutant Discharge Elimination System (NPDES) permit or are required to obtain one; and
- Have a design intake flow of greater than 2 million gallons per day (MGD).

The proposed regulation 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 section focuses on the estimated 235 facilities nationwide in the profiled paper and allied products segments identified in EPA's 2000 Section 316(b) Industry Survey as being potentially subject to the proposed regulation.[5] Information collected in

[4]The proposed regulation also applies to existing electric generating facilities as well as certain facilities in the oil and gas extraction industry. See Chapter B4 and B5 and Part C of this document for more information on these industries.

[5]EPA applied sample weights to the sampled 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

the Detailed Industry Questionnaire found that an estimated 41 out of 60 Pulp Mills (68 percent), 133 out of 290 Paper Mills (46 percent), and 52 out of 190 Paperboard Mills (27 percent) meet the characteristics of a potential Phase III facility.

B2A-5.1 Waterbody and Cooling System Type

Table B2A-11 reports the distribution of potential Phase III facilities in the profiled paper and allied products segments by type of waterbody and cooling system. The table shows that most of the facilities have either a once-through system (112, or 50 percent) or employ a combination of a once-through and closed system (47, or 21 percent). Thirty-one facilities (14 percent) have a recirculating system, while the remaining thirty-five facilities (16 percent) employ some other type of cooling system. The majority of paper facilities draw water exclusively from either a freshwater water stream or river (172, or 76 percent). All six of the facilities that withdraw from an estuary, the most sensitive type of waterbody, use a once-through cooling system. Plants with once-through cooling water systems withdraw between 70 and 98 percent more water than those with recirculating systems.

to the Information Collection Request (U.S. EPA, 2000).

Table B2A-11: Number of Potential Phase III facilities by Water Body Type and Cooling System for Profiled Paper and Allied Products Segments

Waterbody Type	Recirculating		Combination		Once-Through		Other		Total
	No.	% of Total	No.	% of Total	No.	% of Total	No.	% of Total	
Pulp Mills									
Freshwater River/ Stream	12	36%	10	30%	9	27%	1	3%	33
Lake/ Reservoir	0	0%	0	0%	0	0%	3	100%	3
Great Lake	0	0%	0	0%	5	100%	0	0%	5
Total[a]	***12***	***29%***	***10***	***24%***	***14***	***34%***	***4***	***10%***	***41***
Paper Mills									
Estuary/ Tidal River	0	0%	0	0%	3	100%	0	0%	3
Freshwater River/ Stream	10	11%	14	15%	54	57%	16	17%	94
Lake/ Reservoir	0	0%	7	41%	5	29%	6	35%	17
Great Lake	0	0%	0	0%	14	78%	5	28%	18
Total[a]	***10***	***8%***	***21***	***16%***	***75***	***56%***	***27***	***20%***	***133***
Paperboard Mills									
Estuary/ Tidal River	0	0%	0	0%	3	100%	0	0%	3
Freshwater River/ Stream	9	20%	16	36%	18	41%	2	5%	44
Lake/ Reservoir	0	0%	0	0%	2	40%	3	60%	5
Total[a]	***9***	***17%***	***16***	***31%***	***23***	***44%***	***5***	***10%***	***52***
Total Paper and Allied Products Industry									
Estuary/ Tidal River	0	0%	0	0%	6	100%	0	0%	6
Freshwater River/ Stream	31	18%	40	23%	81	47%	19	11%	172
Lake/ Reservoir	0	0%	7	29%	6	25%	11	46%	24
Great Lake	0	0%	0	0%	18	78%	5	22%	23
Total[a]	***31***	***14%***	***47***	***21%***	***112***	***50%***	***35***	***16%***	***225***

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

Source: U.S. EPA, 2000.

B2A-5.2 Facility Size

The 316(b) sample facilities are generally larger than facilities in the pulp and paper industry as a whole, as reported in the Census and discussed previously:

- Twenty-nine percent of all facilities in the *Pulp Mills* segment (SIC 2611) had fewer than 100 employees in 1992, compared with 7 percent of the potential Phase III facilities.

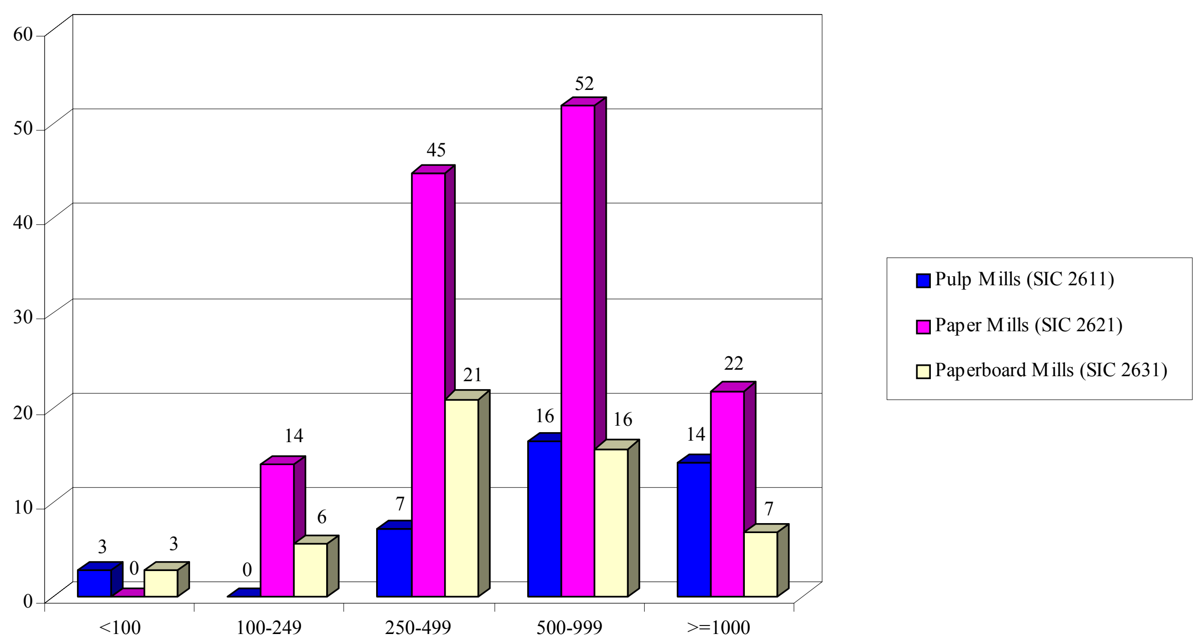
- Twenty-three percent of all facilities in the *Paper Mills* segment (SIC 2621) had fewer than 100 employees in 1992; none of the potential Phase III facilities in that segment fall into that employment category.

- Thirty-nine percent of all facilities in the *Paperboard Mills* segment (SIC 2631) had fewer than 100 employees, compared with 5 percent of the potential Phase III facilities.

The majority of Section 316(b) Pulp Mills, 31 or 75 percent, employ 500 employees or greater. The Section 316(b) Paper Mills and Paperboard Mills are more evenly distributed across employment categories. Forty-five Paper Mill facilities (34 percent) employ 250-499 employees, and 74 facilities (56 percent) employ 500 employees or more. Twenty-one, or 40 percent, of Paperboard Mills employ 250-499 employees, and 23 facilities (43 percent) employ more than 500 employees.

Figure B2A-9 shows the number of potential Phase III facilities in the profiled pulp and paper segments by employment size category.

Figure B2A-9: Number of Potential Phase III facilities by Employment Size for Profiled Paper and Allied Products Segments



Source: U.S. EPA, 2000.

B2A-5.3 Firm Size

EPA used the Small Business Administration (SBA) small entity size standards to determine the number of potential Phase III facilities in the three profiled paper segments that are owned by small firms. Firms in this industry are considered small if they employ fewer than 750 people.

Table B2A-12 shows that potential Phase III facilities in this industry are predominantly owned by large firms. Large firms own 93 percent (38 facilities) of Pulp Mills, 86 percent (114 facilities) of Paper Mills, and all of the Paperboard Mills. Small firms own three Pulp Mills and 18 Paper Mills.

Table B2A-12: Number of Potential Phase III facilities in Profiled Paper and Allied Products Segments by Firm Size

SIC Code	SIC Description	Large		Small		Total
		Number	% of SIC	Number	% of SIC	
2611	Pulp Mills	38	93%	3	7%	41
2621	Paper Mills	114	86%	18	14%	133
2631	Paperboard Mills	52	100%	0	0%	52
	Total	***204***	***91%***	***21***	***9%***	***225***

Source: U.S. EPA, 2000; U.S. SBA 2000; D&B, 2001.

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Chapter B2B: Chemicals and Allied Products (SIC 28)

EPA's *Detailed Industry Questionnaire*, hereafter referred to as the DQ, identified thirteen 4-digit SIC codes in the Chemical and Allied Products Industry (SIC 28) with at least one existing facility that operates a CWIS, holds a NPDES permit, withdraws equal to or greater than two million gallons per day (MGD) from a water of the United States, and uses at least 25 percent of its intake flow for cooling purposes (facilities with these characteristics are hereafter referred to as facilities potentially subject to the Phase III regulation or "potential Phase III facilities").

For each of the fifteen SIC codes, Table B2B-1 below provides a description of the industry segment, a list of primary products manufactured, the total number of detailed questionnaire respondents (weighted ro represent national results), and the number and percent of potential Phase III facilities.

CHAPTER CONTENTS

Table B2B-1: Potential Phase III facilities in the Chemicals and Allied Products Industry (SIC 28)

SIC	SIC Description	Important Products Manufactured	Number of facilities[a] Total	Potential Phase III facilities[b]	%
		Inorganic Chemicals (SIC 281)[c]			
2812	Alkalies and Chlorine	Alkalies, caustic soda, chlorine, and soda ash	28	20	70%
2813	Industrial Gases	Industrial gases (including organic) for sale in compressed, liquid, and solid forms	110	4	4%
2816	Inorganic Pigments	Black pigments, except carbon black, white pigments, and color pigments	26	9	35%
2819	Industrial Inorganic Chemicals, Not Elsewhere Classified	Miscellaneous other industrial inorganic chemicals	271	30	11%
		Total Inorganic Chemicals	***435***	***64***	***15%***
		Plastics Material and Resins (SIC 282)			
2821	Plastics Material and Synthetic Resins, and Nonvulcanizable Elastomers	Cellulose plastics materials; phenolic and other tar acid resins; urea and melamine resins; vinyl resins; styrene resins; alkyd resins; acrylic resins; polyethylene resins; polypropylene resins; rosin modified resins; coumarone-indene and petroleum polymer resins; miscellaneous resins	*305*	*19*	*6%*

Table B2B-1: Potential Phase III facilities in the Chemicals and Allied Products Industry (SIC 28)

SIC	SIC Description	Important Products Manufactured	Number of facilities[a]		
			Total	Potential Phase III facilities[b]	%
		Organic Chemicals (SIC 286)[d]			
2865	Cyclic Organic Crudes and Intermediates, and Organic Dyes and Pigments	Aromatic chemicals, such as benzene, toluene, mixed xylenes naphthalene, synthetic organic dyes, and synthetic organic pigments	59	9	15%
2869	Industrial Organic Chemicals, Not Elsewhere Classified	Aliphatic and other acyclic organic chemicals; solvents; polyhydric alcohols; synthetic perfume and flavoring materials; rubber processing chemicals; plasticizers; synthetic tanning agents; chemical warfare gases; and esters, amines, etc.	364	52	14%
		Total Organic Chemicals	***423***	***61***	***14%***
		Other Chemical Segments			
2823	Cellulosic Manmade Fibers	Cellulose acetate and regenerated cellulose such as rayon by the viscose or cuprammonium process	7	1	14%
2824	Manmade Organic Fibers, Except Cellulosic	Regenerated proteins, and polymers or copolymers of such components as vinyl chloride, vinylidene chloride, linear esters, vinyl alcohols, acrylonitrile, ethylenes, amides, and related polymeric materials	36	13	36%
2833	Medicinal Chemicals and Botanical Products	Agar-agar and similar products of natural origin, endocrine products, manufacturing or isolating basic vitamins, and isolating active medicinal principals such as alkaloids from botanical drugs and herbs	33	2	6%
2834	Pharmaceutical Preparations	Intended for final consumption, such as ampoules, tablets, capsules, vials, ointments, medicinal powders, solutions, and suspensions	91	4	5%
2873	Nitrogenous Fertilizers	Ammonia fertilizer compounds and anhydrous ammonia, nitric acid, ammonium nitrate, ammonium sulfate and nitrogen solutions, urea, and natural organic fertilizers (except compost) and mixtures	60	9	14%
2899	Chemicals and Chemical Preparations, Not Elsewhere Classified	Fatty acids; essential oils; gelatin (except vegetable); sizes; bluing; laundry sours; writing and stamp pad ink; industrial compounds; metal, oil, and water treating compounds; waterproofing compounds; and chemical supplies for foundries	162	4	3%
		Total Other	***389***	***34***	***9%***
		Total Chemicals and Allied Products (SIC 28)			
		Total SIC Code 28	***1,552***	***178***	***11%***

[a] Number of weighted detailed questionnaire survey respondents.
[b] Individual numbers may not add up due to independent rounding.
[c] SIC code 281 is officially titled "Industrial Inorganic Chemicals." However, to avoid confusion with SIC code 2819, "Industrial Inorganic Chemicals, Not Elsewhere Classified," this profile refers to SIC code 281 as the "Inorganic Chemicals segment."
[d] SIC code 286 is officially titled "Industrial Organic Chemicals." However, to avoid confusion with SIC code 2869, "Industrial Organic Chemicals, Not Elsewhere Classified," this profile refers to SIC code 286 as the "Organic Chemicals segment."

Source: U.S. EPA, 2000; Executive Office of the President, 1987.

The table shows that an estimated 178 out of 1,552 facilities (or 11 percent) in the Chemicals and Allied Products Industry (SIC 28) are potentially subject to the proposed Phase III regulation. EPA also estimated the percentage of total production that occurs at facilities potentially subject to the proposed regulation. Total value of shipments for the chemicals and allied products industry from the 1998 Annual Survey of Manufacturers is $268 billion. Value of shipments, a measure of the dollar value of production, was selected for the basis of this estimate. Because value of shipments data were not collected using the DQ, these data were not available for the sample of Phase III manufacturing facilities potentially subject to the proposed regulation. Total revenue, as reported on the DQ, was used a close approximation for value of shipments for these facilities. EPA estimated the total revenue of facilities in the chemicals industry potentially subject to the proposed regulation is $61.2 billion. Therefore, EPA estimates that 23 percent of total production in the chemicals industry occurs at facilities potentially subject to the proposed regulation.

The responses to the Detailed Questionnaire indicate that three chemical segments account for 80 percent of the chemicals industry potential Phase III facilities: (1) Inorganic Chemicals (including SIC codes 2812, 2813, 2816, and 2819); (2) Plastics Material and Resins (SIC code 2821); and (3) Organic Chemicals (including SIC codes 2865 and 2869). Of the 177 potential Phase III facilities in the Chemical industry, 64 facilities, or 36 percent, belong to the Inorganic Chemicals segment, 61, or 35 percent, belong to the Organic Chemicals segment, and 19, or 11 percent, belong to the Plastics and Resins segment. This profile therefore provides detailed information for these three industry groups.

Table B2B-2 on the following page provides the cross-walk between SIC codes and NAICS codes for the profiled chemical SIC codes. The table shows that alkalies and chlorine (SIC 2812), industrial gases (SIC 2813), Plastics Material and Synthetic Resins, and Nonvulcanizable Elastomers (SIC 2821) have one-to-one relationships to NAICS codes. The other SIC codes in the three profiled chemical segments correspond to two or more NAICS codes.

Table B2B-2: Relationship between SIC and NAICS Codes for the Chemicals and Allied Products Industry (1997)

SIC Code	SIC Description	NAICS Code	NAICS Description	Establishments	Value of Shipments ($000)	Employment
Inorganic Chemicals (SIC 281)						
2812	Alkalies and Chlorine	325181	Alkalies and chlorine manufacturing	39	2,465,183	4,859
2813	Industrial Gases	325120	Industrial gas manufacturing (pt)	630	3,952,006	8,787
2816	Inorganic Pigments	325131	Inorganic dye and pigment manufacturing (pt)	74	3,734,497	8,608
		325182	Carbon black manufacturing (pt)	0	0	0
2819	Industrial Inorganic Chemicals, Not Elsewhere Classified	325131	Inorganic dye and pigment manufacturing (pt)	0	0	0
		325188	All other basic inorganic chemical manufacturing (pt)	638	D	50,000 to 99,999
		325998	All other miscellaneous chemical product and preparation manufacturing (pt)	22	380,156	1,484
		331311	Alumina refining	7	1,257,211	3,153
Plastics Material and Resins (SIC 282)						
2821	Plastics Material and Synthetic Resins, and Nonvulcanizable Elastomers	325211	Plastics material and resin manufacturing	529	44,478,404	60,764
Organic Chemicals (SIC 286)						
2865	Cyclic Organic Crudes and Intermediates, and Organic Dyes and Pigments	325110	Petrochemical manufacturing (pt)	22	3,665,285	3,007
		325132	Synthetic organic dye and pigment manufacturing	122	2,692,860	8,681
		325192	Cyclic crude and intermediate manufacturing	51	6,571,093	8,183
2869	Industrial Organic Chemicals, Not Elsewhere Classified	325110	Petrochemical manufacturing (pt)	32	16,869,465	7,936
		325120	Industrial gas manufacturing (pt)	13	1,279,462	3,705
		325188	All other basic inorganic chemical manufacturing (pt)	2	D	250 to 499
		325193	Ethyl alcohol manufacturing	39	1,287,273	1,890
		325199	All other basic organic chemical manufacturing (pt)	654	52,294,254	86,793

D = Withheld to avoid disclosure.

Source: U.S. DOC, 1997.

B2B-1 SUMMARY INSIGHTS FROM THIS PROFILE

A key purpose of this profile is to provide insight into the ability of Chemicals firms that would be potentially subject to the proposed Phase III regulation, to absorb compliance costs without material adverse economic/financial effects. Two important factors in the ability of the industry's ability to withstand compliance costs are: (1) the extent to which the industry may be expected to shift compliance costs to its customers through price increases and (2) the financial health of the industry and its general business outlook.

Likely Ability to Pass Compliance Costs Through to Customers
As reported in the following sections of this profile, the chemicals industry has variable level of concentration, with some industry segments exhibiting relatively low concentration while others show somewhat higher concentration. Regardless of the domestic concentration level and its implications for market power, the U.S. chemicals industry faces increasing competitive pressure from abroad, which substantially limits any apparent ability of firms in this industry to pass through to customers a significant portion of their compliance-related costs. In addition, the relatively low share of total industry output that is produced in potential Phase III facilities, an estimated 23 percent, also argues against complying firms' ability to shift compliance costs to customers. For these reasons, in its analysis of regulatory impacts for the chemicals industry, EPA assumed that complying firms would be unable to pass compliance costs through to customers: i.e., complying facilities must absorb all compliance costs within their financial condition at the time of compliance (see following sections and Appendix 3 of *Chapter B3: Economic Impact Analysis for Manufacturers* for further information).

Financial Health and General Business Outlook
Over the past decade, the Chemicals industry, like other U.S. manufacturing industries, has experienced a range of economic/financial conditions, including substantial challenges. In the early 1990s, the domestic chemicals industry was affected by reduced U.S. demand as the economy entered a recessionary period Although domestic market conditions improved by mid-decade, an oversupply of crude oil, weakness in Asian markets, along with other domestic factors, dealt a serious blow to refiners in 1998. More recently, as the U.S. economy began recovery from its economic weakness, the domestic chemicals industry is showing signs of recovery with higher demand levels and improving financial performance in 2003. Although the industry weathered difficult periods over the past few years, the strengthening of the industry's financial condition and general business outlook suggest improved ability to withstand additional regulatory compliance costs without a material financial impact.

B2B-2 DOMESTIC PRODUCTION

The U.S. chemical and allied products industry includes a large number of companies that, in total, produce more than 70,000 different chemical products. These products range from commodity materials used in other industries to finished consumer products such as soaps and detergents. The industry accounts for nearly 12 percent of U.S. manufacturing value added, and produces approximately two percent of total national gross domestic product (McGraw-Hill, 2000).

Raw materials containing hydrocarbons such as oil, natural gas, and coal are primary feedstocks for the production of organic chemicals. Inorganic chemicals are chemicals that do not contain carbon but are produced from other gases and minerals (McGraw-Hill, 2000).

The chemicals and allied products industry is highly energy intensive, consuming about 7 percent of total annual U.S. energy output (McGraw-Hill, 2000). It is one of the largest industrial users of electric energy and also consumes large amounts of oil and natural gas. In total, the industry accounts for approximately seven percent of total U.S. energy consumption, including 11 percent of all natural gas use. Just over 50 percent of the industry's energy consumption is used as feedstock in the production of chemical products. The remaining energy consumption is for fuel and power for production processes. Oil accounts for approximately 42 percent of total energy consumption by the industry. For some products, e.g., petrochemicals, energy costs account for up to 85 percent of total production costs. Overall, total energy costs represent seven percent of the value of chemical industry shipments (S&P, 2001).

B2B-2.1 Output

Figure B2B-1 shows constant dollar ***value of shipments*** and ***value added*** for the three profiled segments between 1987 and 2001[1]. Value of shipments and value added are two common measures of manufacturing output. They provide insight into the overall economic health and outlook for an industry. Value of shipments is the sum of the receipts a manufacturer earns from the sale of its outputs; it indicates the overall size of a market or the size of a firm in relation to its market or competitors. Value added measures the value of production activity in a particular industry. It is the difference between the value of shipments and the value of inputs used to make the products sold.

The Organic Chemicals segment experienced a decrease in both value of shipments and value added between 1988 and 1993, followed by volatility through 1998. The mid 1990s were marked by increased competition in the global market for petrochemicals, which comprise the majority of organic chemical products. The increased competition stems from the considerable capacity expansions for these products seen in developing nations. (McGraw-Hill, 2000). Value of shipments for the segment increased through 2000, while value added remained flat. Both value of shipments and value added declined significantly in 2001as the segment faced decreased demand due to the economic slowdown.

The Plastics Material and Resins and Inorganic Chemicals segments remained somewhat more stable over the period between 1987 and 2001. In the early 1990s, domestic producers benefitted from the relatively weak dollar, which made U.S. products more competitive in the global market. During the later part of the 1990s, the strength of the U.S. economy bolstered domestic end-use markets, offsetting the effect of reduced U.S. export sales, which resulted from increased global competition and a strengthened dollar (McGraw-Hill, 2000). The global economic slowdown that began in 2000 led to decreased production, in particular, of chemical goods that are used in the production processes of other industries, notably steel, apparel, textiles, forest products, and technology.

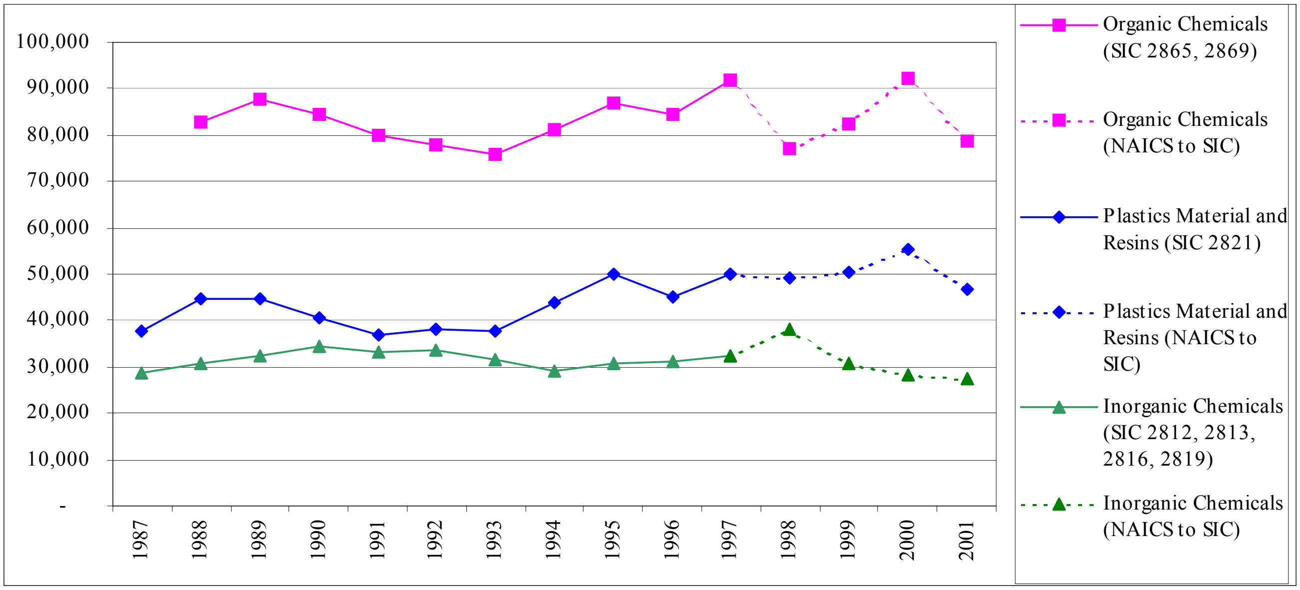
Since 2000, these three segments of the chemical industry have experienced significant challenges and weakened financial performance. In 2001, the industry faced high energy and raw material prices at the start of the year, and overcapacity, weak demand, and slowing global economies at the end of the year. All these factors led to poor financial results for the year (C&EN, 2001). Production increased slightly in 2002, and financial results improved, as cost cutting efforts, including significant layoffs, improved earnings (C&EN, 2002). Firms began 2003 with hopes of a turnaround, but continued to face the same problems as the previous two years, as industry was forced to reduce employment and spending against declining earnings (C&EN, 2003c).

Currently, the industry continues to face high raw material and energy costs, as well as an increase in competition from abroad. The past three years have seen the industry struggle to maintain earnings against the global economic decline. Although the U.S. economy has improved recently, the chemical industry has lagged in increasing growth of sales and earnings. This may change in 2004, as the American Chemistry Council reported that the chemical industry should experience positive growth only slightly lower than GDP in 2004 (C&EN, 2003c). This should better position firms to incur costs associated with regulatory compliance.

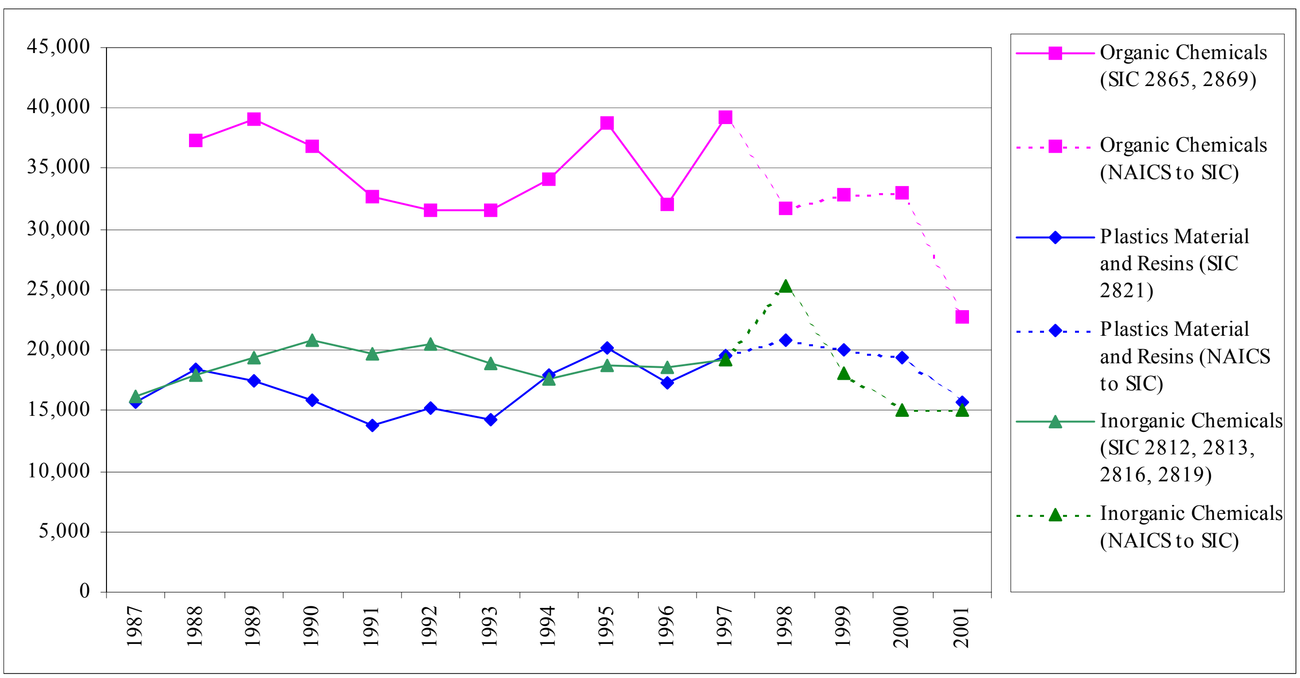
[1]Terms highlighted in bold and italic font are further explained in the glossary.

Figure B2B-1: Value of Shipments and Value Added for Profiled Chemical Segments (in millions, $2003)

Value of Shipments



Value Added



[a] Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

Source: U.S. DOC, 1988-1991, 1993-1996, and 1998-2001; U.S. DOC, 1987, 1992, and 1997.

Table B2B-3 provides the Federal Reserve System's index of industrial production for the three profiled segments, which shows trends in production since 1997. This index reflects total output in physical terms, whereas value of shipments and value added reflects the value of production. Table B2B-3 shows varying trends in the three segments since 1997, but sharp declines in production in all three segments in 2000 or 2001. These declines were caused by the marked slowdown in the U.S. economy, which affected demand in major chemical-using segments such as steel, apparel, textiles, forest products, and the technology sectors (Chemical Marketing Reporter, 2001). Production declines continued through 2001, but rebounded somewhat in 2002 before dipping again in 2003.

Table B2B-3: Chemicals Industry Industrial Production Index

Year	Basic Inorganic Chemicals[a]		Plastics Material and Resins[b]		Organic Chemicals[c]	
	Index 1997=100	Percent Change	Index 1997=100	Percent Change	Index 1997=100	Percent Change
1989	105.1	n/a	78.8	n/a	89.6	n/a
1990	111.9	6.4%	79.6	1.0%	91.6	2.3%
1991	106.6	-4.7%	76.5	-3.8%	87.7	-4.3%
1992	107.2	0.6%	83.2	8.7%	89.1	1.6%
1993	102.1	-4.8%	81.7	-1.9%	86.4	-3.0%
1994	96.6	-5.4%	93.2	14.1%	91.2	5.5%
1995	97.5	1.0%	93.9	0.8%	90.4	-0.8%
1996	98.0	0.5%	91.0	-3.2%	90.2	-0.3%
1997	100.0	2.1%	100.1	10.1%	100.0	10.9%
1998	105.5	5.5%	107.9	7.8%	92.2	-7.8%
1999	106.0	0.4%	112.4	4.1%	99.1	7.5%
2000	96.8	-8.7%	112.3	-0.1%	99.9	0.8%
2001	95.6	-1.3%	100.2	-10.8%	88.2	-11.7%
2002	95.8	0.2%	105.8	5.5%	94.9	7.5%
2003	92.9	-3.0%	104.3	-1.4%	94.6	-0.3%
Total Percent Change 1989-2000	***-11.6%***		***32.3%***		***5.6%***	
Average Annual Growth Rate	***-0.9%***		***2.0%***		***0.4%***	

[a] Includes NAICS 32512-8.
[b] Includes NAICS 325211.
[c] Includes NAICS 32511,9.

Source: Federal Reserve Board, 2004.

B2B-2.2 Prices

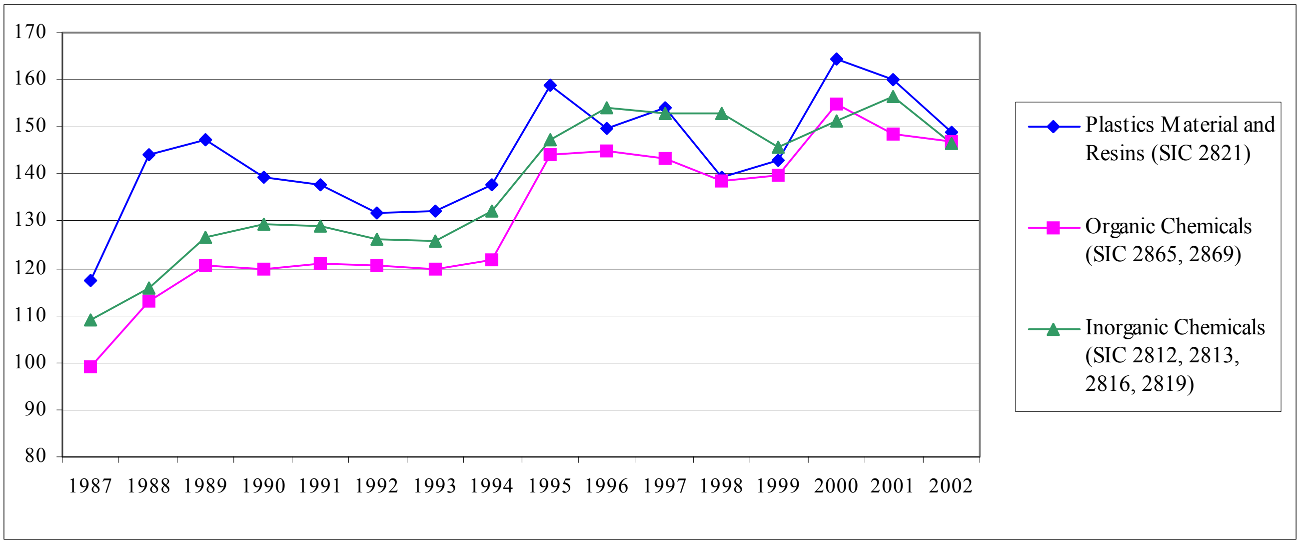
The ***producer price index*** (PPI) measures price changes, by segment, from the perspective of the seller, and indicates the overall trend of product pricing, and thus supply-demand conditions, within a segment.

Figure B2B-2 shows the producer price index for the profiled chemical segments. Selling prices for the products of the Organic and Inorganic Chemicals segments increased from 1987 to 1989 and remained stable through 1994. Between 1994 and 1995, prices increased sharply, followed by a period of relatively stable prices through 1999. The sharp price rises for Organic Chemicals and Plastics Material and Resins in 2000 resulted in part from increases in the price of natural gas, which is the feedstock for 70 percent of U.S. ethylene production. High natural gas prices put U.S. organic chemicals and, to a lesser extent, plastic resin producers at a disadvantage relative to foreign producers who rely on naphta and gas oil as a feedstock. Natural gas prices declined, however, in 2001 easing pressure on U.S. producers (Chemical Marketing Reporter, 2001). Price increases for Plastics Material and Resins also reflected a shift by U.S. producers away from production of commodity resins to speciality and higher-value-added products (McGraw-Hill, 2000). Prices for Plastics Material and Resins followed a trend similar to the other two chemical industry segments but with larger fluctuations (see Figure B2B-2). For the chemical industry in general, prices rose 4 percent in 2002, increased further in 2003, with the producer price index reaching 165 (C&EN, 2003c).

Chemical and plastics prices fluctuate in large part as a result of varying energy prices. Basic petrochemicals, which comprise the majority of organic chemical products, depend heavily on energy commodities as inputs to the production process – energy input costs may account for up to 85 percent of total product costs. The prices of natural gas and oil therefore influence the production costs and the selling price for these products. High basic petrochemical prices affect prices for chemical intermediates and final end products, including organic chemicals and plastics.

Another factor influencing prices for commodity chemical products is the cyclical nature of market supply and demand conditions. The Plastics, Organic Chemicals, and Inorganic Chemicals segments are characterized by large capacity additions which can lead to fluctuations in prices in response to imbalances in supply and demand.

Figure B2B-2: Producer Price Indexes for Profiled Chemical Segments



[a] Indices are an average of each SIC code's PPI within each segment

Source: BLS, 2002.

B2B-2.3 Number of Facilities and Firms

According to the Statistics of U.S. Businesses, the number of facilities in the Inorganic Chemicals segment remained relatively stable between 1989 and 1997, followed by four consecutive years of decreases in the number of facilities. The other two segments saw overall increases in the number of facilities over the 1989 to 2001 time period, though the Organic Chemicals segment saw declines in 1999 through 2001. The Plastics Material and Resins segment saw significant increases in the number of facilities reported between 1993 and 1996, reflecting growth in the demand for plastics in a number of end-uses (McGraw-Hill, 2000). Table B2B-4 shows the downward trend in the number of facilities producing inorganic chemical products following a peak in 1991. The decrease is partly attributable to the consolidation within the Inorganic Chemicals segment (S&P, 2001).

Table B2B-4: Number of Facilities for Profiled Chemical Segments[a]

Year	Inorganic Chemicals		Plastics Material and Resins		Organic Chemicals	
	Number of Facilities	Percent Change	Number of Facilities	Percent Change	Number of Facilities	Percent Change
1989	1,387	n/a	504	n/a	844	n/a
1990	1,421	2.5%	517	2.6%	837	-0.8%
1991	1,508	6.1%	529	2.3%	851	1.7%
1992	1,466	-2.8%	460	-13.0%	888	4.3%
1993	1,476	0.7%	502	9.1%	908	2.3%
1994	1,460	-1.1%	499	-0.6%	902	-0.7%
1995	1,425	-2.4%	558	11.8%	907	0.6%
1996	1,396	-2.0%	630	12.9%	868	-4.3%
1997	1,414	1.3%	593	-5.9%	945	8.9%
1998[b]	1,310	-7.3%	565	-4.7%	1,093	15.6%
1999[b]	1,309	-0.1%	586	3.7%	1,076	-1.5%
2000[b]	1,300	-0.7%	597	1.9%	1,072	-0.4%
2001[b]	1,266	-2.6%	621	4.0%	1,064	-0.7%
Total Percent Change 1989-2001	***-8.7%***		***23.2%***		***26.1%***	
Average Annual Growth Rate	***-0.8%***		***1.8%***		***2.0%***	

[a] The Statistics of U.S. Business is derived from Census County Business Patterns data, and reports somewhat different numbers of firms and facilities than other Census data sources.

[b] Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

Source: U.S. SBA, 1989-2001.

The trend in the number of firms between 1989 and 2001 is similar to the number of facilities. The number of firms in the Inorganic Chemicals segment peaked in 1992 and has trended downward since. The Organic Chemicals segment showed more volatility before peaking in 1998 with 710 firms; since then, the number of firms has declined somewhat. The number of firms in the Plastics Material and Resins segment increased substantially between 1993 and 1996, from 284 to 403 firms, before decreasing in the next two years. Starting in 1999, the Plastics Material and Resins segment showed three years of positive growth in the number of firms.

Table B2B-5 on the following page shows the number of firms in the three profiled chemical segments between 1990 and 2001.

Table B2B-5: Number of Firms for Profiled Chemical Segments[a]

Year	Inorganic Chemicals		Plastics Material and Resins		Organic Chemicals	
	Number of Firms	Percent Change	Number of Firms	Percent Change	Number of Firms	Percent Change
1990	640	n/a	301	n/a	579	n/a
1991	678	5.9%	319	6.0%	584	0.9%
1992	699	3.1%	255	-20.1%	611	4.6%
1993	683	-2.3%	284	11.4%	648	6.1%
1994	677	-0.9%	295	3.9%	644	-0.6%
1995	657	-3.0%	343	16.3%	644	0.0%
1996	625	-4.9%	403	17.5%	596	-7.5%
1997	611	-2.2%	358	-11.2%	674	13.1%
1998[b]	618	1.1%	322	-10.1%	710	5.3%
1999[b]	609	-1.3%	337	4.7%	684	-3.6%
2000[b]	611	0.2%	352	4.5%	683	-0.1%
2001[b]	606	-0.8%	375	6.5%	692	1.3%
Total Percent Change 1990-2001	***-5.4%***		***24.6%***		***19.5%***	
Average Annual Growth Rate	***-0.5%***		***2.0%***		***1.6%***	

[a] The Statistics of U.S. Business is derived from Census County Business Patterns data, and reports somewhat different numbers of firms and facilities than other Census data sources.

[b] Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

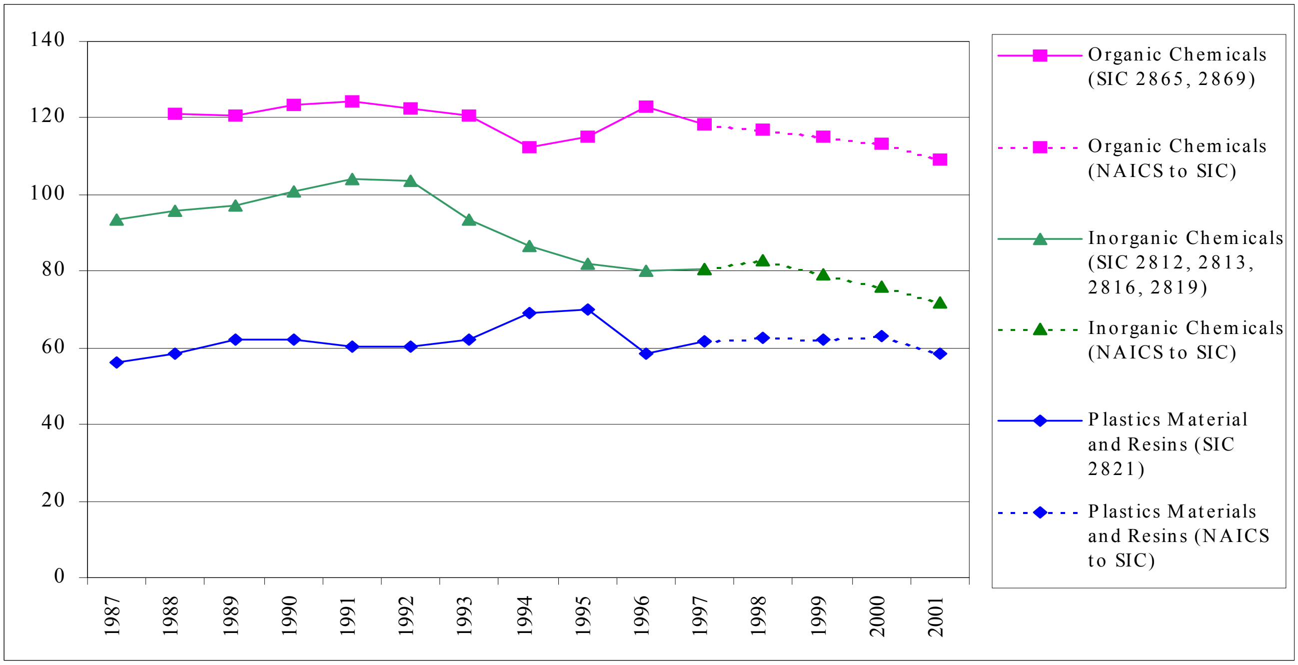
Source: U.S. SBA, 1989-2001.

B2B-2.4 Employment and Productivity

Figure B2B-3 below provides information on ***employment*** from the Annual Survey of Manufactures. With the exception of minor short-lived fluctuations, employment in the Organic Chemicals and Plastics Material and Resins segments remained relatively stable between 1988 and 2000 before seeing declines of greater than 4.5 percent in 2001. The Inorganic Chemicals segment, however, experienced a significant decrease in employment from 103,400 to 80,200 employees over the 1992 to 1996 period. This decrease reflects the industry's restructuring and downsizing efforts intended to reduce costs in response to competitive challenges. Employment in this segment remained fairly constant over the next two years before experiencing three years of employment declines greater than 4 percent through 2001. From 1987 to 2001, the Inorganic Chemicals segment had the largest overall decrease in employment at 23 percent. The Organic Chemicals segment employment declined 6.4 percent, while the Plastics Material and Resins segment was the only segment to increase employment, rising just over 4 percent for the period.

The chemical industry continued to experience more layoffs since 2001 as firms sought to improve financial performance by reducing employment costs. Both 2002 and 2003 saw workforce reductions, though not as severe as 2001, as firms shut plants or reduced operations (C&EN, 2003c).

Figure B2B-3: Employment for Profiled Chemical Segments[a] (000s)



[a]Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

Source: U.S. DOC, 1988-1991,1993-1996, and 1998-2001; U.S. DOC, 1987, 1992, and 1997.

Table B2B-6 presents the change in value added per labor hour, a measure of ***labor productivity***, for each of the profiled industry segments between 1988 and 2001. The trends in each segment show considerable volatility through the 1990s into the 2000s . The gains in productivity in the Inorganic Chemicals segment reflect firms' attempts to reduce costs by restructuring production and materials handling processes in response to maturing domestic markets and increased global competition (S&P, 2001). Over the 1988 to 2001 period, two segments, Plastics Material and Resins and Organic Chemicals, saw decreases of 15 and 31 percent, respectively, to value added per labor hour. The Inorganic Chemicals segment, however, improved 10 percent over the same timeframe.

Table B2B-6: Productivity Trends for Profiled Chemical Segments ($2003)

Year	Inorganic Chemicals				Plastics Material and Resins				Organic Chemicals			
	Value Added (mill.)	Prod. Hours (mill.)	Value Added/Hour ($/hr.)	Value Added/Hour Percent Change	Value Added (mill.)	Prod. Hours (mill.)	Value Added/Hour ($/hr.)	Value Added/Hour Percent Change	Value Added (mill.)	Prod. Hours (mill.)	Value Added/Hour ($/hr.)	Value Added/Hour Percent Change
1988	17,923	114	158		18,420	80	231		37,268	152	246	
1989	19,366	109	178	13%	17,472	84	209	-10%	39,128	155	253	3%
1990	20,848	115	182	2%	15,792	83	191	-8%	36,869	156	237	-7%
1991	19,673	121	163	-11%	13,778	81	171	-11%	32,628	156	209	-12%
1992	20,437	120	170	4%	15,281	79	195	14%	31,609	155	203	-3%
1993	18,974	108	176	3%	14,289	81	177	-9%	31,542	156	202	-1%
1994	17,626	101	175	-1%	17,914	89	200	13%	34,066	146	234	16%
1995	18,667	100	186	7%	20,195	92	221	10%	38,820	148	263	12%
1996	18,650	97	193	3%	17,235	81	214	-3%	32,022	158	203	-23%
1997	19,204	91	211	9%	19,517	84	234	9%	39,181	150	261	29%
1998[a]	25,247	92	276	31%	20,886	83	251	8%	31,727	147	216	-17%
1999[a]	18,097	88	206	-25%	20,075	84	238	-5%	32,776	143	230	6%
2000[a]	15,042	94	161	-22%	19,397	87	223	-6%	32,973	138	238	4%
2001[a]	15,112	87	173	8%	15,639	80	196	-12%	22,768	134	169	-29%
Total Percent Change 1988-2001	***-16%***	***-23%***	***10%***		***-15%***	***0%***	***-15%***		***-39%***	***-11%***	***-31%***	
Average Annual Percent Change	***-1%***	***-2%***	***1%***		***-1%***	***0%***	***-1%***		***-4%***	***-1%***	***-3%***	

[a] Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

Source: U.S. DOC, 1988-1991, 1993-1996, and 1998-2001; U.S. DOC, 1987, 1992, and 1997.

B2B-2.5 Capital Expenditures

The chemicals industry is relatively capital-intensive. According to the Census's *2001 Annual Survey of Manufactures*, facilities in NAICS 325, which includes all the profiled chemical SIC codes, had aggregate capital spending of almost $19 billion in 2001. Capital-intensive industries are characterized by large, technologically complex manufacturing facilities which reflect the economies of scale required to manufacture products efficiently. ***New capital expenditures*** are needed to extensively modernize, expand, and replace existing capacity to meet growing demand. All three profiled chemical industry segments experienced substantial increases in capital expenditures through the 1990s. Table B2B-7 on the following page shows that capital expenditures in the Inorganic Chemicals segment increased, in real terms, from $1.146 billion in 1987 to $2.642

billion in 1998. Although the following three years saw declines in capital expenditures, the Inorganic Chemicals segment increased capital expenditures by 80 percent from 1987 to 2001. The Plastics segment more than doubled its capital expenditures from 1987 through 1999, before significant reductions occurred in the subsequent two years. The Organic Chemicals segment peaked in 1996, and has seen its capital expenditures declining since, particularly in 2000 and 2001, for an overall decline of almost 18 percent from 1988 to 2001. Much of the growth in capital expenditures was driven by investment in capacity expansions to meet the increase in global demand for chemical products. Domestically, the continued substitution of synthetic materials for other basic materials and rising living standards caused consistent growth in the demand for chemical commodities (S&P, 2001). As the economy slowed in 2000, chemical industry firms curtailed capital expenditures in the face of weakening financial performance. As the economy picked up steam, an early 2003 survey of 19 chemical companies found that businesses sought to start increasing capital projects in 2003 (C&EN, 2003b).

Table B2B-7: Capital Expenditures for Profiled Chemical Segments (in millions, $2003)

Year	Inorganic Chemicals		Plastics Material and Resins		Organic Chemicals	
	Capital Expenditures	Percent Change	Capital Expenditures	Percent Change	Capital Expenditures	Percent Change
1987	1,146		1,800			
1988	1,170	2.1%	2,241	24.5%	4,441	
1989	1,799	53.7%	2,644	18.0%	5,473	23.2%
1990	1,721	-4.3%	3,155	19.3%	6,618	20.9%
1991	1,722	0.1%	2,817	-10.7%	6,570	-0.7%
1992	1,900	10.4%	2,088	-25.9%	5,818	-11.4%
1993	1,410	-25.8%	2,302	10.3%	4,815	-17.2%
1994	1,527	8.3%	2,968	28.9%	4,107	-14.7%
1995	1,959	28.3%	2,666	-10.2%	5,610	36.6%
1996	2,254	15.0%	3,134	17.6%	7,027	25.3%
1997	2,211	-1.9%	3,238	3.3%	6,438	-8.4%
1998[a]	2,642	19.5%	3,757	16.0%	5,470	-15.0%
1999[a]	2,236	-15.3%	4,039	7.5%	5,033	-8.0%
2000[a]	2,186	-2.2%	2,371	-41.3%	4,834	-4.0%
2001[a]	2,067	-5.4%	1,812	-23.6%	3,687	-23.7%
Total Percent Change 1987-2001	***80.4%***		***0.6%***		***-17.0%***	
Average Annual Growth Rate	***4.3%***		***0.0%***		***-1.4%***	

[a] Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

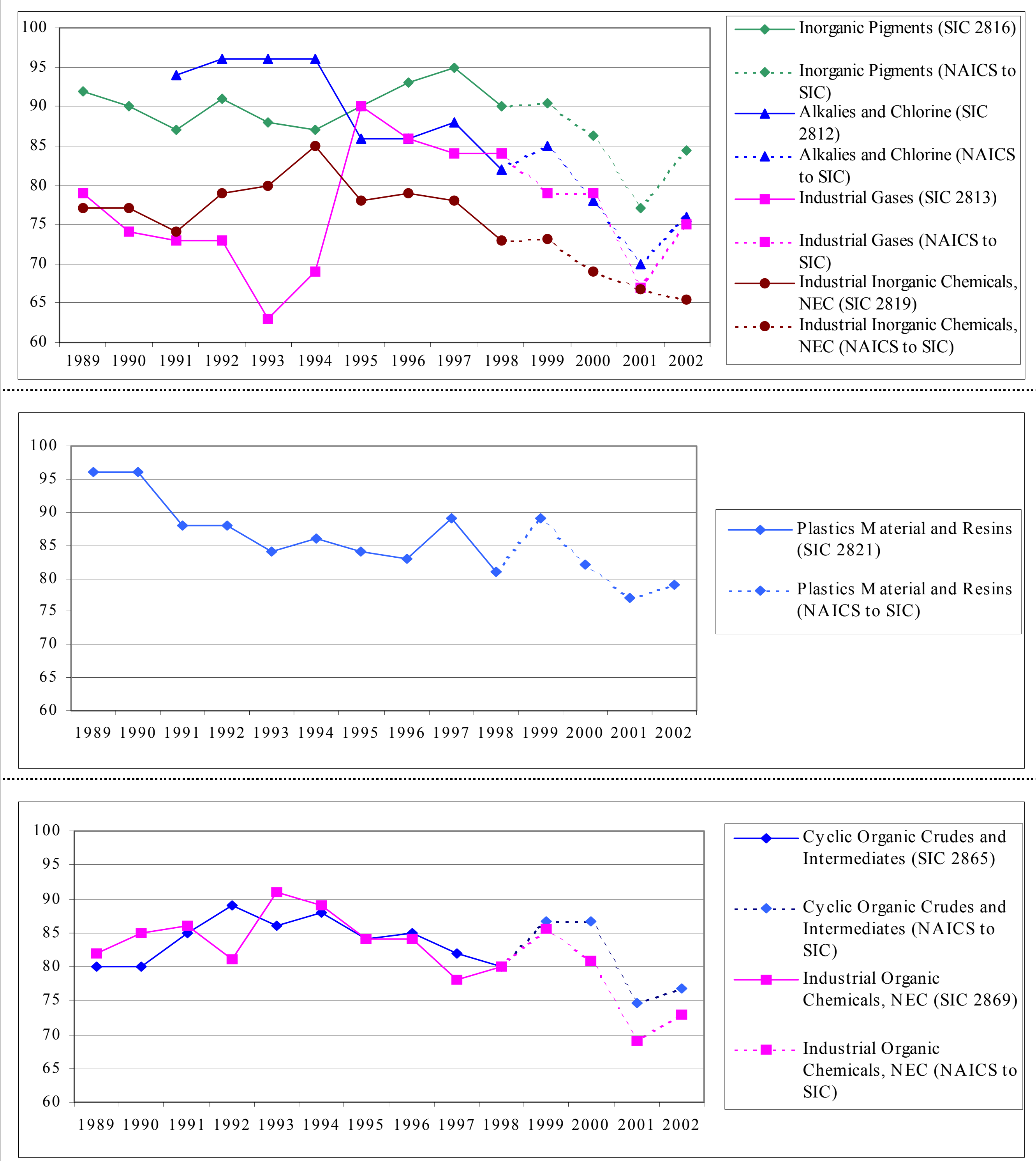
Source: U.S. DOC, 1988-1991, 1993-1996, and 1998-2001; U.S. DOC, 1987, 1992, and 1997.

B2B-2.6 Capacity Utilization

Capacity utilization measures actual output as a percentage of total potential output given the available capacity. Capacity utilization reflects excess or insufficient capacity in an industry and is an indication of whether new investment is likely. To take advantage of economies of scale, chemical commodities are typically produced in large facilities. Capacity additions in this industry are often made on a relatively large scale and can substantially affect the industry's capacity utilization rates. Figure B2B-4 presents the capacity utilization index from 1989 to 2002 for specific 4-digit SIC codes within each of the profiled segments in the chemicals industry. Capacity utilization in the Organic Chemicals segment remained the most stable through this time period with only moderate fluctuations between 1989 and 1999, followed by decreased utilization rates in 2000 and 2001, before rebounding in 2002. Plastics Material and Resins capacity utilization showed a downward trend, as the production of many commodity resins shifted overseas. U.S. producers responded by emphasizing the manufacture of speciality and higher-value-added products and by rationalizing capacity to improve profitability (McGraw-Hill, 2000).

Overall, the Inorganic Chemicals segment demonstrated the most volatility in capacity utilization between 1989 and 2002. The chlor-alkali industry (SIC code 2812) experienced an almost consistent decline in capacity utilization since its high of 96 percent from 1992 through 1994. This decrease reflects the enactment of treaties and legislation designed to reduce the emission of chlorinated compounds into the environment. These regulations decreased the demand for chlorine which, together with caustic soda, accounts for more than 75 percent of production by this segment. The significant increase in capacity utilization in the industrial gases segment (SIC code 2813) in the mid 1990s reflects the expansion of key intermediate purchasers of chemical commodities such as the primary metals and electronics industries. As these markets and the economy in general started to slow, utilization rates declined as well. Similarly, capacity utilization in the pigments and other inorganic chemicals segments (SIC codes 2816 and 2819) remained relatively stable between 1989 and 1998, before dropping in the early 2000s. The stability in these segments through 1999 reflects the fact that these are essentially mature markets where the demand for products tends to track growth in gross domestic product (GDP) (McGraw-Hill 2000). As the economy continued its sluggish performance in the early 2000s, utilization within this segment dampened, as demand for product decreased.

Figure B2B-4: Capacity Utilization Rates (Fourth Quarter) for Profiled Chemical Segments



[a] Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

Source: U.S. DOC, 1989-2002.

B2B-3 STRUCTURE AND COMPETITIVENESS

The chemicals industry continues to restructure and reduce costs in response to competitive challenges, including global oversupply for commodities. In the early 1990s, the chemical industry's cost-cutting came largely from restructuring and downsizing. The industry has taken steps to improve productivity, and consolidated to cut costs. Companies seeking growth within these relatively mature industry segments have made acquisitions to achieve production or marketing efficiencies. The Plastics Material and Resins segment, for example, experienced sizable consolidations in the late 1990s into 2000 (S&P, 2001).

B2B-3.1 Geographic Distribution

Chemical manufacturing facilities are located in every state, but almost two-thirds of U.S. chemical production is concentrated in ten states. Given the low value of many commodity chemicals and the handling problems posed by products such as industrial gases, nearly two-thirds of the tonnage shipped was transported less than 250 miles in 1998 (S&P, 2001).

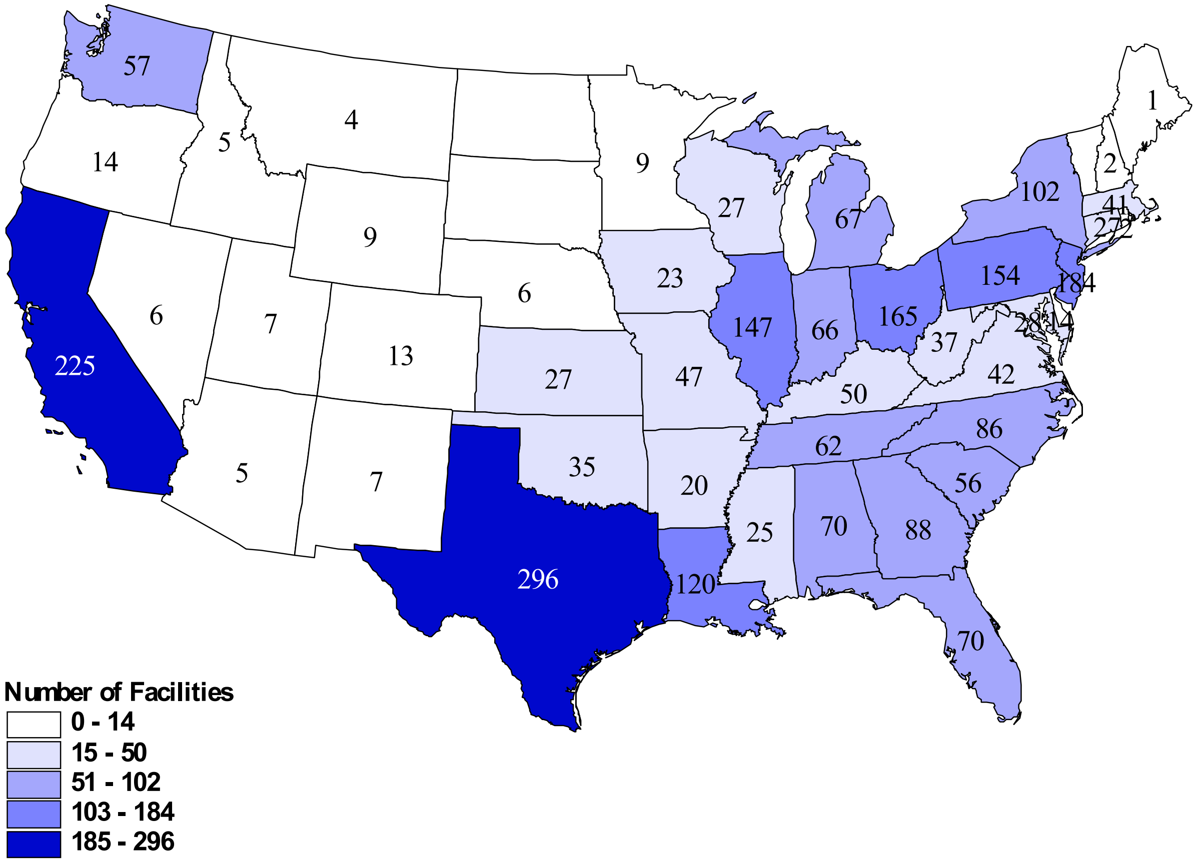
Facilities producing cyclic crudes and intermediates (SIC 2865) and unclassified industrial organic chemicals, not elsewhere classified (SIC 2869), are concentrated in Texas, New Jersey, Ohio, California, New York, and Illinois. Facility sites are typically chosen for their access to raw materials such as petroleum and coal products and to transportation routes. In addition, since much of the market for organic chemicals is the chemical industry, facilities tend to cluster near such end-users (U.S. EPA, 1995a).

Inorganic Chemicals facilities are typically located near consumers and, to a lesser extent, raw materials. The largest use of inorganic chemicals is in industrial processes for the manufacture of chemicals and nonchemical products. Facilities are therefore concentrated in the heavy industrial regions along the Gulf Coast, both East and West coasts, and the Great Lakes region. Since a large portion of inorganic chemicals are used by the organic chemicals manufacturing segment, the geographical distribution of Inorganic Chemicals facilities is very similar to that of Organic Chemicals facilities (U.S. EPA, 1995b). Facilities in the Plastics Material and Resins segment are concentrated in the heavy industrial regions, similar to both the Organic Chemicals and Inorganic Chemicals facilities.

Figure B2B-5 shows the distribution of all facilities by State in the profiled chemical segments, based on the 1992 Census of Manufactures.[2]

[2] The *1992 Census of Manufactures* is the most recent data available by SIC code and State.

Figure B2B-5: Number of Chemical Facilities by State for Profiled Chemical Segments



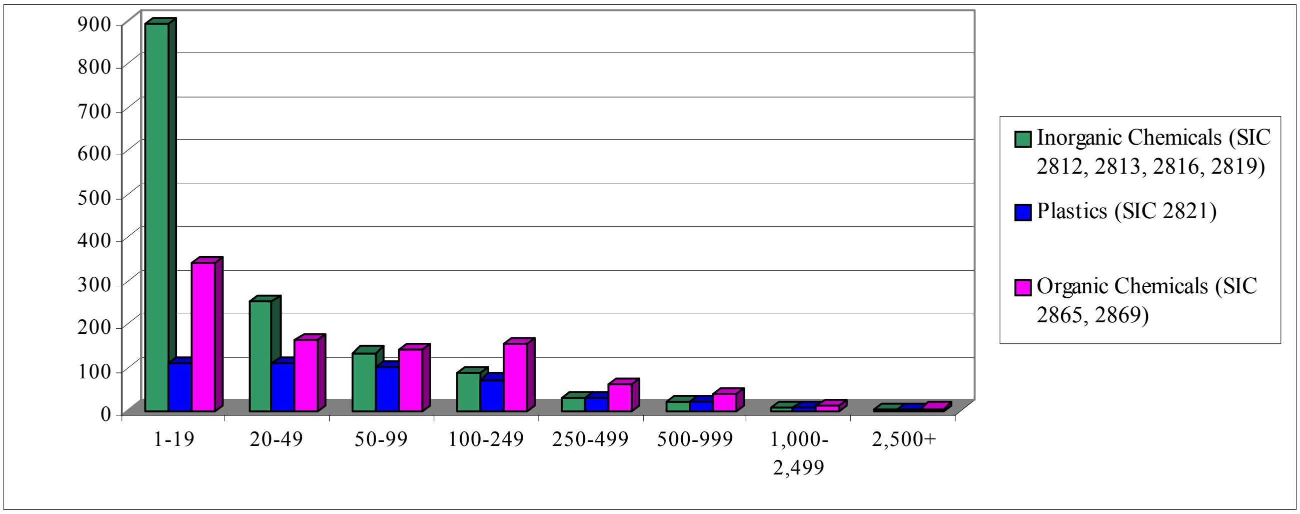
Source: *U.S. DOC, 1987, 1992, and 1997.*

B2B-3.2 Facility Size

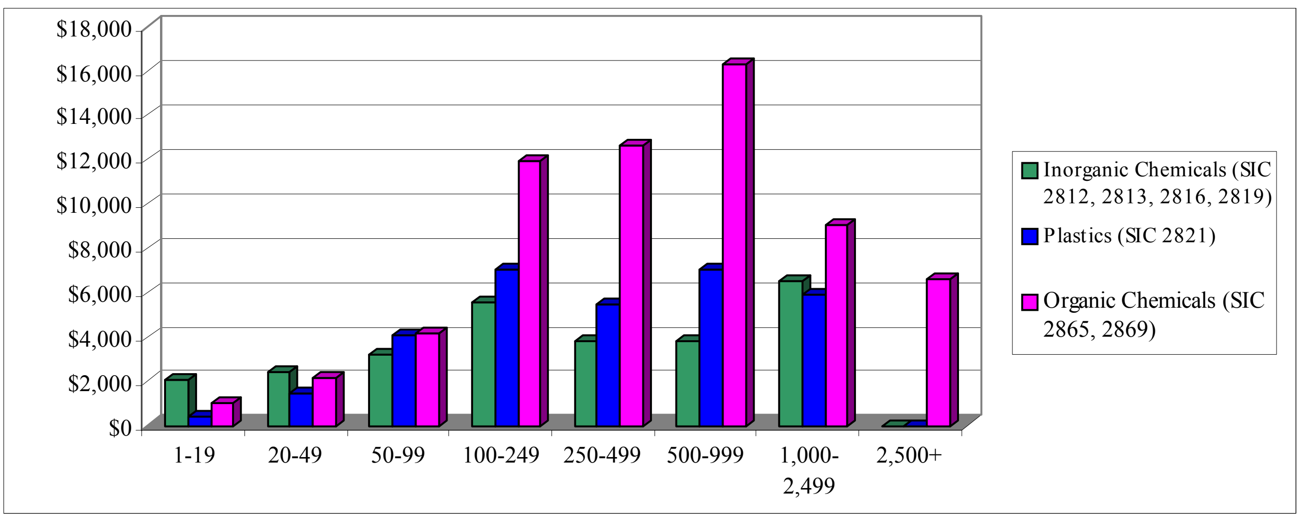
Facility size can be expressed by the number of employees and/or by the total value of shipments, with the most accurate depiction of size being a combination of both. The three profiled chemicals industry segments are characterized by a large number of small facilities, with more than 67 percent of facilities employing fewer than 50 employees and only eight percent employing 250 or more employees. However, the larger facilities in the three segments account for the majority of the industries' output. This fact is most pronounced in the Inorganic Chemicals segment where facilities with fewer than 20 employees account for 63 percent of all facilities but for only 8 percent of the industry's value of shipments. In the Organic Chemicals segment, approximately 29 percent of all facilities employ 100 employees or more. These facilities account for about 87 percent of the value of shipments for the industry. Similarly, facilities in the Plastics Material and Resins segment with more than 100 employees account for only 29 percent of all facilities but for 80 percent of the industry's value of shipments (see Figure B2B-6 below).

Figure B2B-6: Number of Facilities and Value Added by Employment Size Category in 1992[a] for Profiled Chemical Segments

Number of Facilities



Value of Shipments (in millions)



[a] The *1992 Census of Manufactures* is the most recent data available by SIC code and facility employment size.

Source: U.S. DOC, 1987, 1992, and 1997.

B2B-3.3 Firm Size

The Small Business Administration (SBA) defines small firms in the chemical industries according to the firm's number of employees. Firms in the Inorganic Chemicals segment (SIC codes 2812, 2813, 2816, 2819) and in Industrial Organic Chemicals, NEC (SIC code 2869) are defined as small if they have 1,000 or fewer employees; firms in Plastics Material and Resins (SIC 2821) and Cyclic Organic Crudes and Intermediates (SIC code 2865) are defined as small if they have 750 or fewer employees. The size categories reported in the Statistics of U.S. Businesses (SUSB) do not correspond with the SBA size classifications, therefore preventing precise use of the SBA size threshold in conjunction with SUSB data.

The SUSB data presented in Table B2B-8 show that in 2001, 481 of 606 firms in the Inorganic Chemicals segment had less than 500 employees. Therefore, at least 79 percent of firms in this segment were classified as small. These small firms owned 555 facilities, or 44 percent of all facilities in the segment. In the Plastics and Resins Industry segment, 299 of 375 firms, or 80 percent, had less than 500 employees in 2001. These small firms owned 330 of 621 facilities (53 percent) in the segment. In the Organic Chemicals segment, 74 percent of facilities (512 of 692) had fewer than 500 employees, owning 52 percent of all facilities in that segment.

Table B2B-8 below shows the distribution of firms, facilities, and receipts in the Inorganic Chemicals, Plastics Material and Resins, and Organic Chemicals segments by the employment size of the parent firm.

Table B2B-8: Number of Firms, Facilities and Estimated Receipts by Firm Size Category for Profiled Chemical Segments (2001)

Employment Size Category	Inorganic Chemicals		Plastics Material and Resins		Organic Chemicals	
	No. of Firms	Number of Facilities	No. of Firms	Number of Facilities	No. of Firms	Number of Facilities
0-19	288	290	156	156	277	278
20-99	129	162	97	101	156	168
100-499	64	103	46	73	79	111
500+	125	711	76	291	180	507
Total	***606***	***1,266***	***375***	***621***	***692***	***1,064***

[a] Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

Source: U.S. SBA, 1989-2001.

B2B-3.4 Concentration Ratios

Concentration is the degree to which industry output is concentrated in a few large firms. Concentration is closely related to entry barriers with more concentrated industries generally having higher barriers.

The four-firm ***concentration ratio*** (CR4) and the ***Herfindahl-Hirschman Index*** (HHI) are common measures of industry concentration. The CR4 indicates the market share of the four largest firms. For example, a CR4 of 72 percent means that the four largest firms in the industry account for 72 percent of the industry's total value of shipments. The higher the concentration ratio, the less competition there is in the industry, other things being equal[3]. An industry with a CR4 of more than 50 percent is generally considered concentrated. The HHI indicates concentration based on the largest 50 firms in the industry. It is equal to the sum of the squares of the market shares for the largest 50 firms in the industry. For example, if an industry consists of only three firms with market shares of 60, 30, and 10 percent, respectively, the HHI of this industry would be equal to 4,600 (602 + 302 + 102). The higher the index, the fewer the number of firms supplying the industry and the more concentrated the industry. Based on the U.S. Department of Justice's guidelines for evaluating mergers, markets in which the HHI

[3]Note that the measured concentration ratio and the HHF are very sensitive to how the industry is defined. An industry with a high concentration in domestic production may nonetheless be subject to significant competitive pressures if it competes with foreign producers or if it competes with products produced by other industries (e.g., plastics vs. aluminum in beverage containers). Concentration ratios based on share of domestic production are therefore only one indicator of the extent of competition in an industry.

is under 1000 are considered unconcentrated, markets in which the HHI is between 1000 and 1800 are considered to be moderately concentrated, and those in which the HHI is in excess of 1800 are considered to be concentrated.

Of the profiled chemicals and allied products segments, as shown in Table B2B-9, only Alkalies and Chlorine (SIC 2812), Industrial Gases (SIC 2813), and Inorganic Pigments (SIC 2816) would be considered concentrated based on their CR4 and HHI values. In contrast, Industrial Inorganic Chemicals, NEC (SIC 2819), Plastics Material and Resins (SIC 2821), Cyclic Crudes and Intermediates (SIC 2865), and Industrial Organic Chemicals, NEC (SIC 2869) would be considered competitive. The diversity of products in some of the profiled segments, however, makes generalizations about concentration less reliable than in industries with a more limited product slate. That is, within a single SIC code, the numbers of producers may vary substantially by individual product – firms may possess relatively high market power in products with a smaller number of competing producers even though the total SIC code would appear to have a relatively low concentration. On the basis of concentration information, some industry segments would therefore appear to be moderately concentrated; accordingly, firms in these segments might possess a moderate degree of market power and thus the ability to pass compliance costs through to customers as price increases. However, as discussed above and more specifically in the following section, competition from foreign producers in both domestic and export markets, increasingly restrains any discretionary pricing power of U.S. firms in the profiled industry segments.

Table B2B-9: Selected Ratios for Four-Digit SIC Codes for Profiled Chemical Segments, 1987 and 1992[a]

SIC Code	Year	Concentration Ratios				
		4 Firm (CR4)	8 Firm (CR8)	20 Firm (CR20)	50 Firm (CR50)	Herfindahl-Hirschman Index
Inorganic Chemicals						
2812	1987	72%	93%	99%	100%	2,328
	1992	75%	90%	99%	100%	1,994
2813	1987	77%	88%	95%	98%	1,538
	1992	78%	91%	96%	99%	1,629
2816	1987	64%	76%	94%	99%	1,550
	1992	69%	79%	93%	99%	1,910
2819	1987	38%	49%	68%	84%	468
	1992	39%	50%	68%	85%	677
Plastics Material and Resins						
2821	1987	20%	33%	61%	89%	248
	1992	24%	39%	63%	90%	284
Organic Chemicals						
2865	1987	34%	50%	77%	96%	542
	1992	31%	45%	72%	94%	428
2869	1987	31%	48%	68%	86%	376
	1992	29%	43%	67%	86%	336

[a] The *1992 Census of Manufactures* is the most recent concentration ratio data available by SIC code.

Source: U.S. DOC, 1987, 1992, and 1997.

B2B-3.5 Foreign Trade

The chemicals industry is the largest exporter in the United States. The industry generates more than 10 percent of the nation's total exports, and overseas sales constitute a growing share of U.S. chemical company revenues. The major U.S. producers still derive 50 percent or more of their revenue from domestic sales, however (S&P, 2001).

This profile uses two measures of foreign competition: ***export dependence*** and ***import penetration***.

Import penetration measures the extent to which domestic firms are exposed to foreign competition in domestic markets. Import penetration is calculated as total imports divided by total value of domestic consumption in that industry: where domestic consumption equals domestic production plus imports minus exports. Theory suggests that higher import penetration levels will reduce market power and pricing discretion because foreign competition limits domestic firms' ability to exercise such power. Firms belonging to segments in which imports account for a relatively large share of domestic sales would therefore be at a relative disadvantage in their ability to pass-through costs because foreign producers would not incur costs as a result of the Phase III regulation. The estimated import penetration ratio for the entire U.S. manufacturing sector (NAICS 31-33) for 2001 is 22 percent. For characterizing the ability of industries to withstand compliance cost burdens, EPA judges that industries with import ratios close to or above 22 percent would more likely face stiff competition from foreign firms and thus be less likely to succeed in passing compliance costs through to customers.

Export dependence, calculated as exports divided by value of shipments, measures the share of a segment's sales that is presumed subject to strong foreign competition in export markets. The Phase III regulation would not increase the production costs of foreign producers with whom domestic firms must compete in export markets. As a result, firms in industries that rely to a greater extent on export sales would have less latitude in increasing prices to recover cost increases resulting from regulation-induced increases in production costs. The estimated export dependence ratio for the entire U.S. manufacturing sector for 2001 is 15 percent. For characterizing the ability of industries to withstand compliance cost burdens, EPA judges that industries with export ratios close to or above 15 percent are at a relatively greater disadvantage in potentially recovering compliance costs through price increases since export sales are presumed subject to substantial competition from foreign producers.

Table B2B-10 presents trade statistics for each of the profiled chemical segments. Both export dependence and import penetration experienced increases in each of these segments between 1989 and 2001.

Globalization of markets has become a key factor in the Inorganic Chemicals segment, with both import penetration and export dependence growing substantially over the 13-year analysis period. During this period, imports rose by almost 12 percent, while exports has climbed 5 percent. The greater growth in imports underscores the increasing competition from foreign producers in domestic markets.

Increased globalization has also affected the Plastics Material and Resins segment. Imports and exports of plastics and resins have increased significantly over the time period, reflecting the continued growth in the global market. Of the three profiled chemical segments, this segment has shown the largest overall increases in values of imports and exports with total growth of 177 percent and 65 percent, respectively, from 1989 through 2001. Import penetration grew more quickly than export dependence in this segment due to declining export opportunities and increased competition from new foreign capacity. The United States remained a net exporter of plastics and resins, despite these trends. The market for organic chemicals, particularly petrochemicals, has become increasingly competitive. Significant capacity expansions for petrochemicals worldwide increased competition in domestic markets from imports and began to limit export opportunities for U.S. producers. Through 1999, the segment still exported more than it imported. This balance recently changed though as imports exceeded exports in both 2000 and 2001. From 1989 through 2001, imports in this segment grew by 165 percent, while export growth was at 43 percent.

In 2001, the Inorganic Chemicals segment's import penetration ratio was 26.9 percent, while the Organic Chemicals segment's import penetration ratio was slightly lower at 25.9 percent. Both segments likely face strong competition from foreign firms in U.S. markets. The Plastics Material and Resins segment had an import penetration ratio of 14.3 percent in 2001, suggesting this segment does not presently face strong competition from foreign firms' presence in U.S. markets. However, the import penetration ratio nearly doubled in the decade from 1991 to 2001, which could indicate that foreign firms have begun aggressive pursuit of these U.S. markets. In 2001, the export dependence ratio was 28.2 percent for the Inorganic Chemicals segment, 26.1 percent for the Plastics Material and Resins segment, and 24.2 percent for the Organic Chemicals segment. All three segments likely face significant competitive pressure in retaining these positions in export markets. Given these levels of exposure to competition from foreign firms in domestic and export markets, the profiled chemicals industry segments likely have little discretionary power to recover compliance costs through price increases.

Recent trends in international chemicals markets imply that U.S. producers will continue to face strong competition from foreign producers. The industry's trade balance declined in 2000, due to increased imports from Western Europe, encouraged by the strong U.S. dollar relative to the Euro, and growth in the petrochemical industry in the Middle East. Declines in the dollar relative to the Euro improved export performance somewhat, but decline in the global economy resulted in mixed trade performance in 2001 (Chemical Market Reporter, 2001). In 2002, the chemical industry's traditional trade surplus reversed, reaching a deficit of around \$4 billion (C&EN, 2003a). After nine months of 2003, the deficit had ballooned to \$7.7 billion (C&EN, 2003c).

Table B2B-10: Trade Statistics for Profiled Chemical Segments

Year	Value of imports (millions, $2003)	Value of exports (millions, $2003)	Value of shipments (millions, $2003)	Implied Domestic Consumption[a]	Import Penetration[b]	Export Dependence[c]
Inorganic Chemicals, Except Pigments						
1989	5,688	6,457	28,357	27,588	20.6%	22.8%
1990	5,599	6,037	30,414	29,976	18.7%	19.8%
1991	5,360	6,243	29,492	28,609	18.7%	21.2%
1992	5,095	6,274	29,416	28,237	18.0%	21.3%
1993	4,828	5,764	27,570	26,634	18.1%	20.9%
1994	5,510	6,104	25,373	24,779	22.2%	24.1%
1995	6,432	7,087	26,895	26,240	24.5%	26.4%
1996	7,036	7,174	27,323	27,185	25.9%	26.3%
1997	5,811	6,904	28,100	27,007	21.5%	24.6%
1998[d]	5,832	6,119	34,163	33,876	17.2%	17.9%
1999[d]	5,812	5,822	27,051	27,041	21.5%	21.5%
2000[d]	6,630	6,658	24,679	24,651	26.9%	27.0%
2001[d]	6,363	6,784	24,049	23,628	26.9%	28.2%
Total Percent Change 1989-2001	***11.9%***	***5.1%***		***-14.4%***		***23.9%***
Average Annual Growth Rate	***0.9%***	***0.7%***		***-1.6%***		***2.6%***
Plastics Material and Resins						
1989	2,089	7,424	44,728	39,393	5.3%	16.6%
1990	2,345	8,110	40,564	34,799	6.7%	20.0%
1991	2,221	9,237	36,991	29,975	7.4%	25.0%
1992	2,522	8,570	38,286	32,238	7.8%	22.4%
1993	3,010	8,584	37,710	32,136	9.4%	22.8%
1994	3,839	9,864	43,667	37,642	10.2%	22.6%
1995	4,685	11,857	49,844	42,672	11.0%	23.8%
1996	4,701	11,918	45,139	37,922	12.4%	26.4%
1997	4,866	12,024	50,079	42,921	11.3%	24.0%
1998[d]	4,948	11,252	49,314	43,010	11.5%	22.8%
1999[d]	5,210	11,268	50,230	44,172	11.8%	22.4%
2000[d]	6,090	13,093	55,167	48,164	12.6%	23.7%
2001[d]	5,791	12,258	46,924	40,457	14.3%	26.1%
Total Percent Change 1989-2001	***177.2%***	***65.1%***		***2.7%***		***57.4%***
Average Annual Growth Rate	***8.9%***	***3.3%***		***2.1%***		***1.4%***
Organic Chemicals, Except Gum & Wood						
1989	7,822	13,320	87,856	82,358	9.5%	15.2%

Table B2B-10: Trade Statistics for Profiled Chemical Segments

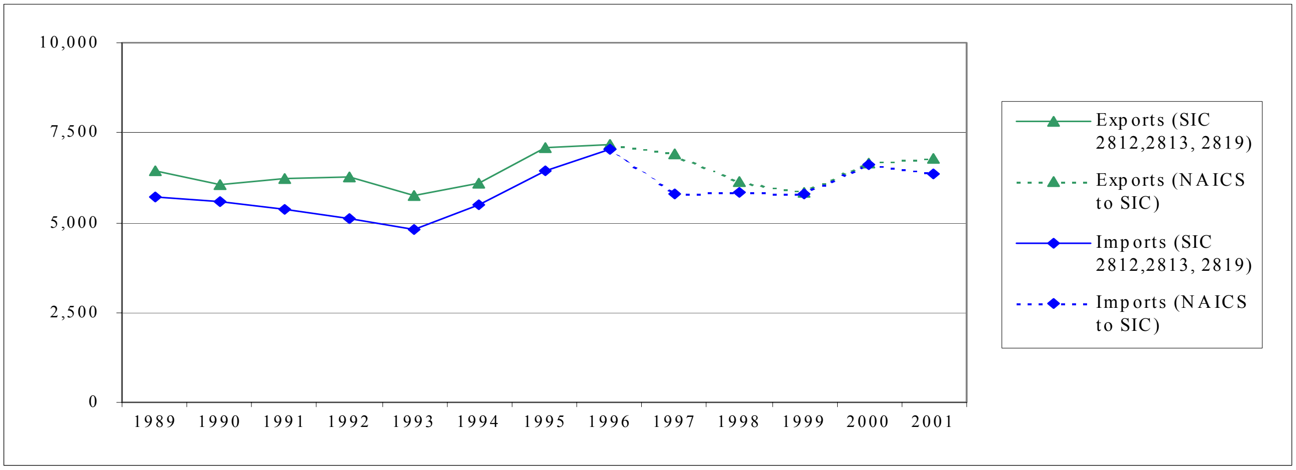
Year	Value of imports (millions, $2003)	Value of exports (millions, $2003)	Value of shipments (millions, $2003)	Implied Domestic Consumption[a]	Import Penetration[b]	Export Dependence[c]
1990	8,123	12,678	84,237	79,682	10.2%	15.1%
1991	8,239	12,670	79,725	75,294	10.9%	15.9%
1992	8,858	12,329	78,063	74,592	11.9%	15.8%
1993	8,765	12,494	75,958	72,229	12.1%	16.4%
1994	10,132	14,500	81,008	76,640	13.2%	17.9%
1995	12,121	17,916	87,077	81,282	14.9%	20.6%
1996	12,985	15,980	84,276	81,281	16.0%	19.0%
1997	17,312	20,079	91,683	88,916	19.5%	21.9%
1998[d]	16,683	18,159	77,134	75,658	22.1%	23.5%
1999[d]	18,049	18,885	82,553	81,717	22.1%	22.9%
2000[d]	22,151	21,221	92,222	93,152	23.8%	23.0%
2001[d]	20,728	19,032	78,489	80,185	25.9%	24.2%
Total Percent Change 1989-2001	***165.0%***	***42.9%***		***-2.6%***		***59.9%***
Average Annual Growth Rate	***8.5%***	***4.0%***		***0.7%***		***4.0%***

[a] Calculated by EPA as shipments + imports - exports.
[b] Calculated by EPA as imports divided by implied domestic consumption.
[c] Calculated by EPA as exports divided by shipments.
[d] Before 1998, data were compiled in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census Bridge Between NAICS and SIC.

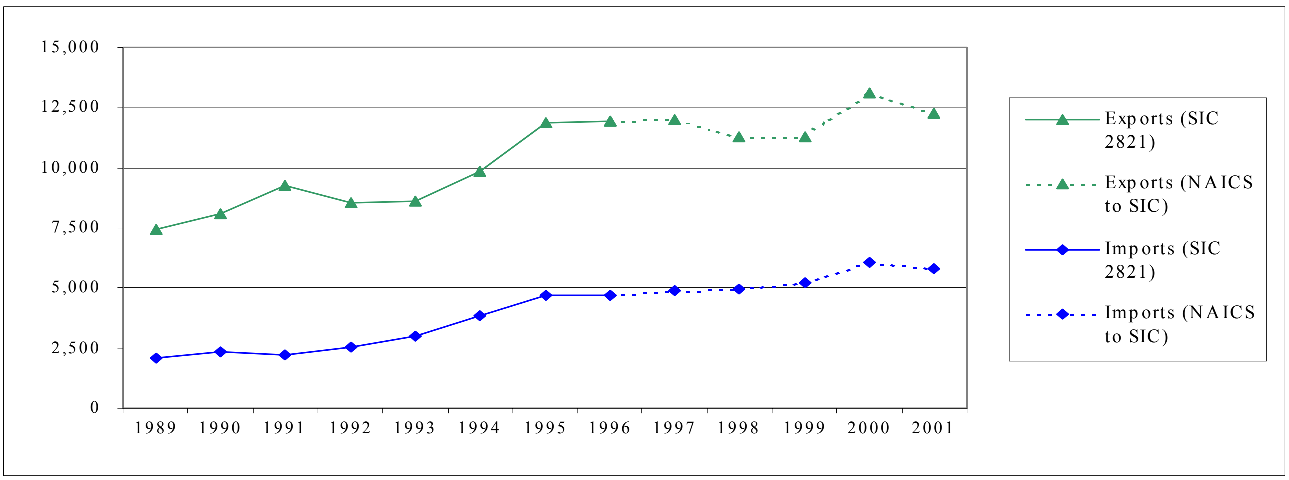
Source: U.S. DOC, 2001.

Figure B2B-7: Value of Imports and Exports for Profiled Chemical Segments (in millions,$2003)

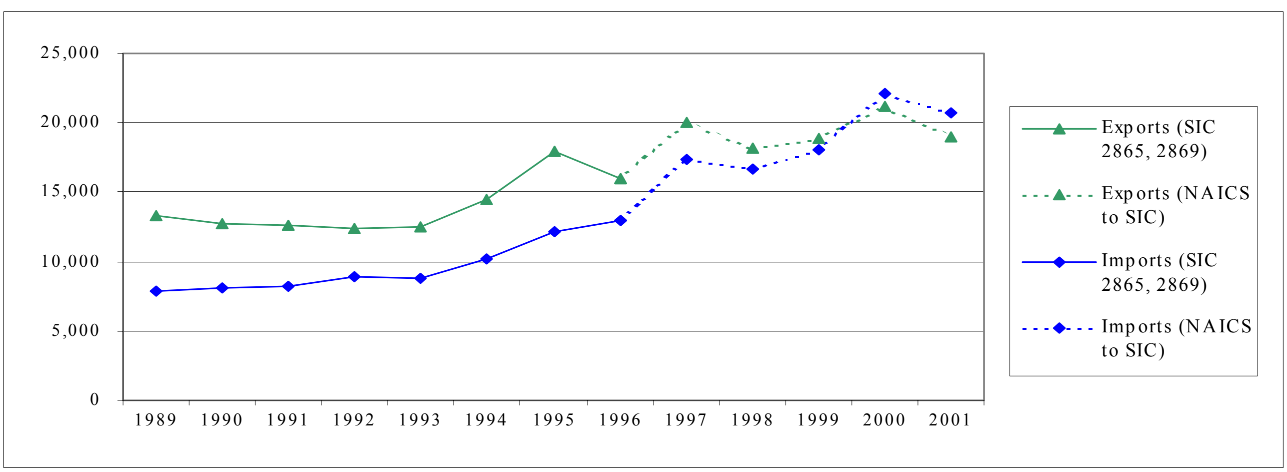
Inorganic Chemicals, Except Pigments



Plastics Material and Resins



Organic Chemicals, Except Gum & Wood



Source: U.S. DOC, 2001.

B2B-4 FINANCIAL CONDITION AND PERFORMANCE

The financial performance and condition of the chemical industry are important determinants of its ability to withstand the costs of regulatory compliance without material adverse economic/financial impact. To provide insight into the industry's financial performance and condition, EPA reviewed two key measures of financial performance over the 12-year period, 1992-2003: net profit margin and return on total capital. EPA calculated these measures as a revenue-weighted index of measure values for public reporting firms in the respective industries, using data from the Value Line Investment Survey. Financial performance in the most recent financial reporting period (2003) is obviously not a perfect indicator of conditions at the time of regulatory compliance. However, examining the trend, and deviation from the trend, through the most recent reporting period gives insight into where the industry *may be*, in terms of financial performance and condition, at the time of compliance. In addition, the volatility of performance against the trend, in itself, provides a measure of the *potential* risk faced by the industry in a future period in which compliance requirements are faced: all else equal, the more volatile the historical performance, the more likely the industry *may* be in a period of relatively weak financial conditions at the time of compliance.

Net profit margin is calculated as after-tax income before nonrecurring gains and losses as a percentage of sales or revenues, and measures profitability, as reflected in the conventional accounting concept of net income. Over time, the firms in an industry, and the industry collectively, must generate a sufficient positive profit margin if the industry is to remain economically viable and attract capital. Year-to-year fluctuations in profit margin stem from several factors, including: variations in aggregate economic conditions (including international and U.S. conditions), variations in industry-specific market conditions (e.g., short-term capacity expansion resulting in overcapacity), or changes in the pricing and availability of inputs to the industry's production processes (e.g., the cost of energy to the chemical process). The extent to which these fluctuations affect an industry's profitability, in turn, depends heavily on the fixed vs. variable cost structure of the industry's operations. In a capital intensive industry such as the chemical and allied products industry, the relatively high fixed capital costs as well as other fixed overhead outlays, can cause even small fluctuations in output or prices to have a large positive or negative affect on profit margin.

Return on total capital is calculated as annual net profit, plus one-half of annual long-term interest, divided by the total of shareholders' equity and long-term debt (total capital). This concept measures the total productivity of the capital deployed by a firm or industry, regardless of the financial source of the capital (i.e., equity, debt, or liability element). As such, the return on total capital provides insight into the profitability of a business' assets independent of financial structure and is thus a "purer" indicator of asset profitability than return on equity. In the same way as described for *net profit margin*, the firms in an industry, and the industry collectively, must generate over time a sufficient return on capital if the industry is to remain economically viable and attract capital. The factors causing short-term variation in *net profit margin* will also be the primary sources of short-term variation in *return on total capital*.

Figure B2B-8 presents net profit margin and return on total capital for public-reporting firms in two chemical industry segments – (1) Industrial Chemicals and (2) Plastics and Synthetic Fibers – for the 12-year period, 1992 and 2003. The Industrial Chemicals segment corresponds approximately to the Organic Chemicals and Inorganic Chemicals profiled industry segments; the Plastics and Synthetic Fibers segment corresponds approximately to the Plastics Material and Resins profiled industry segment. The financial performance information reported in Figure B2B-8 confirms the trends and performance discussed above in this section.

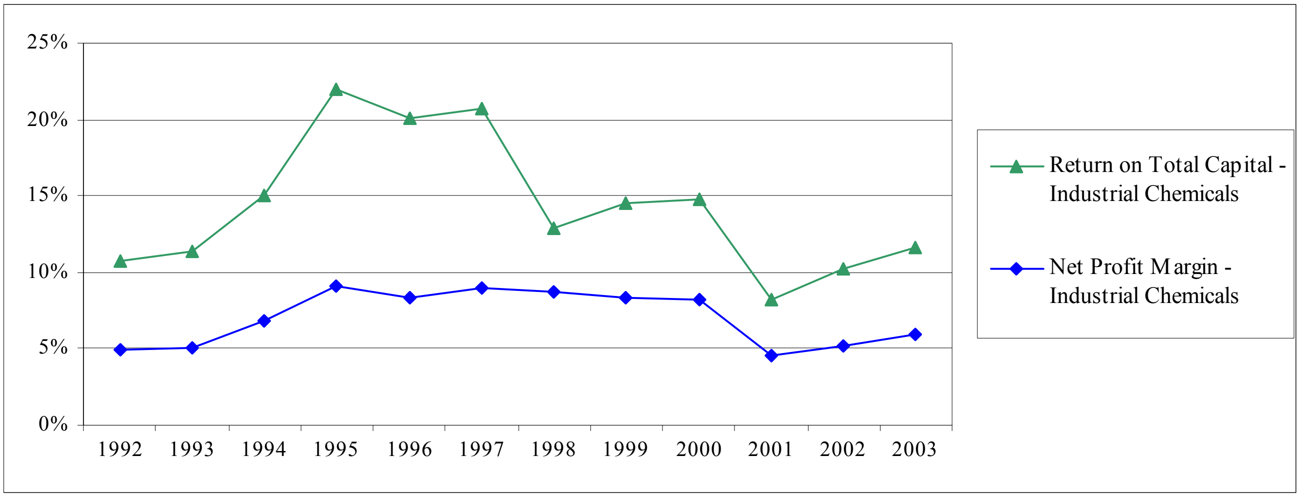
As shown in Figure B2B-8, the Industrial Chemicals (Organic Chemicals and Inorganic Chemicals) segment has seen moderate volatility of financial performance over the analysis period. Return on total capital moved off a post-recession low near 10 percent in 1992 to achieve levels in excess of 20 percent during 1995-1997. Recovery of demand accompanied by industry restructuring and downsizing accounted for the upturn in performance. During the latter part of the decade, though, increased competition from foreign producers and demand weakness in Asian markets eroded this performance. As a result, return on capital fell below 15 percent in 1998, and remained at this lower level through 2000. In 2001, a series of factors – high energy and raw material prices at the start of the year, and overcapacity, the terrorist attacks, and slowing U.S. and global economies at the end of the year – led to a further sharp decline in return on capital performance of approximately 8 percent. Return on total capital improved modestly during 2002 and 2003 but remained sub-par compared to mid 1990s performance. Net profit margin shows a similar, though less volatile, trend.

The same factors largely influenced performance in the Plastics and Synthetic Fibers (Plastics Material and Resins) segment over the 12 year period. Performance in this segment followed a similar, but less volatile, pattern to that of the Industrial Chemicals segment. Return on total capital rose from a low near 10 percent in 1993 to a period high of 15 percent in 1995. Since then, performance trended down to reach a period low of approximately 9 percent in 2001. This segment achieved modest improvement in 2002 and 2003. Net profit margin again shows a similar, though less volatile, trend compared to return on capital.

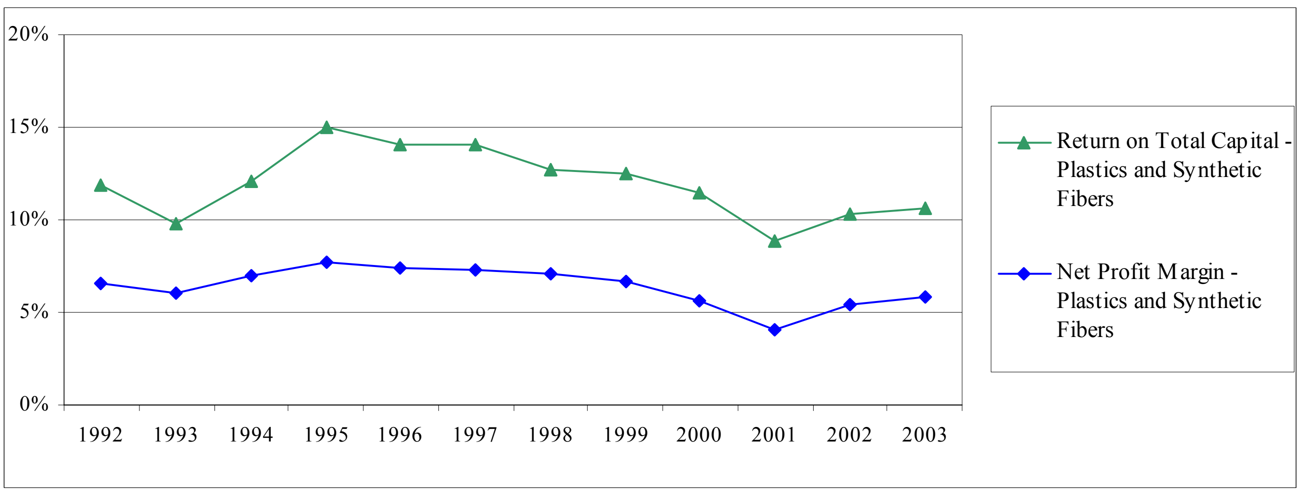
Overall, the profiled segments of the chemical industry remain at weaker levels of financial performance than achieved during the mid 1990s but appear to be recovering from the sharp weakness of 2001-2002. Continued recovery in 2004 and beyond suggest improved ability to withstand additional regulatory compliance costs without imposing significant financial impacts.

Figure B2B-8: Net Profit Margin and Return in Total Capital for the Chemical Industry

Industrial Chemicals (Organic and Inorganic)



Plastics and Synthetic Fibers



Source: Value Line, 1992-2003.

B2B-5 FACILITIES OPERATING COOLING WATER INTAKE STRUCTURES

Section 316(b) of the Clean Water Act applies to point source facilities that use or propose to use a cooling water intake structure that withdraws cooling water directly from a surface waterbody of the United States. In 1982, the chemical and allied products industry withdrew 2,797 billion gallons of cooling water, accounting for approximately 3.6 percent of total industrial cooling water intake in the United States[4]. The industry ranked 2nd in industrial cooling water use behind the electric power generation industry (1982 Census of Manufactures).

[4] Data on cooling water use are from the *1982 Census of Manufactures*. 1982 was the last year in which the Census of Manufactures reported cooling water use.

This section provides information for facilities in the profiled chemical and allied products segments potentially subject to the proposed regulation. Existing facilities that meet all of the following conditions are potentially subject to the proposed regulation:[5]

- 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;

- Have an National Pollutant Discharge Elimination System (NPDES) permit or are required to obtain one; and

- Have a design intake flow of greater than 2 million gallons per day (MGD).

The proposed Phase III regulation 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 section focuses on the estimated 144 facilities nationwide in the profiled chemical and allied products segments identified in EPA's 2000 Section 316(b) Industry Survey as being potentially subject to this proposed regulation[6]. Information collected in the Detailed Industry Questionnaire found that an estimated 64 out of 435 Inorganic Chemicals facilities (15 percent), 19 out of 305 Plastics Material and Resins facilities (6 percent), and 61 out of 423 Organic Chemicals facilities (14 percent) meet the characteristics of a potential Phase III facility.

B2B-5.1 Waterbody and Cooling System Type

Table B2B-11 shows the distribution of U.S. Phase III facilities in the profiled chemical segments by type of waterbody and cooling system. The table shows that most of the U.S. Phase III facilities either have a once-through system (62, or 50 percent) or employ a combination of a once through and a recirculating system (37, or 30 percent). The majority of existing facilities draw water from a freshwater stream or river (95, or 76 percent). Seven of the 20 facilities that withdraw from an estuary, the most sensitive type of waterbody, use a once-through cooling system. Plants with once-through cooling water systems withdraw between 70 and 98 percent more water than those with recirculating systems.

[5] The proposed Phase III regulation also applies to existing electric generating facilities as well as certain facilities in the oil and gas extraction industry and the seafood processing industry. See Chapters B4 and B5 and Part C of this document for more information on these industries.

[6] EPA applied sample weights to the sampled 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 B2B-11: Number of Potential Phase III facilities by Water Body and Cooling System Type for Profiled Chemical Segments

Water Body Type	Cooling System										
	Recirculating		Combination		Once-Through		Other		Unknown		Total[a]
	Number	% of Total	Number	% of Total	Number	% of Total	Number	% of Total	Number	% of Total	
Inorganic Chemicals											
Estuary/ Tidal River	0	0%	13	65%	7	35%	0	0%	0	0%	20
Ocean	0	0%	0	0%	9	100%	0	0%	0	0%	9
Freshwater Stream/ River	4	18%	0	0%	17	77%	0	0%	0	0%	22
Lake/ Reservoir	0	0%	4	100%	0	0%	0	0%	0	0%	4
Great Lake	0	0%	0	0%	4	44%	4	44%	0	0%	9
Total[a]	***4***	***6%***	***17***	***27%***	***37***	***58%***	***4***	***6%***	***0***	***0%***	***64***
Plastics Material and Resins											
Freshwater Stream/ River	0	0%	9	50%	4	22%	0	0%	4	22%	18
Lake/ Reservoir	0	0%	2	100%	0	0%	0	0%	0	0%	2
Total[a]	***0***	***0%***	***11***	***58%***	***4***	***21%***	***0***	***0%***	***4***	***21%***	***19***
Organic Chemicals											
Freshwater Stream/ River	9	16%	9	16%	30	53%	9	16%	0	0%	57
Great Lake	0	0%	0	0%	4	100%	0	0%	0	0%	4
Total[a]	***9***	***15%***	***9***	***15%***	***35***	***57%***	***9***	***15%***	***0***	***0%***	***61***
Total for Profiled Chemical Facilities											
Estuary/ Tidal River	0	0%	13	65%	7	35%	0	0%	0	0%	20
Ocean	0	0%	0	0%	9	100%	0	0%	0	0%	9
Freshwater Stream/ River	13	14%	18	19%	52	54%	9	9%	4	4%	96
Lake/ Reservoir	0	0%	6	100%	0	0%	0	0%	0	0%	6
Great Lake	0	0%	0	0%	9	69%	4	31%	0	0%	13
Total[a]	***13***	***9%***	***37***	***26%***	***76***	***53%***	***13***	***9%***	***4***	***3%***	***144***

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

Source: U.S. EPA, 2000.

B2B-5.2 Facility Size

The 316(b) sample facilities are generally larger than facilities in the chemicals industry as a whole, as reported in the Census and discussed previously:

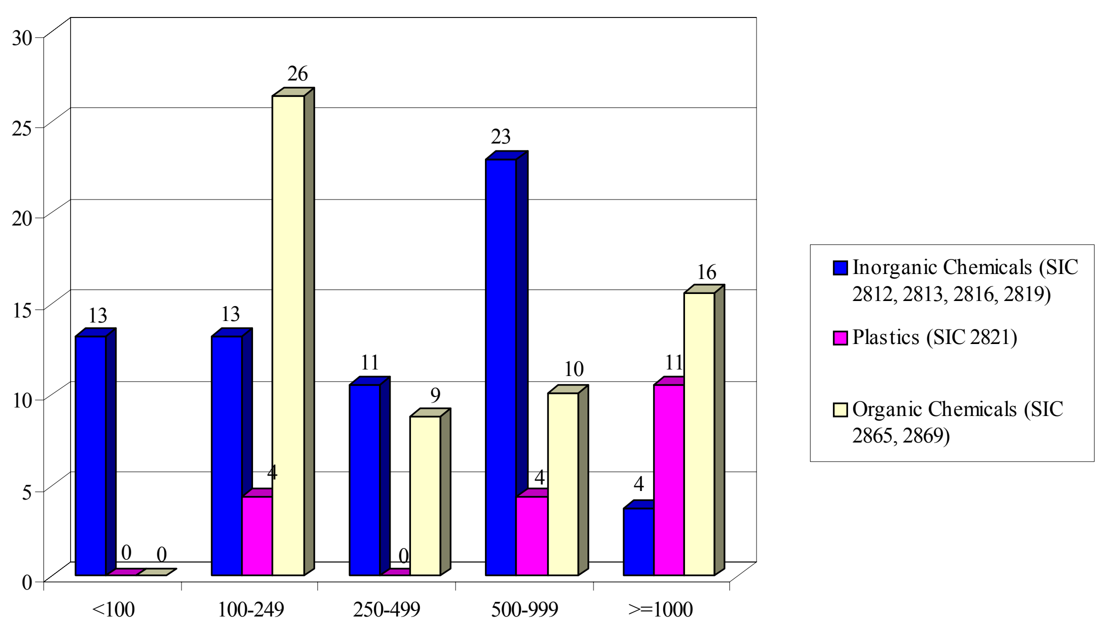
- Ninety-eight percent of all facilities in the Inorganic Chemicals segment had fewer than 100 employees in 1992, compared with 21 percent of the potential Phase III facilities.

- Ninety-four percent of all facilities in the Plastics Material and Resins segment had fewer than 100 employees in 1992; none of the potential Phase III facilities in that segment fall into that employment category.

- Ninety-four percent of all facilities in the Organic Chemical segment had fewer than 100 employees in 1992; none of the potential Phase III facilities in that segment fall into that employment category.

Figure B2B-9 shows the number of potential Phase III facilities in the profiled chemical segments by employment size category.

Figure B2B-9: Number of Potential Phase III facilities by Employment Size Category for Profiled Chemical Segments



Source: U.S. EPA, 2000.

B2B-5.3 Firm Size

EPA used the Small Business Administration (SBA) small entity size standards to determine the number of U.S. Phase III facilities in the three profiled chemical segments that are owned by small firms. Firms in the Inorganic Chemicals segment (SIC codes 2812, 2813, 2816, 2819) and in Industrial Organic Chemicals, NEC (SIC code 2869) are defined as small if they have 1,000 or fewer employees; firms in Plastics Material and Resins (SIC 2821) and Cyclic Organic Crudes and Intermediates (SIC code 2865) are defined as small if they have 750 or fewer employees.

Table B2B-12 shows that, of the 64 potential Phase III facilities in the Inorganic Chemicals segment, four, or 7 percent, are owned by a small firm. All four of these firms are in SIC 2819. None of the 19 potential Phase III facilities in the Plastics Material and Resins segment are owned by a small firm. Ninety-three percent of the potential Phase III facilities in the Organic Chemicals segment are classified as large. SIC 2869 accounts for all of the facilities owned by small firms in the Organic Chemicals segment. Overall, the profiled chemicals segment has 135 facilities (94 percent) owned by large firms, and 9 facilities (6 percent) owned by small firms.

Table B2B-12: Number of Potential Phase III facilities by Firm Size for Profiled Chemical Segments

SIC Code	Large		Small		Total
	No.	% of SIC	No.	% of SIC	
Inorganic Chemicals					
2812	20	100%	0	0%	20
2813	4	100%	0	0%	4
2816	9	100%	0	0%	9
2819	26	87%	4	13%	30
Total	***59***	***93%***	***4***	***7%***	*64*
Plastics Material and Resins					
2821	19	100%	0	0%	19
Organic Chemicals					
2865	9	100%	0	0%	9
2869	48	92%	4	8%	52
Total	***57***	***93%***	***4***	***7%***	***61***
Total for Profiled Chemical Facilities					
Total	**135**	**94%**	**9**	**6%**	**144**

Source: U.S. EPA, 2000; U.S. SBA, 2000; D&B, 2001.

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Chapter B2C: Petroleum Refining (SIC 2911)

EPA's *Detailed Industry Questionnaire*, hereafter referred to as the DQ, identified one 4-digit SIC code in the Petroleum and Coal Products Industry (SIC 29) with at least one existing facility that operates a CWIS, holds a NPDES permit, withdraws at least two million gallons per day (MGD) from a water of the United States, and uses at least 25 percent of its intake flow for cooling purposes (facilities with these characteristics are hereafter referred to as facilities potentially subject to the Phase III regulation or "potential Phase III facilities").

Table B2C-1 below provides a description of the industry segment, a list of primary products manufactured, the total number of detailed questionnaire respondents (weighted to represent national results), and the number and percent of potential Phase III facilities within the estimated national total of facilities in the respective industry SIC code groups.

CHAPTER CONTENTS

Table B2C-1: Potential Phase III facilities in the Petroleum and Coal Products Industry (SIC 29)

SIC	SIC Description	Important Products Manufactured	Number of Facilities[a]		
			Total	Potential Phase III facilities [b]	%
2911	Petroleum Refining	Gasoline, kerosene, distillate fuel oils, residual fuel oils, and lubricants, through fractionation or straight distillation of crude oil, redistillation of unfinished petroleum derivatives, cracking, or other processes; aliphatic and aromatic chemicals as byproducts	163	36	22.1%

[a] Number of weighted detailed questionnaire survey respondents.
[b] Individual numbers may not add up due to independent rounding.

Source: U.S. EPA, 2000; Executive Office of the President, 1987. ASM 1998

The table shows that an estimated 36 out of 163 facilities (or 22 percent) in the Petroleum and Coal Products Industry (SIC 29) are potentially subject to this proposed regulation. EPA also estimated the percentage of total production that occurs at facilities potentially subject to the proposed regulation. Total value of shipments for the Petroleum and Coal Products Industry (SIC 29) from the 1998 Annual Survey of Manufacturers is $118.2 billion. Value of shipments, a measure of the dollar value of production, was selected for the basis of this estimate. Because value of shipments data were not collected using the DQ, these data were not available for the sample of Phase III manufacturing facilities potentially subject to the proposed regulation. Total revenue, as reported on the DQ, was used a close approximation for value of shipments for these facilities. EPA estimated the total revenue of facilities in the petroleum industry subject to the proposed regulation is $47.8 billion. Therefore, EPA estimates that 40 percent of total production in the petroleum industry occurs at facilities potentially subject to the proposed regulation.

Table B2C-2 provides the cross-walk between SIC codes and NAICS codes for the profiled petroleum SIC codes. For the Petroleum Refining segment, the translation of NAICS-reported data to the SIC framework is straightforward as these frameworks have a simple one-to-one match for Petroleum Refining: SIC code 2911 and NAICS code 324110.

Table B2C-2: Relationship between SIC and NAICS Codes for the Petroleum and Coal Products Industry (1997)

SIC Code	SIC Description	NAICS Code	NAICS Description	Establishments	Value of Shipments ($000)	Employment
2911	Petroleum Refining	324110	Petroleum Refineries	242	157,525,704	65,471

Source: U.S. DOC, 1997.

B2C-1 SUMMARY INSIGHTS FROM THIS PROFILE

A key purpose of this profile is to provide insight into the ability of Petroleum Refining firms that would be subject to the Phase III regulation to absorb compliance costs without material adverse economic/financial effects. Two important factors in the ability of the industry's ability to withstand compliance costs are: (1) the extent to which the industry may be expected to shift compliance costs to its customers through price increases and (2) the financial health of the industry and its general business outlook.

Likely Ability to Pass Compliance Costs Through to Customers

As reported in the following sections of this profile, the Petroleum Refining segment is relatively unconcentrated, which suggests that firms in this industry would have less power to pass through to customers a significant portion of their compliance-related costs. As discussed above, the proportion of total value of shipments in the industry potentially subject to the proposed regulation is 40 percent. The actual proportion of total value of shipments subject to regulation-induced compliance costs would be smaller since not all of the facilities would be subject to the national categorical requirements of the proposed regulation: that is, facilities below the proposed design intake flow (DIF) would be subject to permitting based on best professional judgement (BPJ) rather than based on national standards, and several facilities currently employ baseline technologies that meet the requirements of the proposed regulation. Given the likelihood that these percentages represent upper bound estimates, EPA believes that the theoretical threshold for justifying the use of industry-wide CPT rates in the impact analysis of potential Phase III refineries has not been met. Even though the Petroleum Refining segment is not characterized by high competitive pressure from foreign markets, the low market concentration leads EPA to believe that the market power held by individual firms is likely to be quite small. For these reasons, in its analysis of regulatory impacts for the Petroleum Refining segment, EPA assumed that complying firms would be unable to pass compliance costs through to customers: i.e., complying facilities must absorb all compliance costs within their financial condition at the time of compliance (see following sections and Appendix 3 to *Chapter B3: Economic Impact Analysis for Manufacturers* for further information).

Financial Health and General Business Outlook

Over the past decade, Petroleum Refining, like other U.S. manufacturing industries, has experienced a range of economic/financial conditions, including substantial challenges. In the early 1990s, the domestic Petroleum Refining segment was affected by reduced U.S. demand as the economy entered a recessionary period Although domestic market conditions improved by mid-decade, oversupply of crude oil, weakness in Asian markets, along with other domestic factors, materially weakened refiners' financial performance in 1998. As petroleum producing countries reduced crude oil supply and refiners cut production, prices rebounded in the late 1990's into 2000, before another U.S. recession, the attacks of 9/11, and global economic downturn again had a negative effect on petroleum refiners. More recently, as the U.S. economy began recovery from its economic weakness, domestic petroleum refiners began showing signs of recovery with higher demand levels and improving financial performance in 2003. Although the industry has weathered difficult periods over the past few years, the strengthening of the industry's financial condition and general business outlook suggest improved ability to withstand additional regulatory compliance costs without imposing significant financial impacts.

B2C-2 DOMESTIC PRODUCTION

The Petroleum Refining segment accounts for about 4 percent of the value of shipments of the U.S. entire manufacturing segment and 0.4 percent of the manufacturing segment's employment (U.S. DOE, 1999a). According to the Annual Survey of Manufactures, in 2001, Petroleum Refineries achieved shipments of approximately $206 billion dollars ($2003) and employed 63,251 people. Petroleum products contribute approximately 40 percent of the total energy used in the United States, including virtually all of the energy consumed in transportation (U.S. DOE, 1999a).

U.S. DOE Energy Information Administration (EIA) data report that there were 149 operable Petroleum Refineries in the U.S. as of January 2003, of which 145 were operating and four were idle (U.S. DOE, 2004)[1]. Some data reported in this profile are taken from EIA publications. Readers should note that the Census data reported for SIC 2911 cover a somewhat broader range of facilities than do the U.S. DOE/EIA data, and the two data sources are therefore not entirely comparable.[2]

The petroleum industry includes exploration and production of crude oil, refining, transportation, and marketing. Petroleum refining is a capital-intensive process that converts crude oil into a variety of refined products. Refineries range in complexity, depending on the types of products produced. Nearly half of all U.S. refinery output is motor gasoline.

The number of U.S. refineries has declined by almost half since the early 1980s. The remaining refineries have improved their efficiency and flexibility to process heavier crude oils by adding "downstream" capacity[3]. While the number of refineries has declined, the average refinery capacity and utilization has increased, resulting in an increase in domestic refinery production overall.

B2C-2.1 Output

Table B2C-3 shows trends in production of petroleum refinery products from 1990 through 2002. In general, output of refined products grew over this period, reflecting growth in transportation demand and other end-uses. Output fell in 1991 due to the domestic economic recession, and the early years of the 2000s experienced little or negative growth due to the downturn of the U.S. economy and events of 9/11 (API, 2003a). At the beginning of 2002, petroleum products were in excess supply in the world market, and the focus was on the elimination of excess supplies and stabilization of prices (U.S. DOE, 2004). In 2003, the industry rebounded, with refinery processing increasing 2 percent, producing record or near record levels of gasoline and distillate (API 2004). Petroleum demand in 2004 is expected to increase 1.1 percent. As the U.S. and global economy improves, Petroleum Refining firms should continue to see improving results in their markets and earnings. This should place companies in a better position to incur any costs associated with regulatory compliance.

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[1]In addition, there was one operating and one idle refinery in Puerto Rico and one operating refinery in the Virgin Islands.

[2]For comparison, preliminary 1997 Census data included 244 establishments for NAICS 3241/SIC 2911, whereas U.S. DOE/EIA reported 164 operable refineries as of January 1997.

[3]The first step in refining is atmospheric distillation, which uses heat to separate various hydrocarbon components in crude oil. Beyond this basic step are more complex operations (generally referred to as "downstream" from the initial distillation) that increase the refinery's capacity to process a wide range of crude oils and increase the yield of lighter (low-boiling point) products such as gasoline. These downstream operations include vacuum distillation, cracking units, reforming units, and other processes (U.S. DOE, 1999a).

Table B2C-3: U.S. Petroleum Refinery Product Production (million barrels per day)

Year	Motor Gasoline	Distillate Fuel Oil	Jet Fuel	Residual Fuel Oil	Other Products[a]	Total Output	Percent Change
1990	6.96	2.92	1.49	0.95	2.95	15.27	n/a
1991	6.98	2.96	1.44	0.93	2.95	15.26	-0.1%
1992	7.08	2.98	1.40	0.89	3.08	15.44	1.2%
1993	7.30	3.13	1.42	0.84	3.09	15.79	2.2%
1994	7.18	3.20	1.45	0.83	3.13	15.79	0.0%
1995	7.46	3.16	1.42	0.79	3.18	15.99	1.3%
1996	7.59	3.32	1.52	0.73	3.21	16.37	2.3%
1997	7.74	3.39	1.55	0.71	3.36	16.76	2.4%
1998	7.89	3.42	1.53	0.76	3.43	17.03	1.6%
1999	7.93	3.40	1.57	0.70	3.39	16.99	-0.2%
2000	7.97	3.59	1.61	0.70	3.42	17.29	1.8%
2001	8.02	3.69	1.53	0.72	3.32	17.28	0.0%
2002	8.17	3.59	1.51	0.60	3.38	17.25	-0.2%
Total Percent Change 1990-2002	17.4%	22.7%	1.7%	-36.9%	14.5%	13.0%	
Average Annual Growth Rate	1.3%	1.7%	0.1%	-3.8%	1.1%	1.0%	

[a] Includes asphalt and road oil, liquified petroleum gases, petroleum coke, still gas, kerosene, petrochemical feedstocks, lubricants, wax, aviation gasoline, special napthas, and miscellaneous products.
[b] Monthly data for motor gasoline production include blending of fuel ethanol and an adjustment to correct for the imbalance of motor gasoline blending components.

Source: U.S. DOE, 2001b, and 2001c; U.S. DOE, 2004.

Value of shipments and ***value added*** are two common measures of manufacturing output[4]. They provide insight into the overall economic health and outlook for an industry. Value of shipments is the sum of the receipts a manufacturer earns from the sale of its outputs; it indicates the overall size of a market or the size of a firm in relation to its market or competitors. Value added measures the value of production activity in a particular industry. It is the difference between the value of shipments and the value of inputs used to make the products sold.

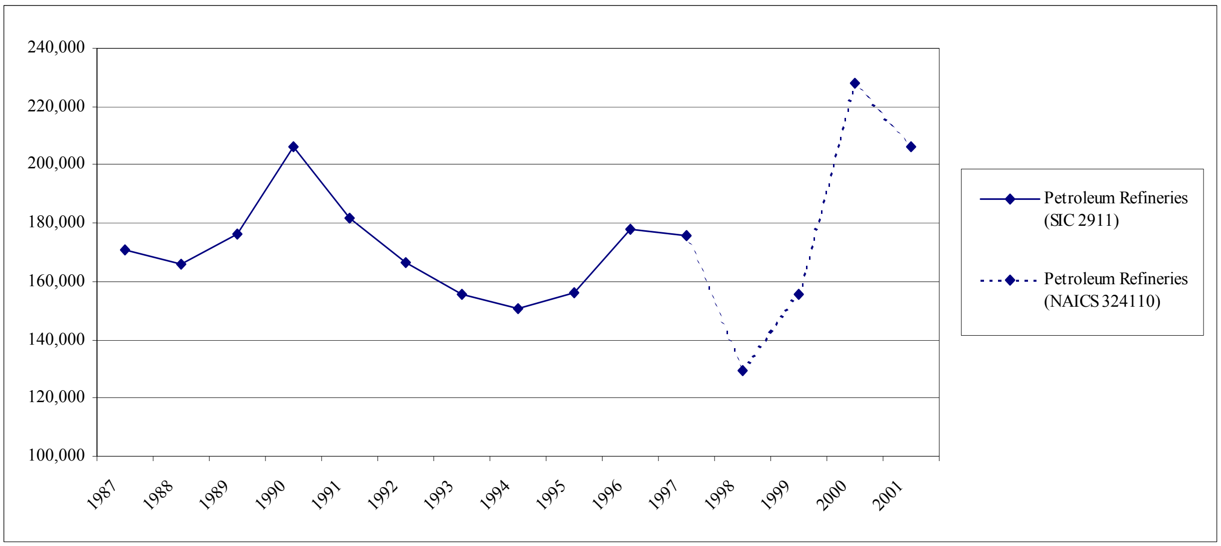
Figure B2C-1 on the following page shows value of shipments and value added for petroleum products from 1987 to 2001. Value of shipments rose through 1990; however, during and following the recession of 1991, value of shipments fell through 1994. This was followed by some volatility in value over the next few years until experiencing a sharp drop in 1998, when a range of factors led to a dramatic decrease in petroleum prices. Increased production quotas by OPEC, increased production from Iraq through the "oil-for-food" program, weak demand in Asia due to their financial crisis, and a warm winter in the U.S. all increased the supply of petroleum products (U.S. DOE, 1999c). Estimates of worldwide petroleum supply exceeding demand during 1998 range from 1.47 millions barrels per day to 2.4 million barrels per day (World Oil, 1999). As crude oil producers and

[4]Terms highlighted in bold and italic font are further explained in the glossary.

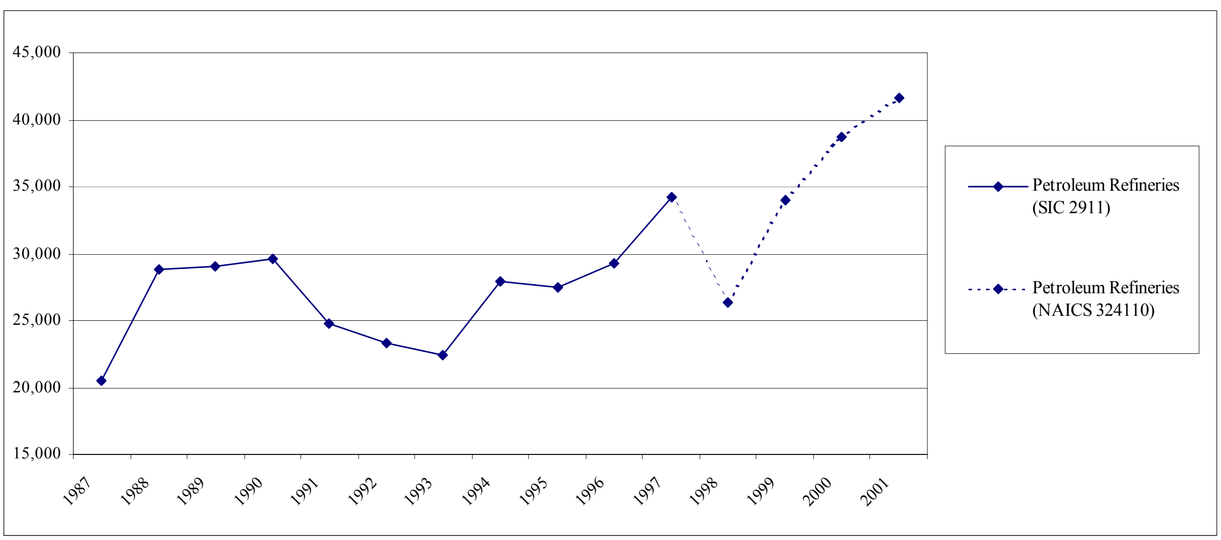
refiners cutback on production, the industry rebounded with significant improvements in 1999 and 2000, before the latest recession and global economic slowdown and weakening demand decreased the value of shipments in 2001. Value added generally followed the path of value of shipments over this time period, though it did not quite have the volatility of the value of shipments.

Figure B2C-1: Value of Shipments and Value Added for Petroleum Refineries (millions, $2003)

Value of Shipments



Value Added



[a] Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

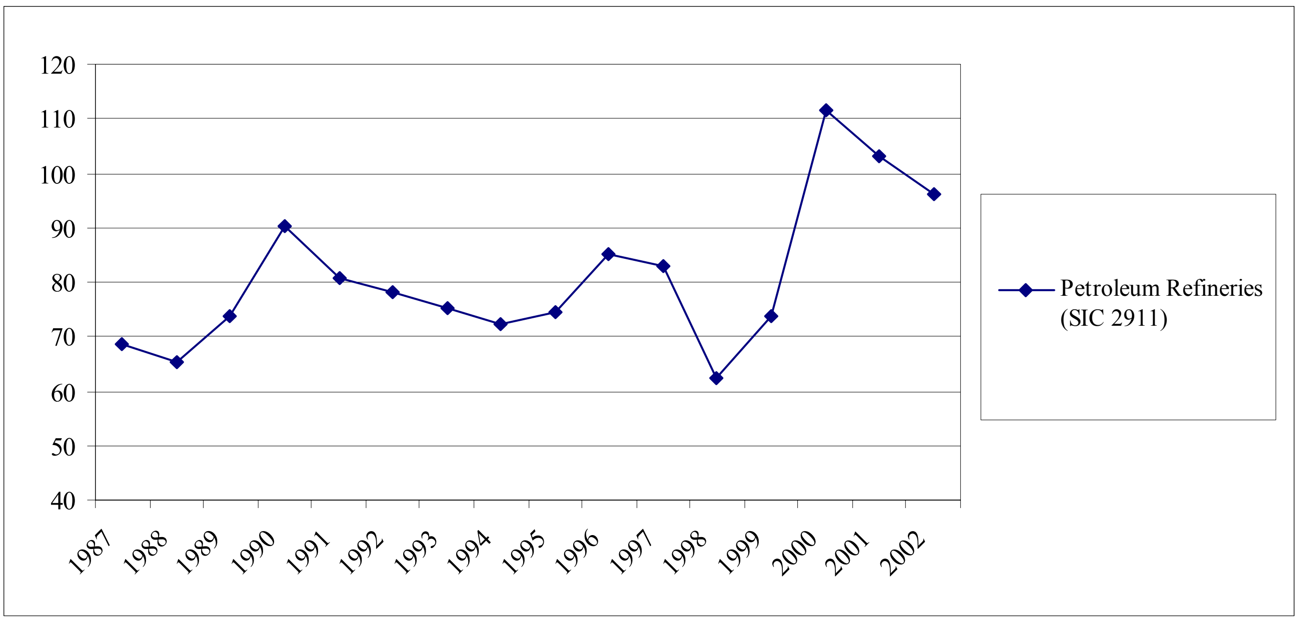
Source: U.S. DOC, 1988-1991, 1993-1996 and 1998 - 2001; U.S. DOC, 1987, 1992 and 1997.

B2C-2.2 Prices

The ***producer price index*** (PPI) measures price changes, by segment, from the perspective of the seller, and indicates the overall trend of product pricing, and thus supply-demand conditions, within a segment.

Figure B2C-2 shows substantial fluctuations in petroleum product prices between 1987 and 2002. Through the early 1990s, refiners faced declining prices due to the effects of the 1991 recession and weak demand before rebounding somewhat in the mid 1990s. Prices plummeted in 1998 as a massive oversupply of petroleum products coupled with decreased demand led to significant drops in petroleum prices. As the subsequent production cutbacks took hold and the glut of supply dwindled, prices recovered in 1999 and 2000, as shown in Figure B2C-2. The higher prices reflect low refinery product inventories and higher crude oil input prices (Value Line, 2001). Excess supply, the global recession, impacts from 9/11, and the relatively warm winter of 2001-2002 led to decreases in prices in subsequent years (U.S. DOE, 2004).

Figure B2C-2: Producer Price Index for Petroleum Refineries

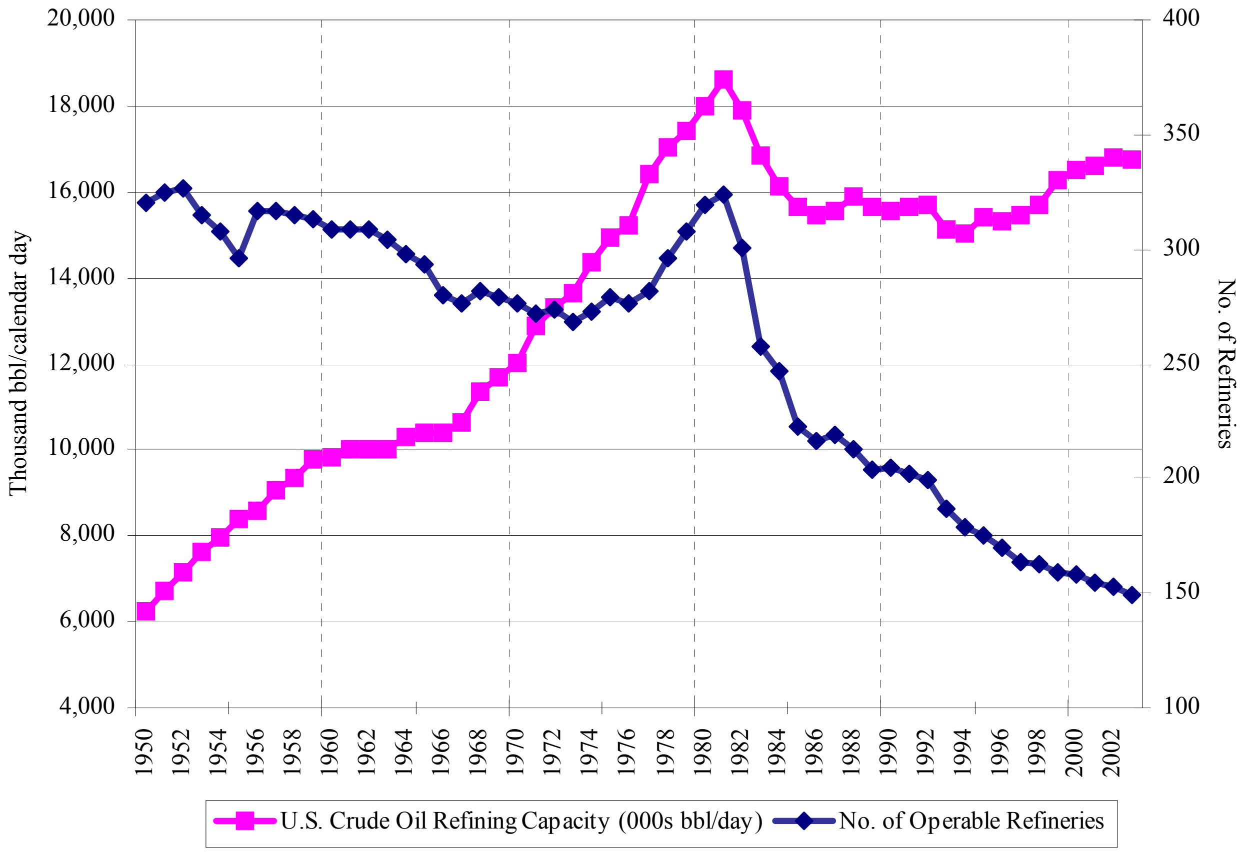


Source: BLS, 2002.

B2C-2.3 Number of Facilities and Firms

Figure B2C-3 shows historical trends in the number of refineries and in refinery capacity. This figure shows that the number of operable refineries fell substantially during the 1980s, with a more gradual reduction in refineries continuing through the 1990s and into the 2000s. This decrease resulted in part from the elimination of the Crude Oil Entitlements Program in the early 1980s. The Entitlements Program encouraged smaller refineries to add capacity throughout the 1970s. After the program was eliminated, surplus capacity and falling profit margins led to the closure of less efficient capacity (U.S. DOE, 1999a). The decrease in the number of refineries continued, as the industry consolidated to improve margins. After peaking in the early 1980s, refining capacity decreased throughout the rest of the decade. Refining capacity has remained relatively stable since the decrease in the 1980s, with a slight upward trend occurring in the latter part of the 1990s into the 2000s. This trend is expected to continue, with no new "greenfield" refineries likely to be built in the U.S., but continuing capacity expansion at existing facilities (S&P, 2001).

Figure B2C-3: Trends in Numbers of Refineries and Refining Capacity 1949-2003



Source: U.S. DOE, 2001a; U.S. DOE, 2004.

Data from the Statistics of U.S. Businesses for SIC 2911 (Table B2C-4) show that the number of firms reporting Petroleum Refining as their primary business also declined since 1990.

Table B2C-4: Number of Firms and Facilities for Petroleum Refineries

Year	Firms		Facilities	
	Number	Percent Change	Number	Percent Change
1990	215	n/a	340	n/a
1991	215	0.0%	346	1.8%
1992	185	-14.0%	303	-12.4%
1993	148	-20.0%	251	-17.2%
1994	161	8.8%	265	5.6%
1995	150	-6.8%	251	-5.3%
1996	173	15.3%	275	9.6%
1997	128	-26.0%	248	-9.8%
1998[a]	155	21.1%	304	22.6%
1999[a]	145	-6.5%	292	-3.9%
2000[a]	162	11.7%	298	2.1%
2001[a]	165	1.9%	302	1.3%
Total Percent Change 1990 - 2001	-23.3%		-11.2%	
Average Annual Growth Rate	-2.4%		-1.1%	

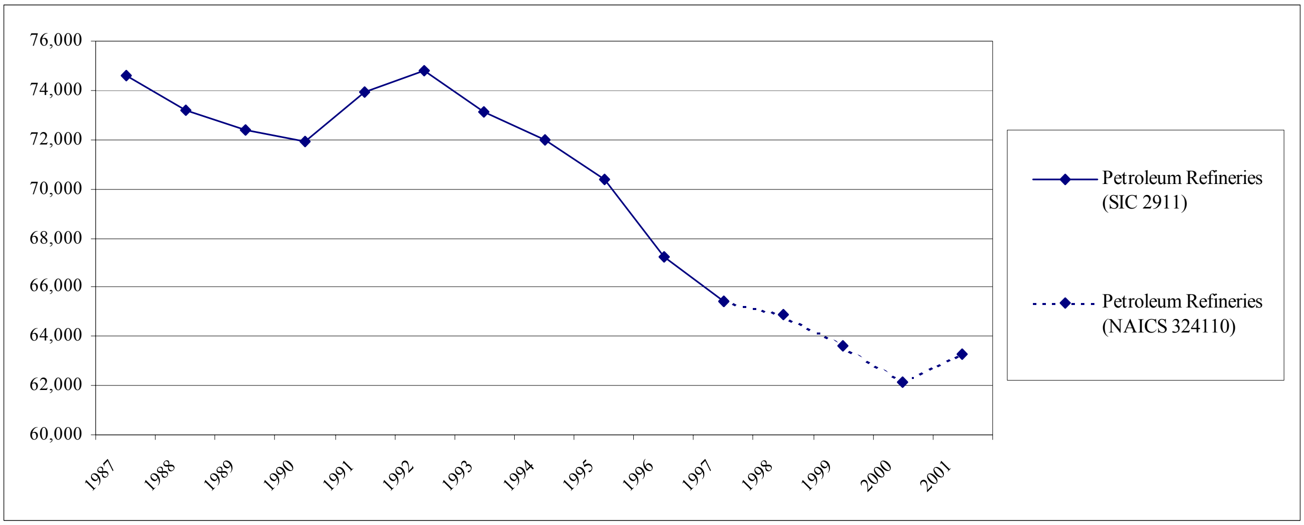
[a] Before 1998, these data were compiled in the Standard Industrial Classification (SIC) system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC.*.

Source: U.S. SBA, 1989-2001.

B2C-2.4 Employment and Productivity

Employment in the Petroleum Refining segment declined by 15 percent between 1987 and 2001, from 74,600 to 63,258 employees, as shown in Figure B2C-4. After increasing in the early 1990s, employment at Petroleum Refineries declined until 2000, before increasing slightly, reflecting overall industry consolidation.

Figure B2C-4: Employment for Petroleum Refineries



[a] Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

Source: U.S. DOC, 1988-1991, 1993-1996, and 1998 -2001; U.S. DOC, 1987, 1992, and 1997.

Table B2C-5 shows substantial year-to-year changes in ***labor productivity***, measured by value added per production hour. These fluctuations reflect volatility in value added, which in turn reflect variations in the relationship between input prices (primarily crude oil) and refinery product prices. Changes in production hours from year to year were less volatile, with a net reduction over the period 1987 to 2001. Value added , however, was not affected as it more than doubled over the same period.

Table B2C-5: Productivity Trends for Petroleum Refineries ($2003)

Year	Value Added (millions)	Production Hours (millions)	Value Added/Hour	
			($/hr)	Value Added/ Hour
1987	20,524	103	199	n/a
1988	28,875	103	281	41.2%
1989	29,024	105	277	-1.1%
1990	29,553	106	279	0.7%
1991	24,767	107	233	-16.7%
1992	23,361	109	214	-8.1%
1993	22,367	107	210	-1.7%
1994	27,865	110	253	20.6%
1995	27,505	107	258	1.8%
1996	29,276	103	285	10.7%
1997	34,192	100	342	20.0%
1998[a]	26,310	98	269	-21.4%
1999[a]	34,023	94	362	34.4%
2000[a]	38,705	92	419	15.9%
2001[a]	41,627	94	445	6.2%
Total Percent Change 1987-2001	102.8%	-9.5%	124.0%	
Annual Average Growth Rate	5.2%	-0.7%	5.9%	

[a] Before 1998, these data were compiled in the Standard Industrial Classification (SIC) system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC.*

Source: U.S. DOC, 1988-1991, 1993-1996, and 1998 - 2001; U.S. DOC, 1987, 1992, and 1997.

B2C-2.5 Capital Expenditures

Petroleum industry capital expenditures increased substantially between 1988 and 1993, but generally decreased afterwards through the latest data year, 2001, as shown in Table B2C-6. In 2001, the industry spent almost $5 billion ($2003), as compared with $2.9 billion ($2003) in 1988. Although this represents a 69 percent increase from 1988 to 2001, it is a 34 percent drop from what was spent in 1993, when capital expenditures peaked at $7.5 billion per year in real terms. Much recent investment in Petroleum Refineries has been to expand and debottleneck units downstream from distillation, partially in response to environmental requirements. Changes in refinery configurations have included adding catalytic cracking units, installing additional sulfur removal hydrotreaters, and using manufacturing additives such as oxygenates. These process changes have resulted from two factors:

- processing of heavier crudes with higher levels of sulfur and metals; and
- regulations requiring gasoline reformulation to reduce volatiles in gasoline and production of diesel fuels with reduced sulfur content (U.S. EPA, 1996b).

Environmentally-related investments have also accounted for a substantial part of capital expenditures. In the future, substantial capital investments by refineries will be required to comply with: product quality regulations, including EPA's Tier 2 Gasoline Sulfur Rule requiring reductions in the sulfur content of gasoline; reductions or elimination of the use of MTBE in gasoline; and proposed sulfur reductions in highway diesel fuel (NPC, 2000).

Table B2C-6: Capital Expenditures for Petroleum Refineries

Year	Capital Expenditures (millions, $2003)	% Change
1988	2,937	n/a
1989	3,248	10.6%
1990	4,017	23.7%
1991	4,945	23.1%
1992	7,007	41.7%
1993	7,509	7.2%
1994	7,156	-4.7%
1995	6,466	-9.6%
1996	6,729	4.1%
1997	5,850	-13.1%
1998[a]	4,700	-19.7%
1999[a]	4,566	-2.9%
2000[a]	4,257	-6.8%
2001[a]	4,949	16.3%
Total Percent Change 1987 - 2001	*68.5%*	
Average Annual Growth Rate	*4.1%*	

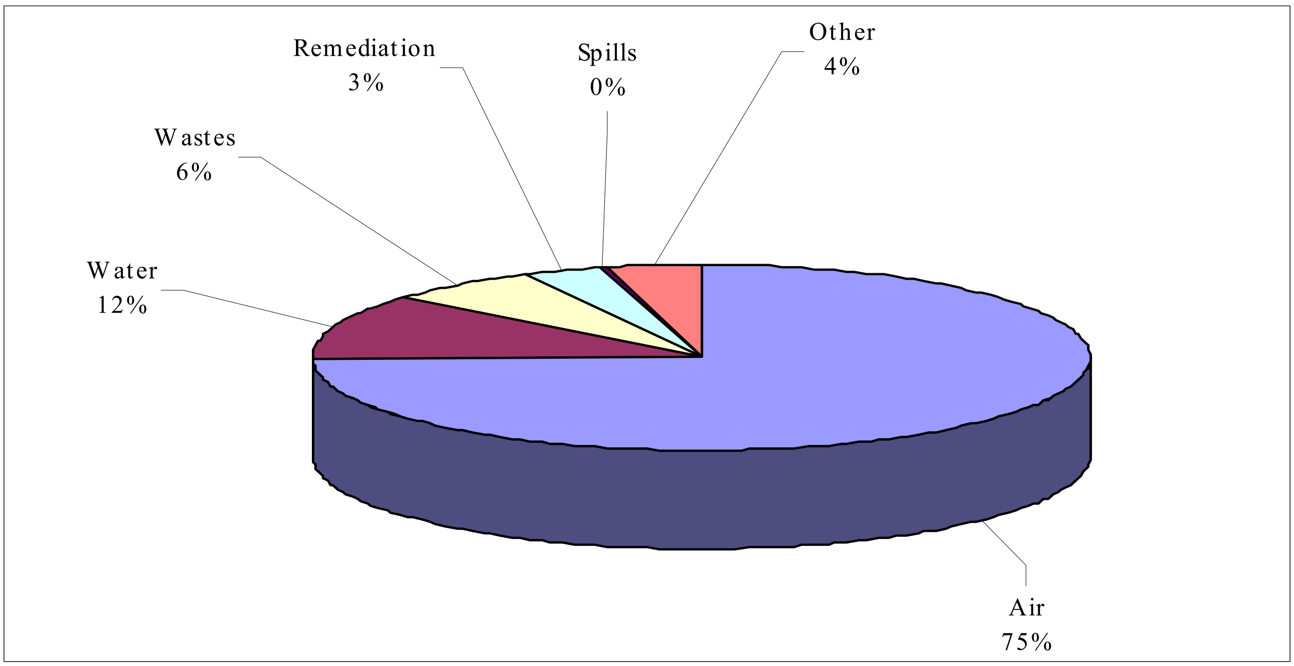
[a] Before 1998, these data were compiled in the Standard Industrial Classification (SIC) system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC.*

Source: U.S. DOC, 1988-1991, 1993-1996, and 1998 - 2001; U.S. DOC, 1987, 1992, and 1997.

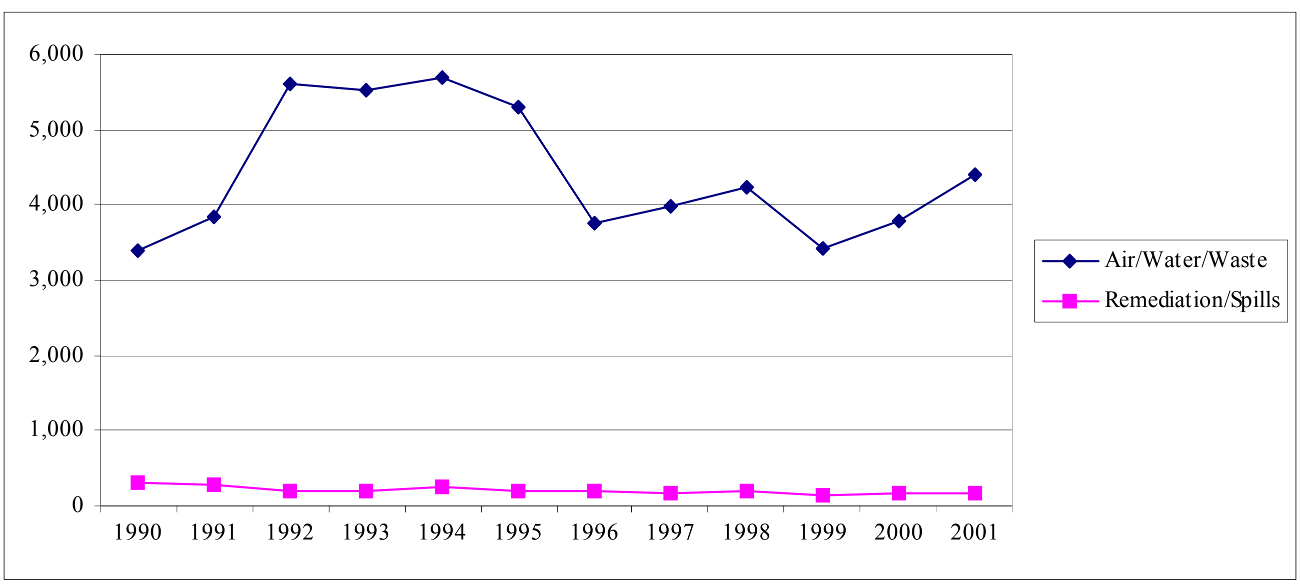
Figure B2C-5 shows pollution control expenditures (capital plus operating costs), reported by American Petroleum Institute (API) members. Expenditures to control current environmental releases (air, water and waste) account for the largest share of total pollution control expenditures. API estimates that the U.S. oil and natural gas industry spent $7.875 billion in 2001 for environmental protection. Of the total 2001 environmental expenditures to address air, water, and waste pollution from on-going operations, 32 percent ($2.5 billion) was capital expenditures and 66 percent ($5.2 billion) was operating maintenance (API, 2003b).

Figure B2C-5: Environmental Expenditures by Type and Medium for Petroleum Refineries

Environmental Expenditures by Type, 2001



Refining Expenditures by Aggregated Types (in millions)



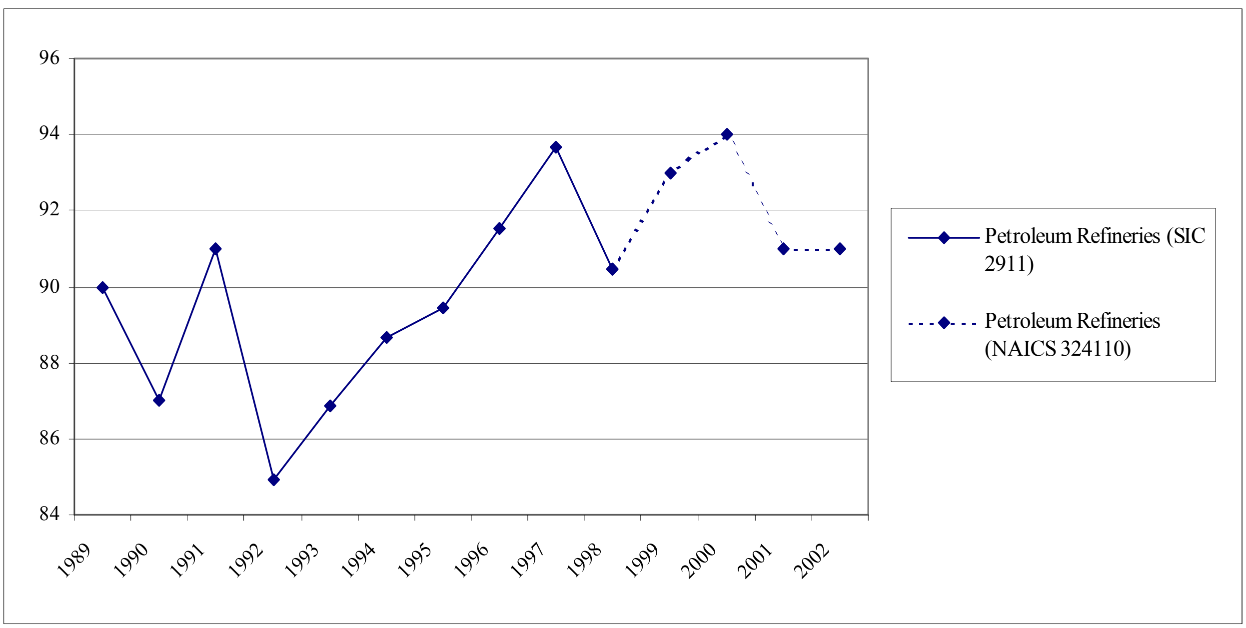
Source: API, 2001; API, 2003b.

B2C-2.6 Capacity Utilization

Refinery capacity is frequently measured in terms of crude oil distillation capacity. EIA defines refinery capacity utilization as input divided by calendar day capacity, which is the maximum amount of crude oil input that can be processed during a 24-hour period with certain limitations. Some downstream refinery capacities are measured in terms of "stream days," which is the amount a unit can process when running full capacity under optimal crude and product mix conditions for 24 hours (U.S. DOE, 1999a). Downstream capacities are reported only for specific units or products, and are not summed across products, since not all products could be produced at the reported levels simultaneously.

Figure B2C-6 below shows the fluctuation in utilization rates over the period 1989-2002, based Census Bureau data. Capacity utilization fluctuated over a relatively lower range between 1989-1992, followed by an increase in utilization rates for five straight years, concluding in 1997. After decreasing in 1998, utilization rates climbed until 2000, before excess supply, recession, and other factors led to decreases in rates in the early 2000s. The industry appears to be recovering, however, as the American Petroleum Institute (2004) reports that refineries operated at 92.4 percent of capacity for 2003. Overall refinery utilization has remained high over this entire time period. Capacity utilization relative for production o specific products may vary, however, as the industry adjusts to changes in the desired product mix and characteristics.

Figure B2C-6: Capacity Utilization Rates (Fourth Quarter) for Petroleum Refineries



[a] Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

Source: *U.S. DOC, 1989-2002.*

B2C-3 STRUCTURE AND COMPETITIVENESS

The Petroleum Refining segment in the United States is made up of integrated international oil companies, integrated domestic oil companies, and independent domestic refining/marketing companies. In general, the petroleum industry is highly integrated, with many firms involved in more than one stage of petroleum industry operations. Large companies, referred to as the "majors," are fully integrated across crude oil exploration and production, refining, and marketing. Smaller, nonintegrated companies, referred to as the "independents," generally specialize in one segment of the industry.

Like the oil business in general, refining was dominated in the 1990s by integrated internationals, specifically a few large companies such as Exxon Corporation, Mobil Corporation, and Chevron Corporation. These three ranked in the top ten of Fortune's 500 sales during this time period. Substantial diversification by major petroleum companies into other energy and non-energy segments was financed by high oil prices in the 1970s and 1980s. With lower profitability in the 1990s, the major producers began to exit nonconventional energy operations (e.g., oil shale) as well as coal and non-energy operations in the 1990s. Some have recently ceased chemical production.

During the 1990s and into the early 2000s, several mergers, acquisitions, and joint ventures occurred in the Petroleum Refining segment in an effort to cut cost and increase profitability. This consolidation has taken place among the largest firms (as illustrated by the acquisition of Amoco Corporation by British Petroleum in 1999, the merger of Chevron and Texaco in 2001, the merger of Conoco and Phillips in 2002, and the mega-merger of Exxon and Mobil Corporation in 1998) as well as among independent refiners and marketers (e.g., the independent refiner/marketer Ultramar Diamond Shamrock (UDS) acquired Total Petroleum North America in 1997) (U.S. DOE, 1999b, 2004). Merger activity seems to have slowed since 2002, however, possibly as companies seek to address financial issues or wait to see that the recent positive economic growth continues (U.S. DOE, 2004).

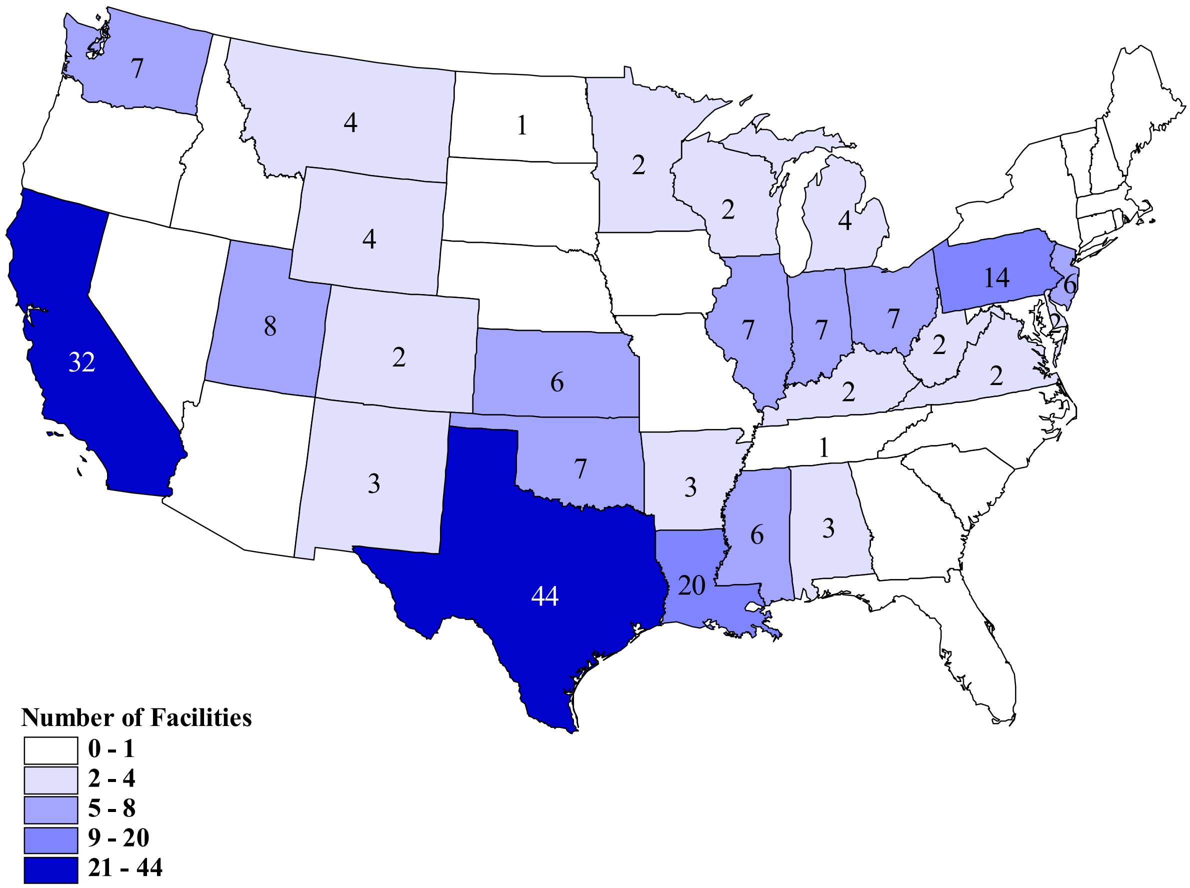
B2C-3.1 Geographic Distribution

Petroleum Refining facilities are more often located in areas near crude oil sources and/or near consumers. The cost of transporting crude oil feed stocks and finished products is an important influence on the location of refineries. Most Petroleum Refineries are located along the Gulf Coast and near the heavily industrialized areas of both the east and west coasts (U.S. DOE, 1997).

Figure B2C-7 shows the distribution of all facilities by State in the profiled petroleum segments, based on the 1992 Census of Manufactures[5]. In 1992, 44 refineries were located in Texas, 32 in California, and 20 in Louisiana, accounting for 43 percent of SIC 2911 facilities in the United States.

[5] The *1992 Census of Manufactures* is the most recent data available by SIC code and State.

Figure B2C-7: Geographic Distribution of Petroleum Refineries



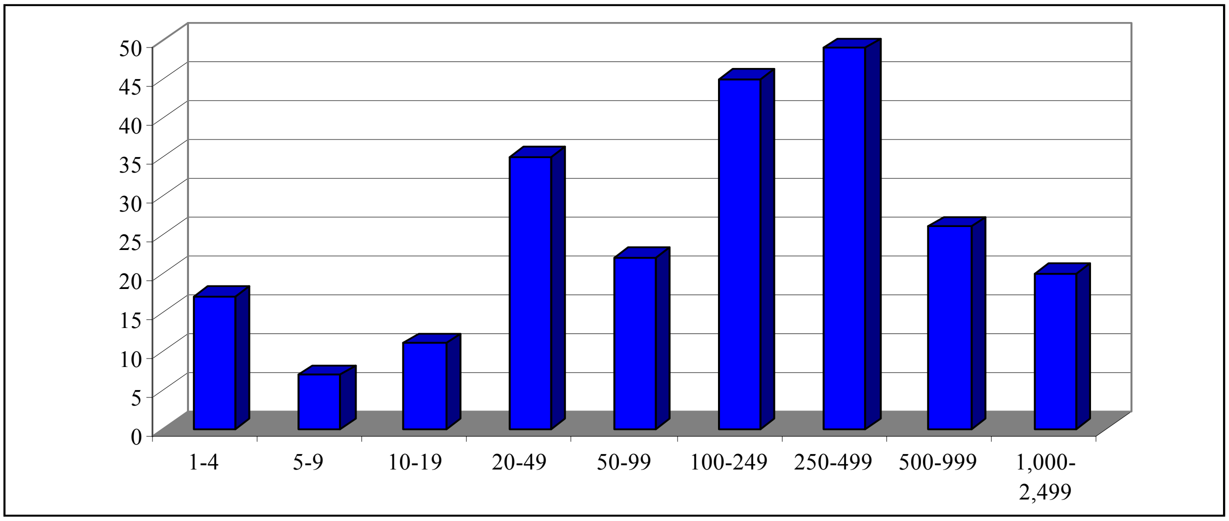
Source: U.S. DOC, 1987, 1992, and 1997.

B2C-3.2 Facility Size

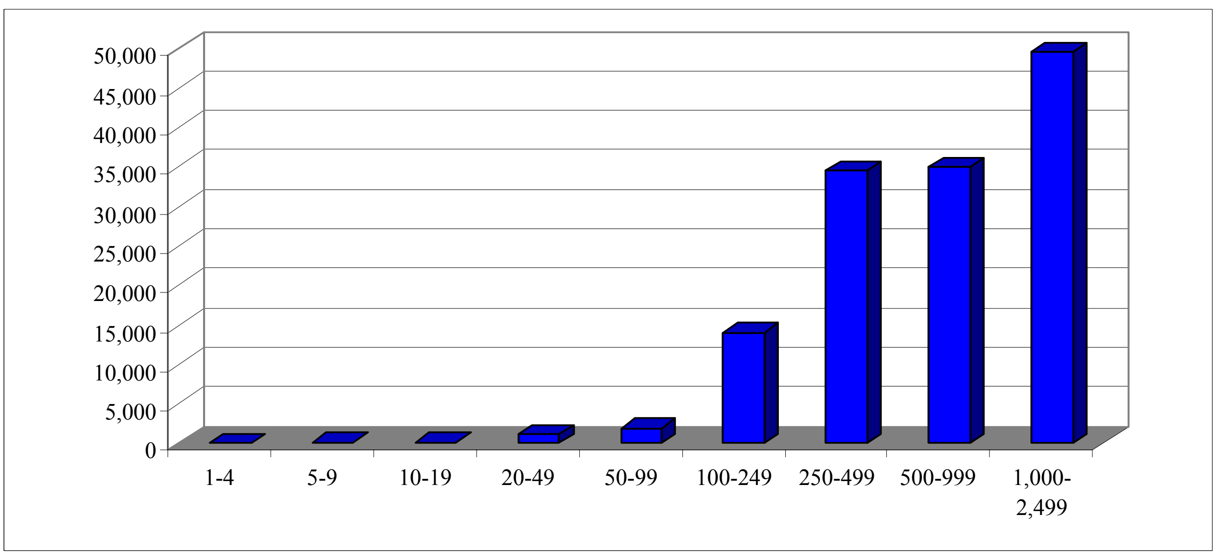
A substantial portion of the facilities in SIC 2911 employ a large number of employees, with 41 percent having 250 or more employees. Figure B2C-8 shows that approximately 87 percent of the value of shipments for the industry is produced by the 41 percent of establishments with more than 250 employees. Establishments with more than 1,000 employees are responsible for approximately 36 percent of all industry shipments.

Figure B2C-8: Value of Shipments and Number of Facilities in 1992[a] for Petroleum Refineries by Employment Size Category

Number of Facilities



Value of Shipments ($ millions)



[a] The *1992 Census of Manufactures* is the most recent data available by SIC code and facility employment size.

Source: U.S. DOC, 1987, 1992, and 1997.

B2C-3.3 Firm Size

For SIC 2911, the Small Business Administration defines a small firm as having 1,500 or fewer employees. The size categories reported in the Statistics of U.S. Businesses (SUSB) do not correspond with the SBA size classifications, therefore preventing precise use of the SBA size threshold in conjunction with SUSB data. Table B2C-7 below shows the distribution of firms and establishments in SIC 2911 by the employment size of the parent firm. The SUSB data show that 180 of the 302 SIC 2911 establishments reported for 2001 (60 percent) are owned by larger firms (those with 500 employees or more), some of which may still be defined as small under the SBA definition, and 112 (40 percent) are owned by small firms (those with fewer than 500 employees).

Table B2C-7: Number of Firms, Establishments, and Estimated Receipts for Petroleum Refineries by Firm Employment Size Category (2001)

Employment Size Category	Number of Firms	Number of Establishments
0-19	71	71
20-99	22	23
100-499	23	28
500+	49	180
Total	*165*	*302*

[a] Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

Source: U.S. SBA, 1989-2001.

B2C-3.4 Concentration Ratios

Concentration is the degree to which industry output is concentrated in a few large firms. Concentration is closely related to entry barriers, with more concentrated industries generally having higher barriers.

The four-firm ***concentration ratio*** (CR4) and the ***Herfindahl-Hirschman Index*** (HHI) are common measures of industry concentration. The CR4 indicates the market share of the four largest firms. For example, a CR4 of 72 percent means that the four largest firms in the industry account for 72 percent of the industry's total value of shipments. The higher the concentration ratio, the less competition there is in the industry, other things being equal[6]. An industry with a CR4 of more than 50 percent is generally considered concentrated. The HHI indicates concentration based on the largest 50 firms in the industry. It is equal to the sum of the squares of the market shares for the largest 50 firms in the industry. For example, if an industry consists of only three firms with market shares of 60, 30, and 10 percent, respectively, the HHI of this industry would be equal to 4,600 (602 + 302 + 102). The higher the index, the fewer the number of firms supplying the industry and the more concentrated the industry. Based on the U.S. Department of Justice's guidelines for evaluating mergers, markets in which the HHI is under 1000 are considered unconcentrated, markets in which the HHI is between 1000 and 1800 are considered to be moderately concentrated, and those in which the HHI is in excess of 1800 are considered to be concentrated.

[6]Note that the measured concentration ratio and the HHF are very sensitive to how the industry is defined. An industry with a high concentration in domestic production may nonetheless be subject to significant competitive pressures if it competes with foreign producers or if it competes with products produced by other industries (e.g., plastics vs. aluminum in beverage containers). Concentration ratios based on share of domestic production are therefore only one indicator of the extent of competition in an industry.

As shown in Table B2C-8, the CR4 and the HHI for SIC 2911 are both below the benchmarks of 50 percent and 1,000, respectively. For the Petroleum Refining segment, the HHI is 422, suggesting the sector is unconcentrated. With the majority of the firms in this industry having small market shares, this suggests limited potential for passing through to customers any increase in production costs resulting from regulatory compliance.

Table B2C-8: Selected Ratios for Petroleum Refineries

SIC	Year	Total Number of Firms	Concentration Ratios				
			4 Firm (CR4)	8 Firm (CR8)	20 Firm (CR20)	50 Firm (CR50)	Herfindahl-Hirschman Index
2911	1987	200	32%	52%	78%	95%	435
	1992	132	30%	49%	78%	97%	414
	1997	122	28%	49%	83%	98%	422

Source: U.S. DOE, 1987, 1992, and 1997.

B2C-3.5 Foreign Trade

This profile uses two measures of foreign competition: ***export dependence*** and ***import penetration***.

Import penetration measures the extent to which domestic firms are exposed to foreign competition in domestic markets. Import penetration is calculated as total imports divided by total value of domestic consumption in that industry: where domestic consumption equals domestic production plus imports minus exports. Theory suggests that higher import penetration levels will reduce market power and pricing discretion because foreign competition limits domestic firms' ability to exercise such power. Firms belonging to segments in which imports account for a relatively large share of domestic sales would therefore be at a relative disadvantage in their ability to pass-through costs because foreign producers would not incur costs as a result of the Phase III regulation. The estimated import penetration ratio for the entire U.S. manufacturing sector (NAICS 31-33) for 2001 is 22 percent. For characterizing the ability of industries to withstand compliance cost burdens, EPA judges that industries with import ratios close to or above 22 percent would more likely face stiff competition from foreign firms and thus be less likely to succeed in passing compliance costs through to customers.

Export dependence, calculated as exports divided by value of shipments, measures the share of a segment's sales that is presumed subject to strong foreign competition in export markets. The Phase III regulation would not increase the production costs of foreign producers with whom domestic firms must compete in export markets. As a result, firms in industries that rely to a greater extent on export sales would have less latitude in increasing prices to recover cost increases resulting from regulation-induced increases in production costs. The estimated export dependence ratio for the entire U.S. manufacturing sector for 2001 is 15 percent. For characterizing the ability of industries to withstand compliance cost burdens, EPA judges that industries with export ratios close to or above 15 percent are at a relatively greater disadvantage in potentially recovering compliance costs through price increases since export sales are presumed subject to substantial competition from foreign producers.

Table 4D-9 presents trade statistics for the profiled Petroleum Refining segment from 1989 to 2001. The table shows that while export dependence has been relatively stable, import penetration decreased during the economic weakness of the early 1990s, before leveling off through the mid 1990s. Import penetration increased steadily through 2000 and then dropped slightly in 2001. This cycle follows the growth in the U.S. economy of the late 1990s, followed by the subsequent economic slowdown arriving in the latter half of 2000 into 2001. Mexico received the largest amount of U.S. exported refined petroleum products in 2001, followed by Canada and Japan. Imports of refined petroleum products increased 47.3 percent from 1989 to 2001, with 46.6 percent of total imports coming from OPEC countries (U.S. DOE, 2003b).

The import penetration ratio for facilities in the Petroleum Refining segment in 2001 was only 15 percent, well below the U.S. manufacturing segment average of 22 percent. The export dependence ratio for petroleum refiners in 2001 was only four percent compared to the U.S. manufacturing average of 15 percent. Thus, based on the lack of competitive pressures from foreign markets/firms, the petroleum industry appears to be in a position to pass-through to consumers a significant portion of compliance-related costs associated with the Phase III regulation. However, given the low HHI for this industry EPA believes that existing market competition among domestic firms most likely nullifies any favorable influence the lack of foreign competitors would have on increasing the market power of firms in this industry.

Table B2C-9: Foreign Trade Statistics for Petroleum Refining

Year	Value of Imports (millions, $2003)	Value of Exports (millions, $2003)	Value of Shipments (millions, $2003)	Implied Domestic Consumption[a]	Import Penetration[b]	Export Dependence
B2989	15,867	5,807	176,444	186,504	8.5%	3.3%
1990	18,477	7,754	206,424	217,147	8.5%	3.8%
1991	13,625	7,952	181,906	187,579	7.3%	4.4%
1992	12,457	7,043	166,625	172,039	7.2%	4.2%
1993	11,646	6,743	155,357	160,260	7.3%	4.3%
1994	10,856	5,804	150,633	155,685	7.0%	3.9%
1995	10,054	6,117	156,200	160,137	6.3%	3.9%
1996	20,837	7,092	177,942	191,687	10.9%	4.0%
1997[d]	22,627	7,621	175,693	190,699	11.9%	4.3%
1998[d]	18,683	5,680	129,399	142,402	13.1%	4.4%
1999[d]	23,627	6,221	155,768	173,174	13.6%	4.0%
2000[d]	42,334	9,221	227,748	260,861	16.2%	4.0%
2001[d]	36,252	8,333	206,312	234,231	15.5%	4.0%
Total Percent Change 1989-2001	*128.5%*	*43.5%*	*16.9%*			
Average Annual Growth Rate	*7.1%*	*3.1%*	*1.3%*			

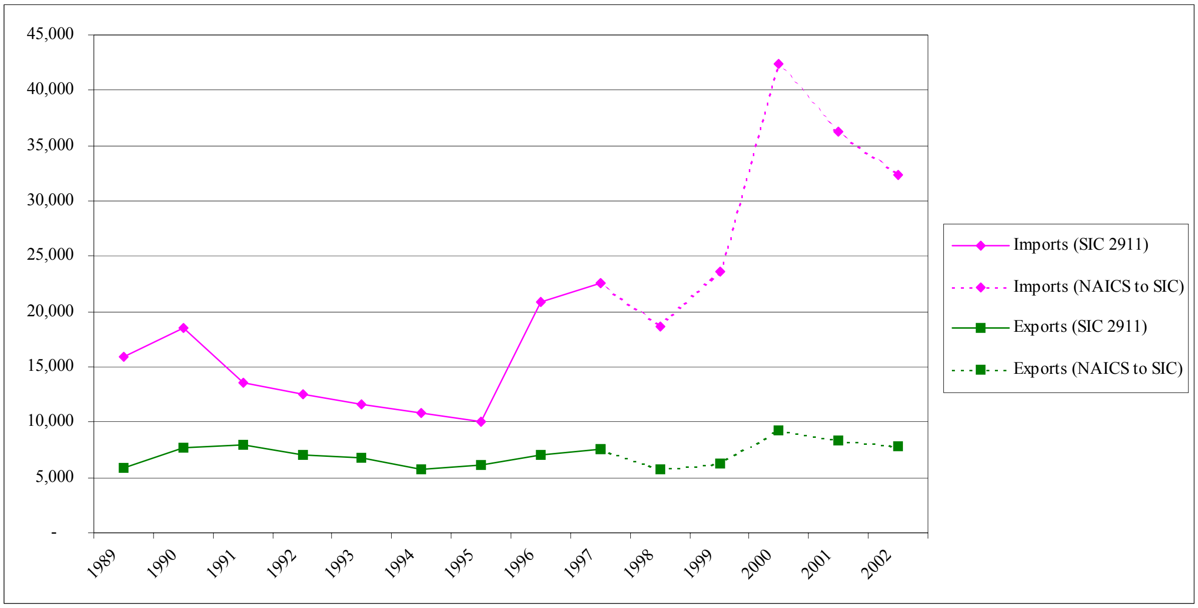
Calculated by EPA as shipments + imports - exports.
[b] Calculated by EPA as imports divided by implied domestic consumption.
[c] Calculated by EPA as exports divided by shipments.
[d] Before 1998, these data were compiled in the Standard Industrial Classification (SIC) system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC.*.

Source: U.S. DOC, 2001; U.S. DOC 1988-1991, 1993-1996, and 1998 - 2001; U.S. DOE, 2001b.

The United States consumes more petroleum than it produces, requiring net imports of both crude oil and products to meet domestic demand. In 2002, the U.S. imported 9.05 million barrels per day (MBD) of crude oil and 2.31 MBD of refined products. These refined product imports represented roughly 12 percent of the 19.65 MBD of refined products supplied to U.S. consumers. The U.S. exported 0.97 MBD of refined products in 2002 (U.S. DOE, 2003b).

Imports of refined petroleum products have fluctuated since 1985. Imports rose to 2.3 MB in the early 1980s, due to rapid growth in oil consumption, especially consumption of light products, which exceeded the growth in U.S. refining capacity. Imports then declined as a result of the 1990/91 recession and increased upgrading of refinery capacity resulting primarily from the 1990 Clean Air Act Amendments and other environmental requirements (U.S. DOE, 1997). Since the 1995 low point, imports steadily increased through 2000 with the exception of 1998, before dropping again, due to general economic weakness, in 2001 and 2002 (see Figure B2C-9).

Figure B2C-9: Value of Imports and Exports for Petroleum Refining (millions, $2003)



[a] Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

Source: U.S. DOE, 2001b.; U.S. DOE, 2003b.

Petroleum exports include heavy products such as residual fuel oil and petroleum coke, which are produced as co-products with motor gasoline and other light products. Production of these heavier products often exceeds U.S. demand, and foreign demand absorbs the excess. Petroleum coke is the leading petroleum export product, accounting for 35 percent of petroleum exports in 2002, followed by residual fuel oil (18 percent of exports) and motor gasoline (almost 13 percent) (U.S. DOE, 2003b). Exports generally reflect foreign demand, but other factors influence exports as well. For example, exports of motor gasoline increased due to high prices in Europe at the time of the 1990 Persian Gulf war. U.S. refiners and marketers have gained experience in marketing to diverse world markets, and U.S. products are now sold widely abroad (U.S. DOE, 1997). As reported by the International Trade Administration and shown in Figure B2C-9, the real value of petroleum exports has fluctuated between $5 and $10 billion during the years 1989 and 2002.

B2C-4 FINANCIAL CONDITION AND PERFORMANCE

The financial performance and condition of the Petroleum Refining segment are important determinants of its ability to withstand the costs of regulatory compliance without material adverse economic/financial impact. To provide insight into the industry's financial performance and condition, EPA reviewed two key measures of financial performance over the 12-year period, 1992-2003: net profit margin and return on total capital. EPA calculated these measures as a revenue-weighted index of measure values for public reporting firms in the respective industries, using data from the Value Line Investment Survey. Financial performance in the most recent financial reporting period (2003) is obviously not a perfect indicator of conditions at the time of regulatory compliance. However, examining the trend, and deviation from the trend, through the most recent reporting period gives insight into where the industry *may be*, in terms of financial performance and condition, at the time of compliance. In addition, the volatility of performance against the trend, in itself, provides a measure of the *potential* risk faced by the industry in a future period in which compliance requirements are faced: all else equal, the more volatile the historical performance, the more likely the industry *may* be in a period of relatively weak financial conditions at the time of compliance.

Net profit margin is calculated as after-tax income before nonrecurring gains and losses as a percentage of sales or revenue, and measures profitability, as reflected in the conventional accounting concept of net income. Over time, the firms in an industry, and the industry collectively, must generate a sufficient positive profit margin if the industry is to remain economically viable and attract capital. Year-to-year fluctuations in profit margin stem from several factors, including: variations in aggregate economic conditions (including international and U.S. conditions), variations in industry-specific market conditions (e.g., short-term capacity expansion resulting in overcapacity), or changes in the pricing and availability of inputs to the industry's production processes (e.g., the cost of energy to the petroleum refining process). The extent to which these fluctuations affect an industry's profitability, in turn, depends heavily on the fixed vs. variable cost structure of the industry's operations. In a capital intensive industry such as Petroleum Refining, the relatively high fixed capital costs as well as other fixed overhead outlays, can cause even small fluctuations in output or prices to have a large positive or negative affect on profit margin.

Return on total capital is calculated as annual net profit, plus one-half of annual long-term interest, divided by the total of shareholders' equity and long-term debt (total capital). This concept measures the total productivity of the capital deployed by a firm or industry, regardless of the financial source of the capital (i.e., equity, debt, or liability element). As such, the return on total capital provides insight into the profitability of a business' assets independent of financial structure and is thus a "purer" indicator of asset profitability than return on equity. In the same way as described for *net profit margin*, the firms in an industry, and the industry collectively, must generate, over time, a sufficient return on capital if the industry is to remain economically viable and attract capital. The factors causing short-term variation in *net profit margin* will also be the primary sources of short-term variation in *return on total capital*.

Figure B2C-10 below shows trends in net profit margins and return on total capital for the Petroleum Refining segment between 1992 and 2003. Through the first half of the 1990s, the petroleum industry was characterized by unusually low product margins, low profitability, and substantial restructuring. These low profit margins resulted from three cost-side factors – (1) increases in operating costs as a result of governmental regulations; (2) expensive upgrading of processing units to accommodate lower-quality crude oils;[7] and (3) upgrading of operations to adapt to changes in demand for refinery products[8] – coupled with lower product prices, resulting from competitive pressures (API, 1999). In the late 1990s, the petroleum industry pursued cost-cutting measures throughout their operations (Rodekohr, 1999)[9]. These cost-cutting measures, along with increases in the prices of

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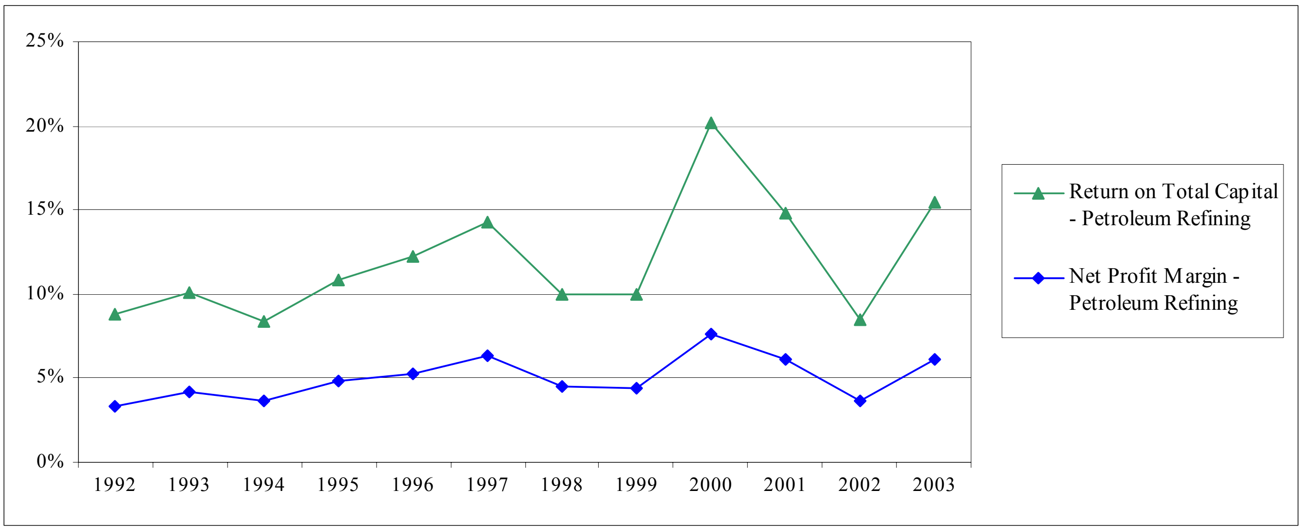
[7]Crude oils processed by U.S. refineries have become heavier and more contaminated with materials such as sulfur. This trend reflects reduced U.S. dependence on the more expensive high gravity ("light") and low sulfur ("sweet") crude oils produced in the Middle East, and greater reliance on crude oil from Latin America (especially Mexico and Venezuela), which is relatively heavy and contains higher sulfur ("sour") (U.S. DOE, 1999a).

[8]Demand for lighter products such as gasoline and diesel fuel has increased, and demand for heavier products has decreased.

[9]Reductions in costs resulted from:
- divesting marginal refineries and gasoline outlets;
- divesting less profitable activities (e.g., gasoline credit cards);
- reducing corporate overhead costs, including eliminating redundancies through restructuring;
- outsourcing some administrative activities; and
- use of new technologies requiring less labor.

petroleum refining products, resulted in significantly improved financial performance in the Petroleum Refining segment. Refinery profits remained high in 2000 and the first half of 2001, due to low product inventories and high operating rates. The latter half of 2001 and 2002 saw the effects of the global recession, the attacks of 9/11, and a mild winter. These factors, coupled with world supply in excess of demand, led to decreases in refiner margins, as crude oil prices increases and petroleum product prices decreased. In 2003, as the U.S. economy began recovery from its economic weakness, the domestic Petroleum Refining segment returned to relatively strong financial performance.

Figure B2C-10: Net Profit Margin and Return on Total Capital for Petroleum Refining



Source: Value Line 1999-2003

B2C-5 FACILITIES OPERATING COOLING WATER INTAKE STRUCTURES

Section 316(b) of the Clean Water Act applies to point source facilities that use, or propose to use, a cooling water intake structure that withdraws cooling water directly from a surface waterbody of the United States. In 1982, the Petroleum and Coal Products industry (SIC 29) withdrew 590 billion gallons of cooling water, accounting for approximately 0.8 percent of total industrial cooling water intake in the United States[10]. The industry ranked 4th in industrial cooling water use, behind the electric power generation industry and the chemical and primary metals industries (1982 Census of Manufactures).

This section provides information for facilities in the petroleum segment potentially subject to the proposed regulation. Existing facilities that meet all of the following conditions are potentially subject to the proposed regulation:[11]

- 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

[10] Data on cooling water use are from the *1982 Census of Manufactures*. 1982 was the last year in which the Census of Manufactures reported cooling water use.

[11] The proposed Phase III regulation also applies to existing electric generating facilities as well as certain facilities in the oil and gas extraction industry and the seafood processing industry. See Chapters B4 and B5 and Part C of this document for more information on these industries.

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;

- Have a National Pollutant Discharge Elimination System (NPDES) permit or are required to obtain one; and
- Have a design intake flow of greater than 2 million gallons per day (MGD).

The proposed Phase III regulation also covers substantial additions or modifications to operations undertaken at such facilities. While all facilities that meet these criteria are potentially subject to the regulation, this section focuses on the 36 facilities nation-wide in the petroleum segment identified in EPA's 2000 Section 316(b) Industry Survey as being potentially subject to the proposed regulation[12]. Information collected in the Detailed Industry Questionnaire found that an estimated 36 of 163 Petroleum Refining facilities, or 22 percent, meet the characteristics of a potential Phase III facility.

B2C-5.1 Waterbody and Cooling System Type

Table B2C-10 shows the distribution of existing Section 316(b) Petroleum Refineries by type of water body and cooling system. Twenty-six facilities, or 74 percent, obtain their cooling water from either a freshwater stream or a river. Five facilities (14 percent) of refineries obtain their cooling water from either an estuary or a tidal river. Two facilities, or 6 percent, obtain their cooling water from a Great Lake. The other two sources of cooling water reported for Petroleum Refineries were oceans and lakes/reservoirs, accounting for three percent each.

The most common cooling water system used by Petroleum Refineries is a recirculating cooling system, representing approximately 53 percent of all systems used by refineries. Thirty-one percent of all refineries use a combination cooling system. The remaining 14 percent use a once-through cooling system. Of the five plants that withdraw from an estuary, the most sensitive type of waterbody, two use a once-through system. Plants with once-through cooling water systems withdraw between 70 and 98 percent more water than those with recirculating systems.

Table B2C-10: Number of Section 316(b) Petroleum Refining Facilities by Water Body Type and Cooling System Type

Water Body Type	Cooling System						Total
	Recirculating		Combination		Once-Through		
	Number	% of Total	Number	% of Total	Number	% of Total	
Estuary/ Tidal River	0	0%	3	60%	2	40%	5
Ocean	0	0%	0	0%	1	100%	1
Lake/ Reservoir	1	100%	0	0%	0	0%	1
Freshwater Stream/ River	18	69%	6	23%	2	8%	26
Great Lake	0	0%	2	100%	0	0%	2
Total[a]	***19***	***53%***	***11***	***31%***	***5***	***14%***	***36***

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

Source: U.S. EPA, 2000.

[12] EPA applied sample weights to the sampled 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).

According to the American Petroleum Institute and EPA, water use at Petroleum Refineries has been declining because facilities are increasing their reuse of water (U.S. EPA, 1996a).

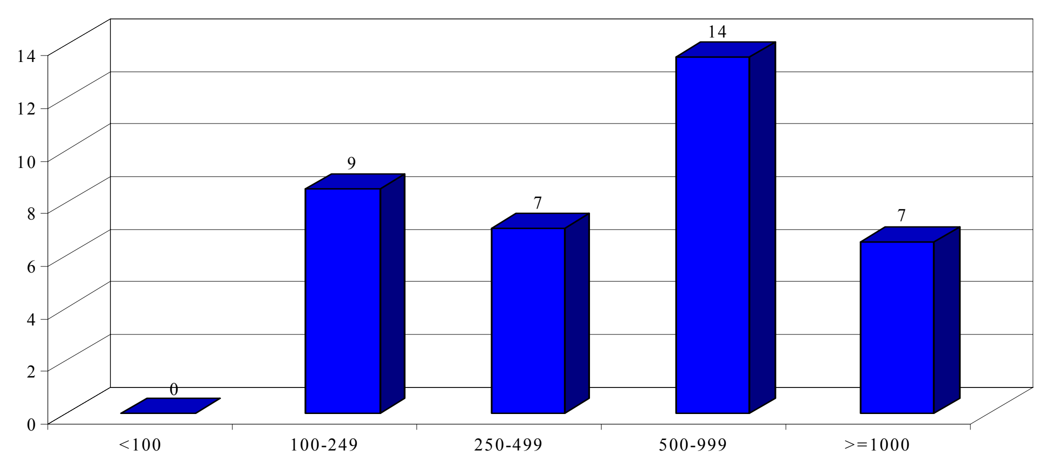
B2C-5.2 Facility Size

Section 316(b) sample facilities are larger than facilities in the petroleum refining industry as a whole, as reported in the Census and discussed previously:

- Forty percent of all facilities in the refineries segment had fewer than 100 employees in 1992; none of the potential Phase III facilities in that segment fall into that employment category.

Figure B2C-11 shows the number of potential Phase III facilities by employment size category.

Figure B2C-11: Number of Section 316(b) Petroleum Refineries by Employment Size Category



Source: U.S. EPA, 2000.

B2C-5.3 Firm Size

EPA used the Small Business Administration (SBA) small entity thresholds to determine the number of existing Section 316(b) petroleum refineries owned by small firms. Firms in this industry are considered small if they employ fewer than 1,500 people. Table B2C-11 shows that all of the Section 316(b) Petroleum Refineries are owned by large firms.

Table B2C-11: Number of Section 316(b) Petroleum Refineries by Firm Size

SIC	Large		Small		Total
	No.	% of SIC	No.	% of SIC	
2911	36	100%	0	0%	36

Source: U.S. EPA, 2000; U.S. SBA, 2000; D&B, 2001.

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Chapter B2D: Steel (SIC 331)

EPA's *Detailed Industry Questionnaire,* hereafter referred to as the DQ, identified five 4-digit SIC codes in the Steel Works, Blast Furnaces, and Rolling and Finishing Mills Industries (SIC 331) with at least one existing facility that operates a CWIS, holds a NPDES permit, withdraws equal to or greater than two million gallons per day (MGD) from a water of the United States, and uses at least 25 percent of its intake flow for cooling purposes (facilities with these characteristics are hereafter referred to as facilities potentially subject to the Phase III regulation or "potential Phase III facilities").

For each of the five SIC codes, Table B2D-1 below provides a description of the industry segment, a list of primary products manufactured, the total number of detailed questionnaire respondents (weighted to represent national results), and the number and percent of potential Phase III facilities within the estimated national total of facilities in the respective industry SIC code groups.

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Table B2D-1: Potential Phase III facilities in the Steel Industry (SIC 331)

SIC	SIC Description	Important Products Manufactured	Number of Facilities[a]		
			Total	Potential Phase III facilities [b]	%
Steel Mills (SIC 3312)					
3312	Steel Works, Blast Furnaces (Including Coke Ovens), and Rolling Mills	Hot metal, pig iron, and silvery pig iron from iron ore and iron and steel scrap; converting pig iron, scrap iron, and scrap steel into steel; hot-rolling iron and steel into basic shapes, such as plates, sheets, strips, rods, bars, and tubing; merchant blast furnaces and byproduct or beehive coke ovens	***161***	***46***	***28.6%***
Steel Products (SICs 3315, 3316, 3317)					
3315	Steel Wiredrawing and Steel Nails and Spikes	Drawing wire from purchased iron or steel rods, bars, or wire; further manufacture of products made from wire; steel nails and spikes from purchased materials	122	7	5.7%
3316	Cold-Rolled Steel Sheet, Strip, and Bars	Cold-rolling steel sheets and strip from purchased hot-rolled sheets; cold-drawing steel bars and steel shapes from hot-rolled steel bars; producing other cold finished steel	57	10	17.5%
3317	Steel Pipe and Tubes	Production of welded or seamless steel pipe and tubes and heavy riveted steel pipe from purchased materials	130	5	3.8%
		Total Steel Products	***309***	***21***	***6.8%***

Table B2D-1: Potential Phase III facilities in the Steel Industry (SIC 331)

SIC	SIC Description	Important Products Manufactured	Number of Facilities[a]		
			Total	**Potential Phase III facilities [b]**	**%**
Other Segments					
3313	Electrometallurgical Products, Except Steel	Ferro and nonferrous metal additive alloys by electrometallurgical or metallothermic processes, including high percentage ferroalloys and high percentage nonferrous additive alloys	***6***	***2***	***33.3%***
Total Steel (SIC 331)					
		Total SIC Code 331	**476**	**68**	**14.3%**

[a] Number of weighted detailed questionnaire survey respondents.
[b] Individual numbers may not add up due to independent rounding.

Source: U.S. EPA, 2000; Executive Office of the President, 1987

The table shows that an estimated 68 out of 476 facilities (or 14 percent) in the Steel Industry (SIC 331) are potentially subject to this proposed regulation. EPA also estimated the percentage of total production that occurs at facilities potentially subject to the proposed regulation. Total value of shipments for the steel industry from the 1998 Annual Survey of Manufacturers is $76.2 billion. Value of shipments, a measure of the dollar value of production, was selected for the basis of this estimate. Because value of shipments data were not collected using the DQ, these data were not available for the sample of Phase III manufacturing facilities potentially subject to the proposed regulation. Total revenue, as reported on the DQ, was used a close approximation for value of shipments for these facilities. EPA estimated the total revenue of facilities in the steel industry subject to the proposed regulation is $38.4 billion. Therefore, EPA estimates that 50 percent of total production in the steel industry occurs at facilities potentially subject to the proposed regulation.

The responses to the Detailed Questionnaire indicate that two main steel segments account for the largest numbers of potential Phase III facilities: (1) Steel Mills (SIC code 3312) and (2) Steel Products (SIC codes 3315, 3316, and 3317). Of the 70 potential Phase III facilities in the steel industry, 46, or 66 percent, are Steel Mills, and 22, or 32 percent, are Steel Products facilities. The remainder of the steel industry profile therefore focuses on these two industry segments

Table B2D-2 provides the cross-walk between SIC codes and the new NAICS codes for the profiled steel SIC codes. The table shows that both cold finishing of steel shapes (SIC 3316) and steel pipe and tubes (SIC 3317) have a one-to-one relationship to NAICS codes. The other SIC codes in the profiled steel segments correspond to two NAICS codes.

Table B2D-2: Relationships between SIC and NAICS Codes for the Steel Industries (1997)

SIC Code	SIC Description	NAICS Code	NAICS Description	Number of Establishments	Value of Shipments ($1000)	Employment
3312	Blast furnaces and steel mills	324199	All other petroleum and coal products manufacturing (pt)	8	438,107	1,731
	Blast furnaces and steel mills	331111	Iron and steel mills (pt)	193	56,358,764	144,074
3313	Electrometallurgical products	331112	Electrometallurgical ferroalloy product manufacturing	24	1,409,834	3,724
	Electrometallurgical products	331492	Secondary smelting, refining, and alloying of nonferrous metal (except copper and aluminum) (pt)	4	125,945	311
3315	Steel wire and related products	331222	Steel wire drawing	273	4,920,798	23,489
	Steel wire and related products	332618	Other fabricated wire product manufacturing (pt)	31	370,492	2,265
3316	Cold finishing of steel shapes	331221	Cold-rolled steel shape manufacturing	186	6,343,466	14,362
3317	Steel pipe and tubes	331210	Iron and steel pipes and tubes manufacturing from purchased steel	235	7,565,377	27,723

Source: *U.S. DOC, 1997*

B2D-1 SUMMARY INSIGHTS FROM THIS PROFILE

A key purpose of this profile is to provide insight into the ability of steel industry firms that would be subject to the 316(b) regulation to absorb compliance costs without material adverse economic/financial effects. Two important factors in the ability of the industry's ability to withstand compliance costs are: (1) the extent to which the industry may be expected to shift compliance costs to its customers through price increases and (2) the financial health of the industry and its general business outlook.

Likely Ability to Pass Compliance Costs Through to Customers
As reported in the following sections of this profile, the steel industry is relatively unconcentrated, which would suggest that firms in this industry would have difficulty in passing through to customers a significant portion of their compliance-related costs. In addition, the domestic steel industry faces high competition from imports into the U.S. market, further curtailing the potential of firms in this industry to pass through to customers a significant portion of their compliance-related costs. As discussed above, the proportion of total value of shipments in the industry potentially subject to the proposed regulation is 50 percent. The actual proportion of total value of shipments subject to regulation-induced compliance costs would be smaller since not all of the facilities would be subject to the national categorical requirements of the proposed regulation: that is, facilities below the proposed design intake flow (DIF) would be subject to permitting based on best professional judgement (BPJ) rather than based on national standards, and several facilities currently employ baseline technologies that meet the requirements of the proposed regulation. Given the likelihood that these percentages represent upper bound estimates, EPA believes that the theoretical threshold for justifying the use of industry-wide CPT rates in the impact analysis of existing Phase III steel facilities has not been met. For these reasons, in its analysis of regulatory impacts for the steel industry, EPA assumed that complying firms would be unable to pass compliance costs through to customers: i.e., complying facilities must absorb all compliance costs within their financial

condition at the time of compliance (see following sections and Appendix 3 to *Chapter B3: Economic Impact Analysis for Manufacturers* for further information).

Financial Health and General Business Outlook
Over the past decade, the steel industry, like other U.S. manufacturing industries, experienced a range of economic/financial conditions, including substantial challenges. The U.S. steel industry went through a difficult restructuring process in the 1980s and early 1990s, including the closing of a number of inefficient mills, substantial investment in new technologies, and reductions in the labor force. Although U.S. demand for steel was strong in the late 1990s, low-priced imports increased substantially in 1998, which caused a number of U.S. steel bankruptcies and steelworker layoffs. The increased imports resulted from the Asian financial crisis, with the associated decline in Asian demand for steel and currency devaluations. Tariffs provided temporary relief through 2002; however, all tariffs were removed by the end of 2003. The steel industry was also negatively affected by economic recession in 2000 and 2001 and has been slow to recover. The industry has weathered difficult periods over the past few years and may be in position for better performance with continued strengthening of the U.S. economy. However, until such improvement manifests more concretely, the industry's relatively weak financial condition suggest a lower ability (among the industries subject to the 316(b) regulation) to withstand additional regulatory compliance costs without imposing significant financial impacts.

B2D-2 DOMESTIC PRODUCTION

Steel is one of the most important products of the U.S. industrial metals industry. For most of the twentieth century, the U.S. steel industry consisted of a few large companies utilizing an integrated steelmaking process to produce the raw steel used in a variety of commodity steel products. The integrated process requires a large capital investment to process coal, iron ore, limestone, and other raw materials into molten iron, which is then transformed into finished steel products (S&P, 2001). In recent decades, the integrated steel industry has undergone a dramatic downsizing as a result of increased steel imports, decreased consumption by the auto industry, and the advent of "minimills" (S&P, 2001)[1]. While the traditional integrated facilities using basic oxygen furnaces (BOF) still account for a substantial percent of U.S. steel mill product production, the share of electric arc furnace (EAF) facilities using scrap steel as an input has grown steadily[2]. By 2002, about 72 companies operating about 107 steelmaking plants used the EAF steelmaking process; these non-integrated, minimill facilities produced 46.1 million metric tons of steel, an increase of about eight percent compared with that of 2001, and accounted for 50.4 percent of total steelmaking (USGS, 2002). The range of products produced by EAFs has also expanded over time. Initially, EAFs produced primarily lower-quality structural materials. Starting in the 1990s, EAFs began producing higher quality sheet products as well. All recent capacity additions have been at EAF facilities.

Basic steel mill products include carbon steel, steel alloys, and stainless steel. Steel forming and finishing operations may take place at facilities co-located with steelmaking or at separate facilities. These operations take steel (in the form of blooms, billets, and slabs) and use heating, rolling or drawing, pickling, cleaning, galvanizing, and electroplating processes in various combinations to produce finished bars, wire, sheets, and coils (semifinished steel products). Establishments that produce hot rolled products, along with basic BOF and EAF steelmaking facilities, are included in SIC 3312. SIC codes 3315, 3316, and 3317 perform additional processing of steel bars, wires, sheets, and coils (including cold-rolling of sheets) to produce steel products for a variety of end-uses (U.S. EPA, 1995).

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[1] Large integrated producers include such companies as Bethlehem Steel, LTV, and U.S. Steel. Nucor is the largest U.S. minimill producer.

[2] Production from open hearth furnaces, which dominated production until the early 1950s, ended in 1991. BOF facilities have traditionally been referred to as integrated producers, because they combined iron-making from coke, production of pig iron in a blast furnace, and production of steel in the BOF. In recent years, some facilities have closed their coke ovens. These BOF facilities are no longer fully integrated.

The steel industry is the fourth largest energy-consuming industry in the U.S. economy. Energy costs account for approximately 17 percent of the total manufacturing cost (AISI 2000). Steelmakers use coal, oil, electricity, and natural gas to fire furnaces and run process equipment. Minimill producers require large quantities of electricity to operate the electric arc furnaces used to melt and refine scrap metal, while integrated steelmakers depend on coal for up to 60 percent of their total energy requirements (McGraw-Hill, 1998).

B2D-2.1 Output

Steel mill products are sold to service centers (which buy finished steel, often process it further, and sell to a variety of fabricators, manufacturers, and construction industry clients), to vehicle producers, and to the construction industry. The rapid growth in sales of heavy sports utility vehicles contributed to increased U.S. steel consumption in the 1990s. Efforts to increase the fuel efficiency of vehicles has eroded steel's position in the automotive market as a whole, however, as aluminum and plastic have replaced steel in many automotive applications. Other end-uses for steel include a wide range of agricultural, industrial, appliance, transportation, and container applications. Use of steel in beverage cans has been largely replaced by aluminum.

Table B2D-3 shows trends in production from the two major groups of steel producers: BOF and EAF facilities.

Table B2D-3: U.S. Steel Production by Type of Producer

Year	Steel Production		Percent from BOF	Percent from EAF
	Million MT	% Change		
1990[a]	89.7	n/a	59.1%	37.3%
1991[b]	79.7	-11.1%	60.0%	38.4%
1992	84.3	5.8%	62.0%	38.0%
1993	88.8	5.3%	60.6%	39.4%
1994	91.2	2.7%	60.7%	39.3%
1995	95.2	4.4%	59.6%	40.4%
1996	95.5	0.3%	57.4%	42.6%
1997	98.5	3.1%	56.2%	43.8%
1998	98.6	0.1%	54.9%	45.1%
1999	97.4	-1.2%	53.7%	46.3%
2000	102	4.7%	53.0%	47.0%
2001	90.1	-11.7%	52.6%	47.4%
2002	91.6	1.7%	49.6%	50.4%
2003[c]	91.5	-0.1%	48.0%	52.0%
Total Percent Change 1990-2003	2.0%			
Average Annual Growth Rate change	0.2%			

[a] 3.5 percent of 1990 production was from open hearth furnaces.
[b] 1.6 percent of 1991 production was from open hearth furnaces.
[c] Estimated.

Source: AISI, 2001b; USGS, 2000; USGS, 1997; USGS 2004; USGS, Iron and Steel Statistical Compendium.

This table shows the cyclical nature of the U.S. steel industry, with variations in growth from year to year reflecting general U.S. and world economic conditions, persistent excess production capacity worldwide, the competitive strength of imports, and trends in steel's share of the automotive and other end-use markets for steel. The U.S. steel industry went through a difficult restructuring process in the 1980s and early 1990s, including the closing of a number of inefficient mills, substantial investment in new technologies, and reductions in the labor force. The U.S. became a world leader in low-cost production, lead by the minimill producers. Although U.S. demand for steel was strong in the late 1990s, low-priced imports increased substantially in 1998, which led to a number of U.S. steel bankruptcies and steelworker layoffs. The increased imports resulted from the Asian financial crisis, with the associated decline in Asian demand for steel and currency devaluations. The U.S. government initiated the Steel Action Program in response to the crisis, focusing on strong enforcement of trade laws through the World Trade Organization and bilateral efforts to address market-distorting practices abroad[3]. The industry began to show signs of recovery in the second half of 1999, and by early 2000 capacity utilization recovered to above 90 percent and earnings were up for most major steel companies (U.S. DOC, 2000). However, beginning in 2000, the weakening of the U.S. economy significantly reduced steel demand and total U.S. steel production fell by nearly 12 percent in 2001. In March 2002, the U.S. steel industry received temporary relief under Section 201 of the 1974 Trade Act with 3 years of tariffs ranging up to 30 percent on certain steel imports. Relief from imports was nullified to some extent when the U.S. Department of Commerce exempted 727 imported steel products from the tariff in June 2002. By year end, 2002 was the fourth highest steel import year in U.S. history. (USGS, 2002). Removal of all tariffs occurred on December 4, 2003. (S&P, 2004).

The steel industry is recovering, but slowly, from the import penetration in the late 90's followed by the economic recession in 2001. In 2003, the integrated steel industry had poor operating results, as high raw material costs outweighed increased sales and higher volumes. As a result, most domestic steel producers instituted a raw material surcharge to offset sharply rising costs for raw materials such as scrap, iron ore and coke. Additionally, worldwide capacity remains in excess of long-term needs. Imports will most likely rise in 2004 after the removal of tariffs. However, to the extent that imports put downward pressure on prices, they may force the shutdown of marginal capacity currently operating. These capacity reductions will reduce domestic supply, and may set the stage for better financial performance in later years (S&P, 2004).

Value of shipments and ***value added*** are two common measures of manufacturing output[4]. They provide insight into the overall economic health and outlook for an industry. Value of shipments is the sum of the receipts a manufacturer earns from the sale of its outputs; it indicates the overall size of a market or the size of a firm in relation to its market or competitors. Value added measures the value of production activity in a particular industry. It is the difference between the value of shipments and the value of inputs used to make the products sold.

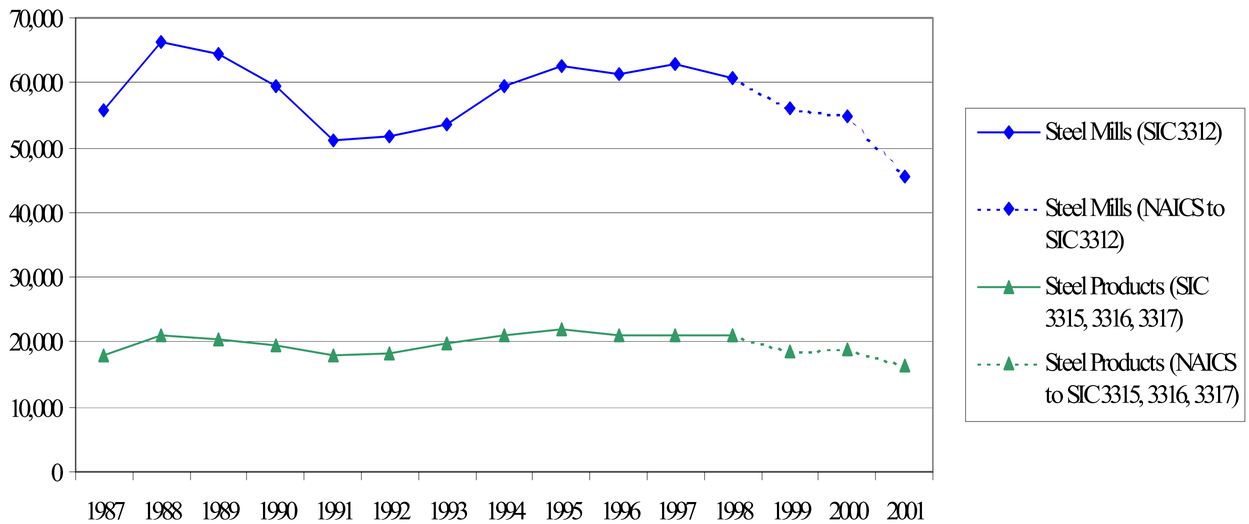
Figure B2D-1 presents trends in constant-dollar value of shipments and value added for Steel Mills and Steel Products. Value of shipments and value added from Steel Mills declined in the early 1990s, and recovered through 1997, prior to the 1998 import crisis and the later U.S. economic recession. This segment continued to decline through 2001. Value of shipments and value added for Steel Products were less volatile, increasing gradually over the period 1990 through 1997. Value added stayed relatively constant through 2001, while value of shipments slightly declined.

[3] World steel trade is characterized by noncompetitive practices in a number of countries, which have resulted in substantial friction over trade issues since the late 1960s. Since 1980, almost 40 percent of the unfair trade practice cases investigated in the U.S. have been related to steel products (U.S. DOC, 2000).

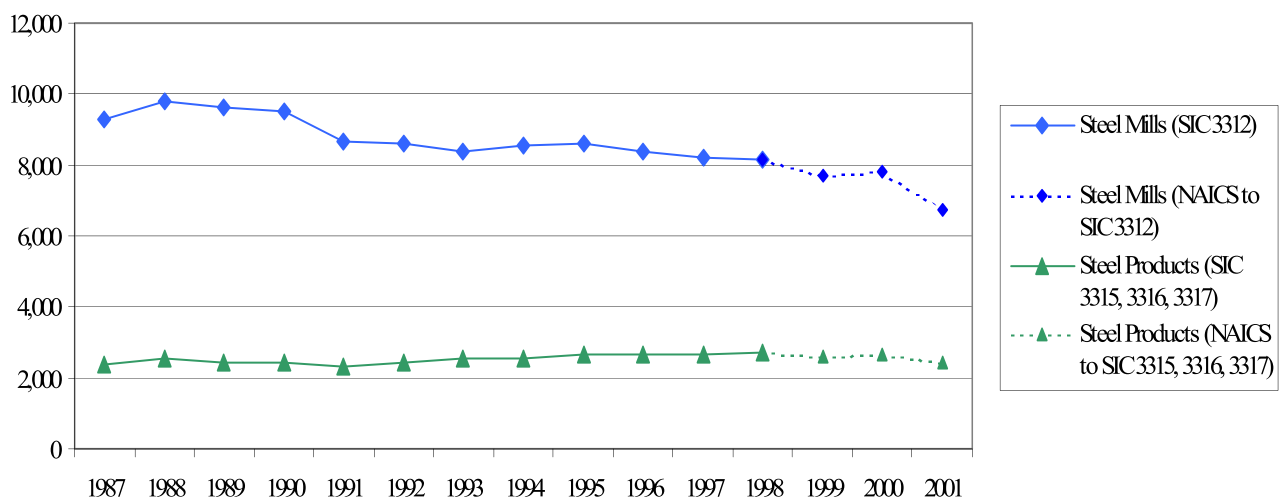
[4] Terms highlighted in bold and italic font are further explained in the glossary.

Figure B2D-1: Value of Shipments and Value Added for Profiled Steel Industry Segments (millions,$2003)

Value of Shipments



Value Added



[a] Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

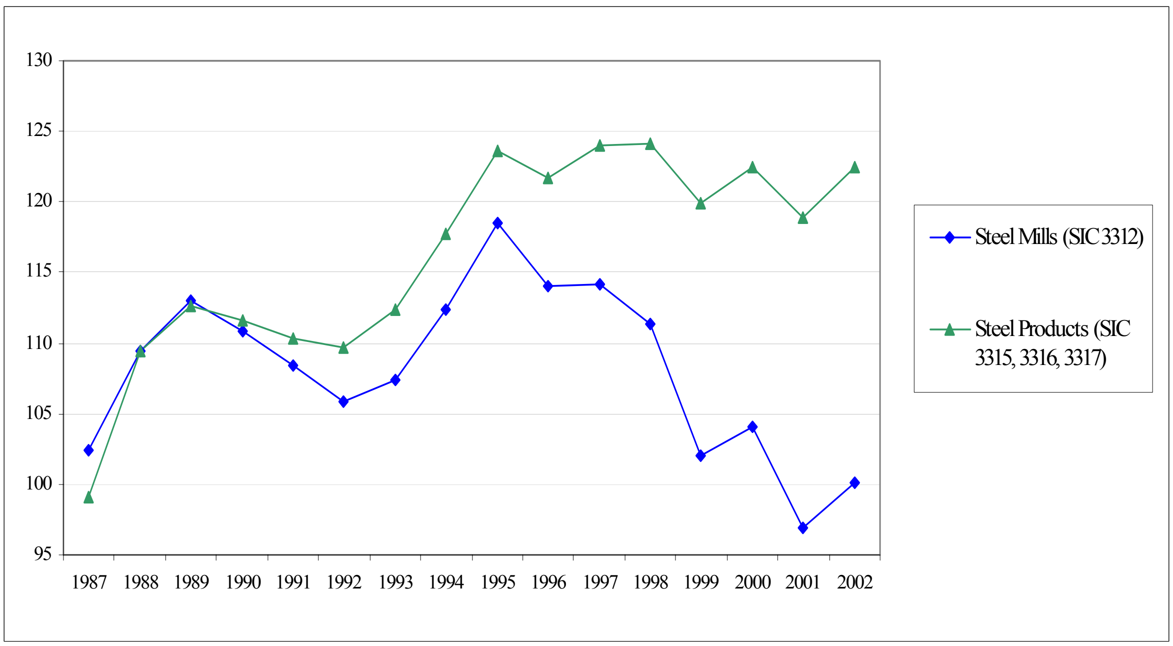
Source: U.S. DOC, 1988-1991, 1993-1996 and 1998-2001; US. DOC, 1987, 1992, 1997.

B2D-2.2 Prices

The ***producer price index*** (PPI) measures price changes, by segment, from the perspective of the seller, and indicates the overall trend of product pricing, and thus supply-demand conditions, within a segment.

Figure B2D-2 below shows that prices increased from 1987 to 1989 and then decreased in the early 1990s, due to a depressed domestic economy and the resulting decline in the demand for steel. Prices rebounded sharply through 1995 before eroding again, due to the global oversupply and increases in exports discussed above. Basic steel prices declined sharply with the growth of imports in the late 1990s, recovered in 2000, but dropped again in 2001with the decline in steel demand (S&P, 2001; AISI, 2001a). Prices increased slightly in 2002 with the beginning of the economic recovery. The reason prices in the Steel Mill segment have declined since 1997, while prices in the Steel Products segment have remained constant, is most likely due to the advent of mini-mill technology, which lowers the cost of production and therefore lowers prices as well.

Figure B2D-2: Producer Price Index for Profiled Steel Industry Segments



Source: BLS, 2002.

B2D-2.3 Number of Facilities and Firms

The number of operating Steel Mills fluctuated significantly between 1989 and 2001, as the U.S. industry underwent a substantial restructuring. Table B2D-4 shows substantial decreases in the number of facilities in 1992 and 1993 due to a significant decrease in global demand for Steel Products and resulting overcapacity. This decrease was followed by a significant recovery in 1995 and 1996. The number of facilities continued to rise through 2001, with the largest increase around 1998. This increase could result in part from the advent of minimills discussed above. The import crisis in 1998 ultimately led to bankruptcy for a number of U.S. producers, including LTV and Bethlehem Steel (S&P, 2001). Additionally, 7 major bankruptcies occurred over 2002 and early 2003, including Bayou Steel Corp, Kentucky Electric Steel Inc, Slater Steel Inc, and Weirton Steel Corp. (USGS, 2004)

In contrast to the volatility in the number of Steel Mills, the number of facilities in the Steel Products segment has remained relatively stable for the past twelve years, with increases towards the end of the period.

Table B2D-4: Number of Facilities in the Profiled Steel Industry Segments

Year	Steel Mills		Steel Products	
	Number of Facilities	Percent Change	Number of Facilities	Percent Change
1989	476	n/a	784	n/a
1990	497	4.4%	776	-1.0%
1991	531	6.8%	807	4.0%
1992	412	-22.4%	831	3.0%
1993	343	-16.7%	833	0.2%
1994	339	-1.2%	804	-3.5%
1995	391	15.3%	791	-1.6%
1996	483	23.5%	770	-2.7%
1997	297	-38.5%	727	-5.6%
1998	346	16.5%	801	10.2%
1998[a]	398	34.0%	865	19.0%
1999[a]	685	72.1%	919	6.2%
2000[a]	981	43.2%	1,026	11.7%
2001[a]	1,352	37.9%	1,028	0.2%
Total Percent Change 1989-2001	*184.0%*		*10.3%*	
Average Annual Growth Rate	*9.1%*		*2.3%*	

[a] Before 1998, data were compiled in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census Bridge Between NAICS and SIC.

Source: U.S. SBA, 1989-2001.

The trend in the number of firms over the period between 1990 and 2001 is similar to the trend in the number of facilities in both industry segments. The number of firms in the Steel Mill segment decreased to a period-low of 216 in 1997, before increasing over the rest of the period. According to the American Iron and Steel Institute (AISI), 23 U.S. steel companies either declared bankruptcy or ceased operations entirely from 1997 through mid-2001, as a result of the continuing trade difficulties and weakness in the U.S. economy (AISI, 2001a). The number of firms in the Steel Products segment also decreased from 1992 to 1998, before rising steadily through 2001.

Table B2D-5 shows the number of firms in the two profiled steel segments between 1990 and 2001.

Table B2D-5: Number of Firms in the Profiled Steel Industry Segments

Year	Steel Mills		Steel Products	
	Number of Firms	Percent Change	Number of Firms	Percent Change
1990	408	n/a	597	n/a
1991	433	6.1%	635	6.4%
1992	321	-25.9%	661	4.1%
1993	261	-18.7%	641	-3.0%
1994	258	-1.1%	618	-3.6%
1995	309	19.8%	607	-1.8%
1996	397	28.5%	583	-4.0%
1997	216	-45.6%	544	-6.7%
1998	267	23.6%	601	10.5%
1998[a]	314	45.3%	666	22.4%
1999[a]	593	89.0%	716	7.4%
2000[a]	885	49.2%	810	13.2%
2001[a]	1,254	41.6%	811	0.1%
Total Percent Change 1990-2001	*207.4%*		*35.8%*	
Average Annual Growth Rate	*10.7%*		*2.8%*	

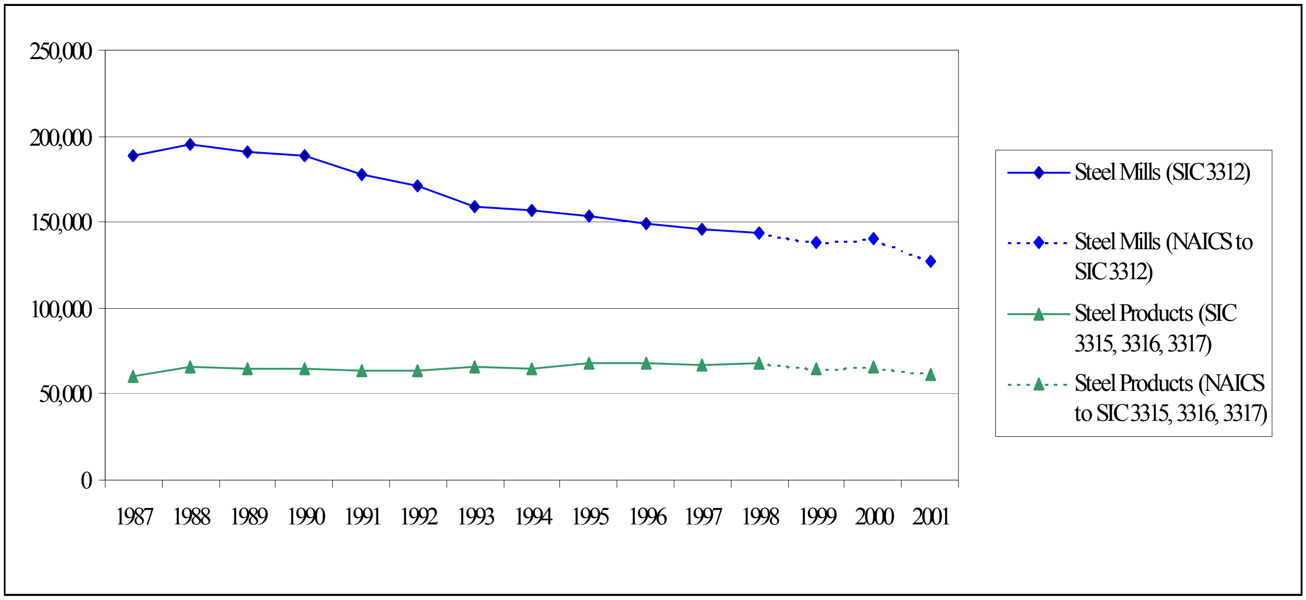
[a] Before 1998, data were compiled in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC.*

Source: U.S. SBA, 1989-2001.

B2D-2.4 Employment and Productivity

Figure B2D-3 below provides information on ***Employment*** from the Annual Survey of Manufactures for the Steel Mills and Steel Products segments. The figure shows that employment levels in the Steel Mills segment decreased by a total of 33 percent between 1987 and 2001. Employment is a significant cost component for steelmakers, accounting for approximately 30 percent of total costs (McGraw-Hill, 1998). Labor cost reductions enabled Steel Mills to improve profitability and competitiveness in the face of limited opportunity for price increase in the highly competitive market for Steel Products. The steady decline in employment reflects the smaller number of Steel Mill facilities and firms, in conjunction with aggressive efforts to improve worker productivity in order to cut labor costs and improve profits (McGraw-Hill, 1998). Employment declined further as a result of the 1998 import crisis, with almost 26,000 U.S. steelworkers reportedly losing their jobs (AISI, 2001a). Employment in the Steel Products segment over the period 1987-2001 has remained fairly constant.

Figure B2D-3: Employment for Profiled Steel Industry Segments



[a] Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

Source: U.S. DOC, 1988-1991, 1993-1996 and 1998-2001; U.S. DOC, 1987, 1992, 1997.

Table B2D-6 presents the change in value added per labor hour, a measure of ***labor productivity***, for the Steel Mill and Steel Products segments between 1987 and 2001. Labor productivity at Steel Mills increased slightly over this period. Value added per labor hour increased around seven percent between 1987 and 2001. Much of this increase in labor productivity can be attributed to the restructuring of the U.S. steel industry and the increased role of minimills in production. Minimills are capable of producing rolled steel from scrap with substantially lower labor needs than integrated mills (McGraw-Hill, 1998). Labor productivity in the Steel Products segment has also fluctuated, but increased nine percent overall from 1987 to 2001.

Table B2D-6: Productivity Trends for the Profiled Steel Industry Segments ($2003)

Year	Steel Mills				Steel Products			
	Value Added (millions)	Production Hours (millions)	Value Added/Hour ($/hr)	Value Added/Hour Percent Change	Value Added (millions)	Productio n Hours (millions)	Value Added/Hour ($/hr)	Value Added/Hour Percent Change
1987	9,269	306	30	n/a	2,355	108	22	n/a
1988	9,817	324	30	0%	2,550	94	27	24%
1989	9,631	348	28	-9%	2,447	112	22	-20%
1990	9,490	315	30	9%	2,445	93	26	21%
1991	8,682	279	31	3%	2,342	106	22	-17%
1992	8,605	277	31	0%	2,424	87	28	27%
1993	8,369	268	31	1%	2,551	109	23	-16%
1994	8,529	266	32	2%	2,572	91	28	21%
1995	8,604	263	33	2%	2,647	114	23	-18%
1996	8,389	260	32	-2%	2,645	134	20	-15%
1997	8,206	252	33	1%	2,645	110	24	21%
1998[a]	8,170	245	33	2%	2,702	113	24	0%
1999[a]	7,715	237	33	-2%	2,588	108	24	0%
2000[a]	7,836	241	32	0%	2,641	109	24	0%
2001[a]	6739	210	32	-1%	2427	100	24	0%
Total Percent Change 1987-2001	*-27.3%*	*-31.4%*	*6.7%*		*3.1%*	*-7.4%*	*9.1%*	
Average Annual Growth Rate	*-2.3%*	*-2.7%*	*0.5%*		*0.2%*	*-0.5%*	*0.6%*	

[a] Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

Source: U.S. DOC, 1988-1991, 1993-1996 and 1998-2001; U.S. DOC, 1987, 1992, and 1997.

B2D-2.5 Capital Expenditures

Steel production is a relatively capital intensive process. The integrated production process requires a capital investment of approximately $2,000 per ton of capacity for plants and equipment. The nonintegrated process employed in minimills is significantly less capital intensive with capital costs of approximately $500 per ton of capacity (McGraw-Hill, 1998).

New capital expenditures are needed to modernize, expand, and replace existing capacity to meet growing demand. Capital expenditures in the Steel Mills and the Steel Products segments between 1987 and 2001 are presented in Table B2D-7 below. The table shows that capital expenditures in both the Steel Products and the Steel Mills dropped significantly between 1987 and 2001. Capital outlays increased in the late 1980s and early 1990s, rising by a total of 131 percent from 1987 to 1991. This substantial increase coincides with the advent of thin slab casting, a technology that allowed minimills to compete in the market for flat rolled sheet steel. The significant decreases in capital expenditures by Steel Mills that followed this expansion reflects the bottoming out of the demand for Steel Products in the early 1990s. The recovery in capital expenditures in the mid 1990s reflected increased demand and higher utilization rates (McGraw-Hill, 1998). However, the import crisis of the late 1990s and later weakening of the U.S. economy put pressure on the domestic industry, and expenditures for new capacity have decreased steadily since 1997 (McGraw-Hill, 2000).

Table B2D-7: Capital Expenditures for the Profiled Steel Industry Segments (millions,$2003)

Year	Steel Mills		Steel Products	
	Capital Expenditures	Percent Change	Capital Expenditures	Percent Change
1987	1,761	n/a	783	n/a
1988	2,642	50.0%	597	-23.8%
1989	3,360	27.2%	678	13.6%
1990	3,307	-1.6%	677	-0.1%
1991	3,736	13.0%	482	-28.8%
1992	2,704	-27.6%	496	3.0%
1993	2,126	-21.4%	542	9.2%
1994	3,059	43.9%	626	15.4%
1995	3,156	3.2%	611	-2.4%
1996	3,173	0.5%	658	7.7%
1997	2,871	-9.5%	605	-8.0%
1998[a]	2,821	-1.7%	578	-4.5%
1999[a]	2,391	-15.2%	488	-15.6%
2000[a]	2,175	-9.0%	507	3.9%
2001[a]	1,378	-36.6%	437	-13.9%
Total Percent Change 1987-2001	*-21.7%*		*-44.2%*	
Average Annual Growth Rate	*-1.7%*		*-4.1%*	

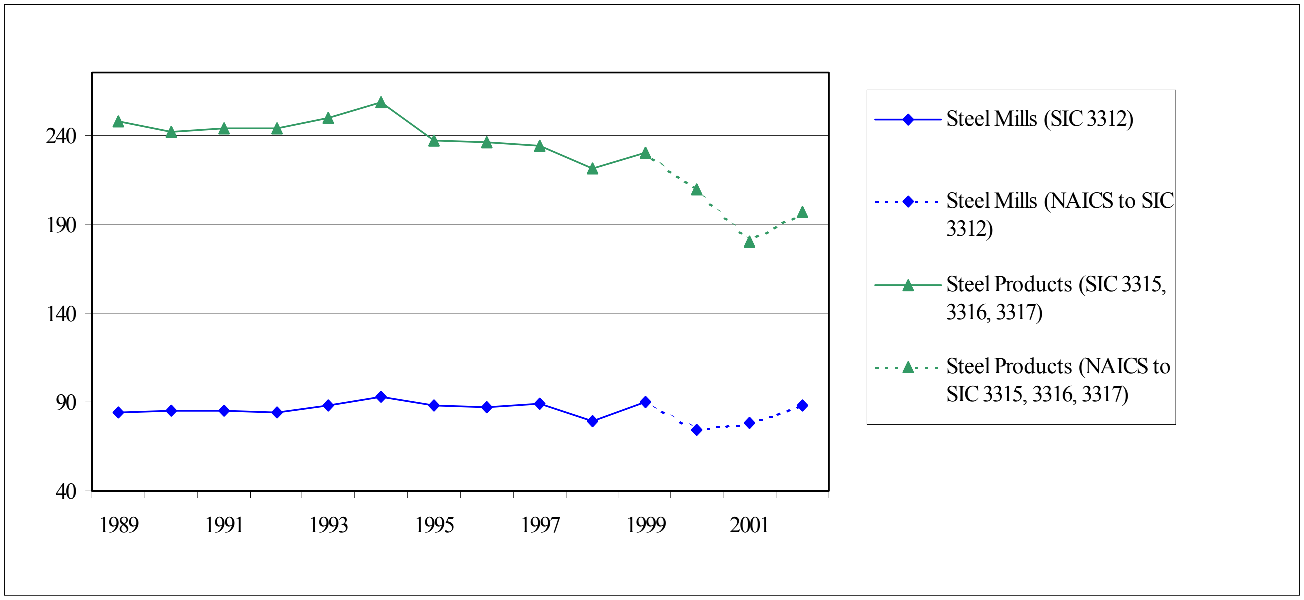
[a] Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

Source: U.S. DOC, 1988-1991, 1993-1996 and 1998-2001; U.S. DOC, 1987, 1992, and 1997.

B2D-2.6 Capacity Utilization

Capacity utilization measures actual output as a percentage of total potential output given the available capacity. Capacity utilization provides insight into the extent of excess or insufficient capacity in an industry, and into the likelihood of investment in new capacity. Figure B2D-4 presents the capacity utilization index from 1989 to 2002 for the 4-digit SIC codes that make up the Steel Mill and Steel Products segments. As shown in the figure, the index follows similar trends in each segment. For all segments, capacity utilization peaked in 1994 and decreased through 2001, with a slight increase in 2002. This trend reflects the over-capacity in the U.S. steel industry, which has followed the substantial capacity additions in the late 1980s and early 1990s and increased imports throughout the 1990s. Worldwide capacity remains in excess of long-term needs (S&P, 2004).

Figure B2D-4: Capacity Utilization Rates (Fourth Quarter) for Profiled Steel Industry Segments



[a] Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

Source: U.S. DOC, 1989-2001.

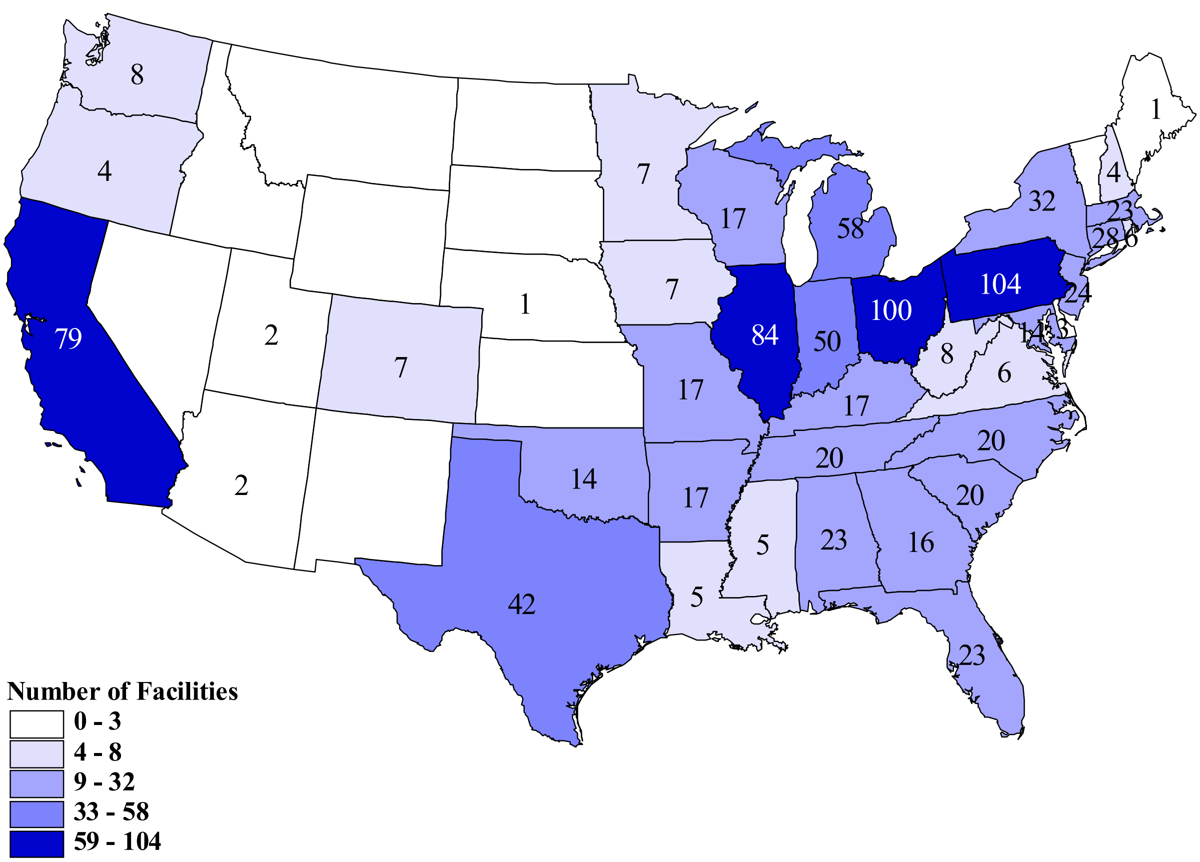
B2D-3 STRUCTURE AND COMPETITIVENESS

The companies that manufacture steel operate in a highly capital intensive industry. The Steel Mill segment is comprised of two different kinds of facilities, integrated mills and minimills. The integrated steelmaking process requires expensive plant and equipment purchases that will support production capacities ranging from two million to four million tons per year. Until the early 1960s, integrated steelmaking was the dominant method of U.S. steel manufacturing. Since then, the integrated steel business underwent dramatic downsizing due to competition from minimills and imports. These trends reduced the number of integrated steelmakers (S&P, 2001). Minimills vary in size, from capacities of 150,000 tons at small facilities to larger facilities with annual capacities of between 400,000 tons and two million tons. Integrated companies have significant capital costs of approximately $2,000 per ton of capacity compared with minimills' $500 per ton. Because minimills do not require as much investment in capital equipment as integrated steelmakers, minimills have been able to lower prices, driving integrated companies out of many of the commodity steel markets (S&P, 2001). The advent of minimills, with their lower initial capital investments, has made it easier for new producers to enter the market.

B2D-3.1 Geographic Distribution

Steel mills are primarily concentrated in the Great Lakes Region (New York, Pennsylvania, Ohio, Indiana, Illinois, and Michigan). In 2003, Indiana accounted for about 20 percent of total raw steel production, followed by Ohio, 15 percent, Michigan, seven percent, and Pennsylvania six percent (USGS, 2004). Historically, mill sites were selected for their proximity to water (both for transportation and for use in cooling and processing) and the sources of their raw materials, iron ore and coal. The geographic concentration of the industry has begun to change as minimills can be built anywhere where electricity and scrap are available at a reasonable cost and where a local market exists (U.S. EPA, 1995). Figure B2D-5 below shows the distribution of all facilities by State in both profiled steel segments (Steel Mills and Steel Products), based on the 1992 Census of Manufactures.[5]

Figure B2D-5: Geographical Distribution of Facilities in the Profiled Steel Industry Segments



Source: U.S. DOC, 1987, 1992, and 1997.

[5] The *1992 Census of Manufactures* is the most recent data available by SIC code and State.

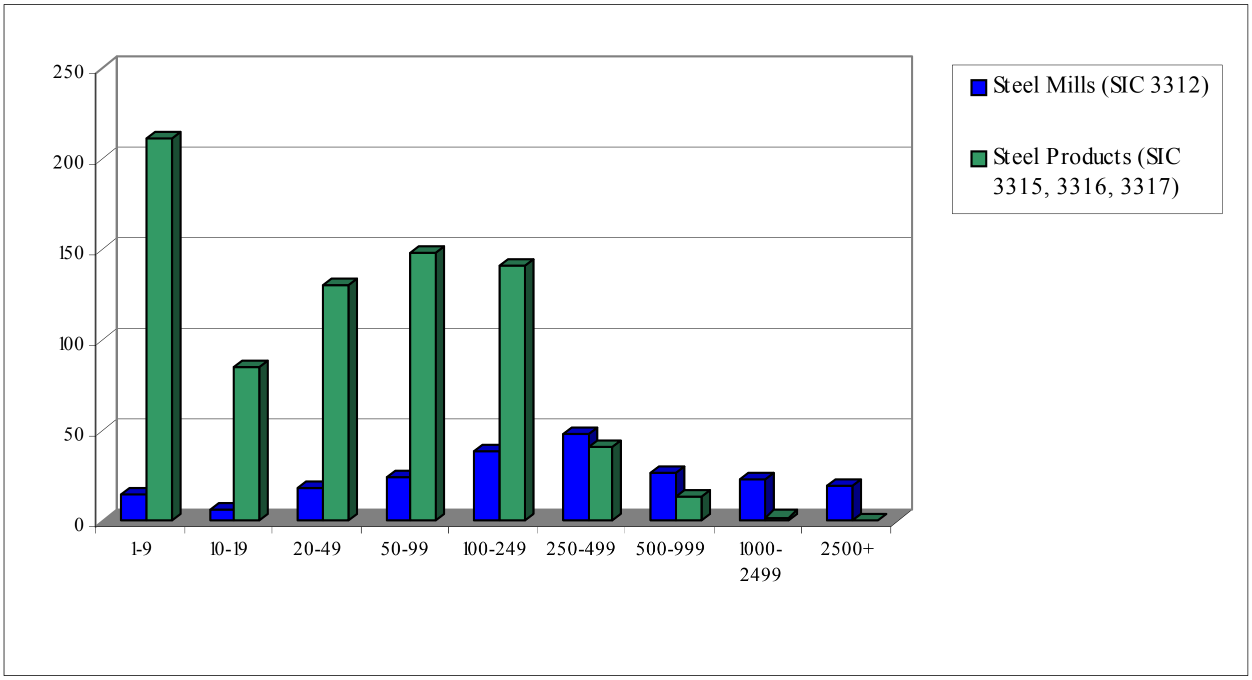
B2D-3.2 Facility Size

Seventy-one percent of all Steel Mills employed 100 or more employees in 1992, as shown in Figure B2D-6. These facilities accounted for approximately 98 percent of 1992 value of shipments. Facilities with more than 1,000 employees accounted for approximately 69 percent of all Steel Mill shipments. For 1997, Census of Manufactures data for Iron and Steel Mills (NAICS 331111), which is roughly comparable to the SIC 3312 data shown in Figure B2D-6, show that the 11 percent of facilities with more than 1,000 employees accounted for a somewhat smaller percentage, 63 percent, of total value of shipments. The declining share of total production in the largest facilities reflects growth in the minimill production segment, which, on average, have smaller capacity and lower employment than integrated mills.

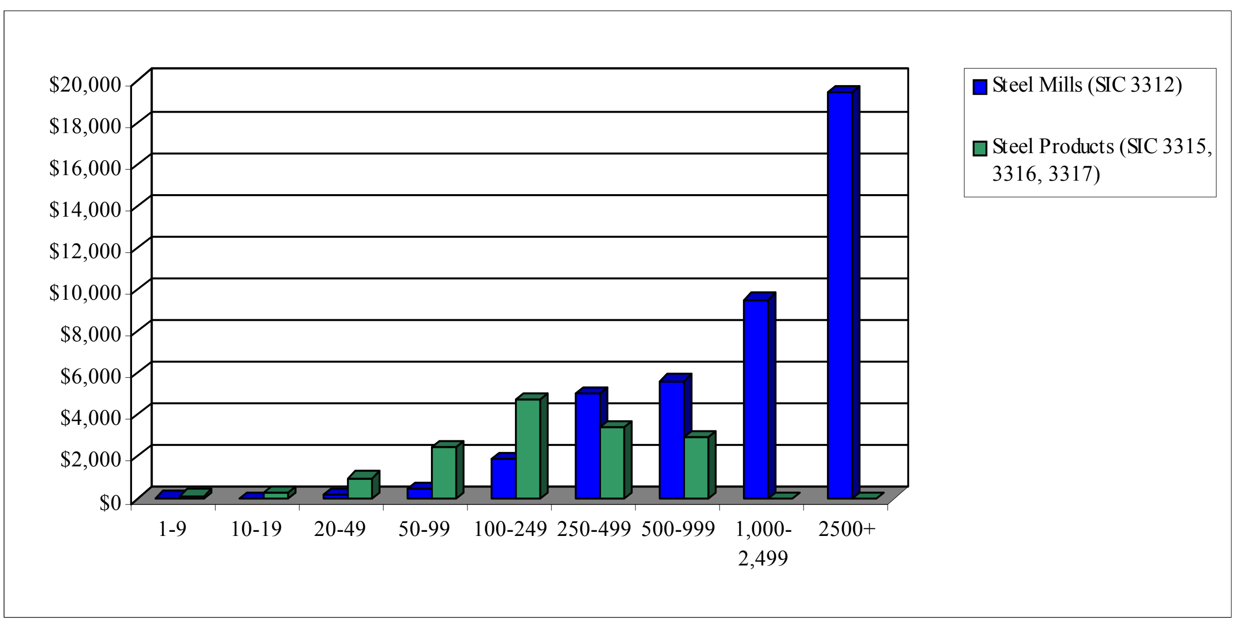
The Steel Products segment is characterized by smaller facilities than steel making, with only 26 percent of facilities in the segment employing 100 or more employees in 1992. While the majority of facilities in the Steel Products segment had fewer than 100 employees, most of the output from this segment was produced at the largest facilities. Figure B2D-6 shows that Steel Products facilities with more than 100 employees accounted for approximately 74 percent of the industry's 1992 value of shipments.

Figure B2D-6: Number of Facilities and Value of Shipments in 1992[a] by Employment Size Category for the Profiled Steel Industry Segments

Number of Facilities



Value of Shipments (in millions)



[a] The *1992 Census of Manufactures* is the most recent data available by SIC code and facility employment size.

Source: U.S. DOC, 1987, 1992, and 1997.

B2D-3.3 Firm Size

For both Steel Mills and Steel Products, the Small Business Administration defines a small firm as having 1,000 or fewer employees. The size categories reported in the Statistics of U.S. Businesses (SUSB) do not correspond with the SBA size classifications, therefore preventing precise use of the SBA size threshold in conjunction with SUSB data. Table B2D-8 below shows the distribution of firms, facilities, and receipts by the employment size of the parent firm. The SUSB data presented in Table B2D-8 show that in 2001, 1,172 of 1,254 firms in the Steel Mills segment had less than 500 employees. Therefore, at least 93 percent of firms in this segment were classified as small. These small firms owned 1,179 facilities, or 87 percent of all facilities in the segment.

Of the 811firms with facilities that manufacture Steel Products, 706, or 87 percent, employ fewer than 500 employees, and are therefore considered small businesses. Small firms own 74 percent of facilities in the industry.

Table B2D-8: Number of Firms, Facilities, and Estimated Receipts in the Profiled Steel Industry Segments by Employment Size Category, 2001

Employment Size Category	Steel Mills		Steel Products	
	Number of Firms	Number of Facilities	Number of Firms	Number of Facilities
0-19	959	959	438	438
20-99	154	154	162	175
100-499	58	66	106	149
500+	82	173	105	266
Total	1,254	1,352	811	*1,028*

Source: U.S. SBA, 2001.

B2D-3.4 Concentration Ratios

Concentration is the degree to which industry output is concentrated in a few large firms. Concentration is closely related to entry barriers with more concentrated industries generally having higher barriers.

The four-firm ***concentration ratio*** (CR4) and the ***Herfindahl-Hirschman Index*** (HHI) are common measures of industry concentration. The CR4 indicates the market share of the four largest firms. For example, a CR4 of 72 percent means that the four largest firms in the industry account for 72 percent of the industry's total value of shipments. The higher the concentration ratio, the less competition there is in the industry, other things being equal[6]. An industry with a CR4 of more than 50 percent is generally considered concentrated. The HHI indicates concentration based on the largest 50 firms in the industry. It is equal to the sum of the squares of the market shares for the largest 50 firms in the industry. For example, if an industry consists of only three firms with market shares of 60, 30, and 10 percent, respectively, the HHI of this industry would be equal to 4,600 ($60^2 + 30^2 + 10^2$). The higher the index, the fewer the number of firms supplying the industry and the more concentrated the industry. Based on the U.S. Department of Justice's guidelines for evaluating mergers, markets in which the HHI is under 1000 are considered unconcentrated, markets in which the HHI is between 1000 and 1800 are considered to be moderately concentrated, and those in which the HHI is in excess of 1800 are considered to be concentrated.

[6] Note that the measured concentration ratio and the HHF are very sensitive to how the industry is defined. An industry with a high concentration in domestic production may nonetheless be subject to significant competitive pressures if it competes with foreign producers or if it competes with products produced by other industries (e.g., plastics vs. aluminum in beverage containers). Concentration ratios based on share of production are therefore only one indicator of the extent of competition in an industry.

Table B2D-9 shows that Steel Mills have an HHI of 511 and that Steel Products, comprised of SIC 3315, 3316, and 3317, have HHIs of 201, 604, and 194, respectively. The Steel Mills and Steel Products segments are considered competitive, based on standard measures of concentration. The CR4 and the HHI for the relevant SIC codes are below the benchmarks of 50 percent and 1,000, respectively. Moreover, the table shows that each of the industry segments became more competitive between 1987 and 1992. The relatively low concentration values suggest that this factor would not contribute to the industry's ability to pass through compliance costs as price increases to customers.

Table B2D-9: Selected Ratios for the Profiled Steel Industry Segments

SIC Code	Year	Total Number of Firms	Concentration Ratios				
			4 Firm (CR4)	8 Firm (CR8)	20 Firm (CR20)	50 Firm (CR50)	Herfindahl-Hirschman Index
Steel Mills							
3312	1987	271	44%	63%	81%	94%	607
	1992	135	37%	58%	81%	96%	551
Steel Products							
3315	1987	274	21%	34%	54%	78%	212
	1992	271	19%	32%	54%	80%	201
3316	1987	156	45%	62%	82%	95%	654
	1992	158	43%	60%	81%	96%	604
3317	1987	155	23%	34%	58%	85%	242
	1992	166	19%	31%	53%	80%	194

[a] The *1992 Census of Manufactures* is the most recent concentration ratio data available by SIC code.

Source: *U.S. DOC, 1987, 1992, 1997.*

B2D-3.5 Foreign Trade

This profile uses two measures of foreign competition: ***export dependence*** and ***import penetration***.

Import penetration measures the extent to which domestic firms are exposed to foreign competition in domestic markets. Import penetration is calculated as total imports divided by total value of domestic consumption in that industry: where domestic consumption equals domestic production plus imports minus exports. Theory suggests that higher import penetration levels will reduce market power and pricing discretion because foreign competition limits domestic firms' ability to exercise such power. Firms belonging to segments in which imports account for a relatively large share of domestic sales would therefore be at a relative disadvantage in their ability to pass-through costs because foreign producers would not incur costs as a result of the Phase III regulation. The estimated import penetration ratio for the entire U.S. manufacturing sector (NAICS 31-33) for 2001 is 22 percent. For characterizing the ability of industries to withstand compliance cost burdens, EPA judges that industries with import ratios close to or above 22 percent would more likely face stiff competition from foreign firms and thus be less likely to succeed in passing compliance costs through to customers.

Export dependence, calculated as exports divided by value of shipments, measures the share of a segment's sales that is presumed subject to strong foreign competition in export markets. The Phase III regulation would not increase the production costs of foreign producers with whom domestic firms must compete in export markets. As a result, firms in industries that rely to a greater extent on export sales would have less latitude in increasing prices to recover cost increases resulting from regulation-induced increases in production costs. The estimated export dependence ratio for the entire U.S. manufacturing sector for 2001 is 15 percent. For characterizing the ability of industries to withstand compliance cost burdens, EPA judges that industries with export ratios close to or above 15 percent are at a relatively greater disadvantage in potentially recovering compliance costs through price increases since export sales are presumed subject to substantial competition from foreign producers.

The global market for steel continues to be extremely competitive. From 1945 until 1960, the U.S. steel industry enjoyed a period of tremendous prosperity and was a net exporter until 1959. However, by the early 1960s, foreign steel industries had thoroughly recovered from World War II and had begun construction of new plants that were more advanced and efficient than the U.S. integrated steel mills. Foreign producers also enjoyed lower labor costs, allowing them to take substantial market share from U.S. producers. This increased competition from foreign producers, combined with decreased consumption in some key end use markets, served as a catalyst for the restructuring and downsizing of the U.S. steel industry. The industry emerged from this restructuring considerably smaller, more technologically advanced and internationally competitive (S&P, 2001).

Table B2D-10 presents trade statistics for the profiled steel industry segments from 1990 to 2001. The table shows that while the trend in export dependence has been relatively stable, import penetration has increased from the early 1990s until 1998 and has since dropped. The drop after 1998 results from the trade protection measures mentioned above. Historically, the U.S. steel industry has exported a relatively small share of shipments compared to the steel industries of other developed nations (McGraw-Hill, 2000). U.S. exports rose in 1995 to the highest level since 1941, and remained relatively high through 2001. Imports penetration rose to 21 percent in 1998, after hovering around 15 percent in the early 1990s. This increase in imports reflected excess steel capacity worldwide and the competitiveness of foreign steel producers, as described previously. Canada received the largest amount of U.S. exported steel in 2003, followed by Mexico. Imports of steel mill products increased 8.4 percent from 2001 to 2002. Brazil, Canada, the EU, Japan, the Republic of Korea, Mexico, Russia, and Turkey were major sources of steel mill product imports (USGS, 2002).

The steel industry's import penetration ratio was 19 percent in 2001, implying that the industry currently faces moderate competition from foreign firms in setting prices for U.S. sales. However, as noted above, the removal of temporary import restrictions will leave the industry more exposed to competition from foreign producers. The steel industry's export dependence ratio in 2001 was eight percent, therefore the industry will not likely be affected by competitive pressures from abroad in export sales. This finding implies that the steel industry is not characterized by competitive pressures from foreign firms/markets and thus market power and cost pass through potential are not diminished by export penetration. However, it is questionable that firms in an industry will have a comparatively high cost pass-through potential simply because firms in that industry are not active in export markets. From the standpoint of firms gaining market power, EPA believes that the finding of low export dependence diminishes the importance of export competition as indicator of market power. Thus, other indicators must be relied upon to gauge the amount of market power firms in the steel industry are expected to hold. On balance, the U.S. steel industry is subject to significant international competitive pressure, largely manifesting though the penetration of foreign product into domestic markets. Although the U.S. industry's competitiveness against foreign producers improved in recent years, the industry remains substantially vulnerable to foreign competition, indicating a low likelihood that steel industry producers subject to the 316(b) regulation would be able to pass a material share of compliance costs through to customers.

Table B2D-10: Import Penetration and Export Dependence: Steel Mill Products

Year	Value of Imports (millions, $2003)	Value of Exports (millions, $2003)	Value of Shipments (millions, $2003)	Implied Domestic Consumption[a]	Import Penetration[b]	Export Dependence
B2989	12,440	3,864	84,803	93,379	13.3%	4.6%
1990	11,158	3,701	78,913	86,370	12.9%	4.7%
1991	10,204	4,729	69,041	74,516	13.7%	6.9%
1992	10,169	3,815	69,936	76,290	13.3%	5.5%
1993	10,884	3,496	73,280	80,668	13.5%	4.8%
1994	15,419	3,675	80,479	92,223	16.7%	4.6%
1995	14,529	5,506	84,557	93,580	15.5%	6.5%
1996	15,338	4,812	82,446	92,972	16.5%	5.8%
1997	16,224	5,603	83,830	94,451	17.2%	6.7%
1997[de]	16,436	5,754	83,830	94,512	17.4%	6.9%
1998[de]	19,683	5,416	81,744	96,011	20.5%	6.6%
1999[de]	15,241	4,946	74,877	85,172	17.9%	6.6%
2000[de]	17,415	5,544	73,771	85,642	20.3%	7.5%
2001[de]	13,240	5,181	61,996	70,055	18.9%	8.4%
Total Percent Change 1989-2001	*18.7%*	*40.0%*	*-21.4%*	*-18.9%*		
Average Annual Growth Rate	*1.4%*	*2.8%*	*-2.0%*	*-1.7%*		

[a] Calculated by EPA as shipments + imports - exports.
[b] Calculated by EPA as imports divided by implied domestic consumption.
[c] Calculated by EPA as exports divided by shipments.
[d] Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.
[e] As Census Trade data are not available before 1997, export and import values are taken from the International Trade Administration for years 1989-1997.

Source: ASM 1997-2001; ITA 1989-1997

B2D-4 FINANCIAL CONDITION AND PERFORMANCE

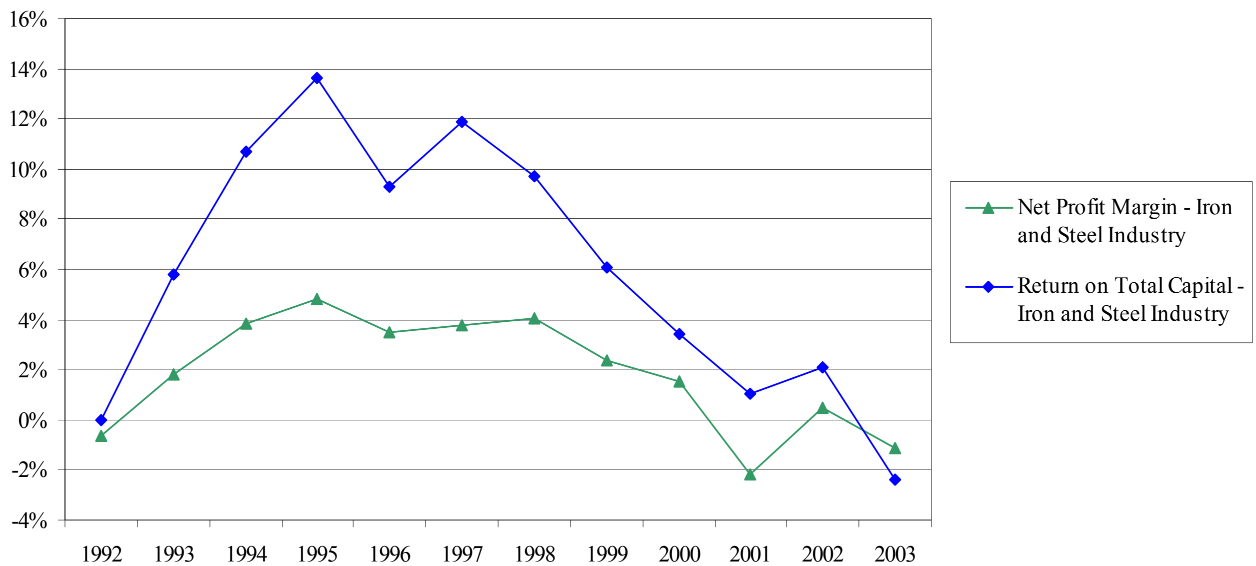
The financial performance and condition of the steel industry are important determinants of its ability to withstand the costs of regulatory compliance without material adverse economic/financial impact. To provide insight into the industry's financial performance and condition, EPA reviewed two key measures of financial performance over the 12-year period, 1992-2003: net profit margin and return on total capital. EPA calculated these measures as a revenue-weighted index of measure values for public reporting firms in the respective industries, using data from the Value Line Investment Survey. Financial performance in the most recent financial reporting period (2003) is obviously not a perfect indicator of conditions at the time of regulatory compliance. However, examining the trend, and deviation from the trend, through the most recent reporting period gives insight into where the industry *may be*, in terms of financial performance and condition, at the time of compliance. In addition, the volatility of performance against the trend, in itself, provides a measure of the *potential* risk faced by the industry in a future period in which compliance requirements are faced: all else equal, the more volatile the historical performance, the more likely the industry *may* be in a period of relatively weak financial conditions at the time of compliance.

Net profit margin is calculated as after-tax income before nonrecurring gains and losses as a percentage of sales or revenue, and measures profitability, as reflected in the conventional accounting concept of net income. Over time, the firms in an industry, and the industry collectively, must generate a sufficient positive profit margin if the industry is to remain economically viable and attract capital. Year-to-year fluctuations in profit margin stem from a several factors, including: variations in aggregate economic conditions (including international and U.S. conditions), variations in industry-specific market conditions (e.g., short-term capacity expansion resulting in overcapacity), or changes in the pricing and availability of inputs to the industry's production processes (e.g., the cost of energy to the steel production process). The extent to which these fluctuations affect an industry's profitability, in turn, depends heavily on the fixed vs. variable cost structure of the industry's operations. In a capital intensive industry such as the steel industry, the relatively high fixed capital costs as well as other fixed overhead outlays, can cause even small fluctuations in output or prices to have a large positive or negative affect on profit margin.

Return on total capital is calculated as annual net profit, plus one-half of annual long-term interest, divided by the total of shareholders' equity and long-term debt (total capital). This concept measures the total productivity of the capital deployed by a firm or industry, regardless of the financial source of the capital (i.e., equity, debt, or liability element). As such, the return on total capital provides insight into the profitability of a business' assets independent of financial structure and is thus a "purer" indicator of asset profitability than return on equity. In the same way as described for *net profit margin*, the firms in an industry, and the industry collectively, must generate over time a sufficient return on capital if the industry is to remain economically viable and attract capital. The factors causing short-term variation in *net profit margin* will also be the primary sources of short-term variation in *return on total capital*.

Figure B2D-7 presents trends in net profit margins and return on total capital for the steel industry between 1992 and 2003. The graph shows considerable volatility in the trend over this period. After registering improvement in financial performance in the first half of the 1990s, steel industry financial performance declined markedly from 1997/1998 forward to 2003, due first to increasing imports and later to general economic weakness. Measures of financial performance increased in 2002 when the U.S. steel industry received temporary relief with tariffs ranging up to 30 percent on certain steel imports. In 2003, however, the integrated steel industry had poor operating results, as high raw material costs outweighed increased sales and higher volumes.

Figure B2D-7: Net Profit Margin and Return on Total Capital for the Iron and Steel Industry



Source: Value Line, 1992-2003.

B2D-5 FACILITIES OPERATING COOLING WATER INTAKE STRUCTURES

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. In 1982, the Primary Metals industries as a whole (including Nonferrous and Steel producers) withdrew 1,312 billion gallons of cooling water, accounting for approximately 1.7 percent of total industrial cooling water intake in the United States[7]. The industry ranked 3rd in industrial cooling water use, behind the electric power generation industry, and the chemical industry (1982 Census of Manufactures).

This section provides information for facilities in the profiled steel segments potentially subject to the proposed regulation. Existing facilities that meet all of the following conditions are potentially subject to the proposed regulation:[8]

- 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;
- Have an National Pollutant Discharge Elimination System (NPDES) permit or are required to obtain one; and
- Have a design intake flow of greater than 2 million gallons per day (MGD).

The proposed regulation 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 section focuses on the 66

[7] Data on cooling water use are from the *1982 Census of Manufactures*. 1982 was the last year in which the Census of Manufactures reported cooling water use.

[8] The proposed Phase III regulation also applies to existing electric generating facilities as well as certain facilities in the oil and gas extraction industry and the seafood processing industry. See Chapters B4 and B5 and Part C of this document for more information on these industries.

facilities nation-wide in the profiled steel segments identified in EPA's 2000 Section 316(b) Industry Survey as being potentially subject to this proposed regulation[9]. Information collected in the Detailed Industry Questionnaire found that an estimated 46 out of 161 Steel Mills (29 percent) and 21 out of 309 Steel Product manufacturers (7 percent) meet the characteristics of a potential Phase III facility.

B2D-5.1 Waterbody and Cooling System Type

Minimills use electric-arc-furnace (EAF) to make steel from ferrous scrap. The electric-arc-furnace is extensively cooled by water and recycled through cooling towers (U.S. EPA, 1995). This is important to note since most new steel facilities are minimills.

Table B2D-11 shows the distribution of potential Phase III facilities in the profiled steel segments by type of water body and cooling system. The table shows that most of the potential Phase III facilities employ a combination of a once-through and recirculating system (23, or 35%) or a once through system (22, or 33%). The largest proportion of existing facilities draw water from a freshwater stream or river (52, or 79%).

Table B2D-11: Number of Potential Phase III Facilities in the Profiled Steel Industry Segments by Water Body Type and Cooling System Type

Water Body Type	Cooling Systems								Total
	Recirculating		Combination		Once-Through		Other		
	Number	% of Total	Number	% of Total	Number	% of Total	Number	% of Total	
Steel Mills									
Freshwater Stream/ River	5	16%	9	28%	11	34%	8	25%	32
Great Lake	0	0%	10	77%	3	23%	0	0%	13
Total†	***5***	***11%***	***19***	***41%***	***14***	***30%***	***8***	***17%***	***46***
Steel Products									
Freshwater Stream/ River	10	50%	3	15%	7	35%	0	0%	20
Lake/ Reservoir	0	0%	0	0%	1	100%	0	0%	1
Total†	***10***	***48%***	***3***	***14%***	***8***	***38%***	***0***	***0%***	***21***
Total for Profiled Steel Industry									
Freshwater Stream/ River	15	29%	12	23%	18	35%	8	15%	52
Great Lake	0	0%	10	77%	3	23%	0	0%	13
Lake/ Reservoir	0	0%	0	0%	1	100%	0	0%	1
Total[a]	***15***	***23%***	***23***	***35%***	***22***	***33%***	***8***	***12%***	***66***

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

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

[9] EPA applied sample weights to the sampled 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).

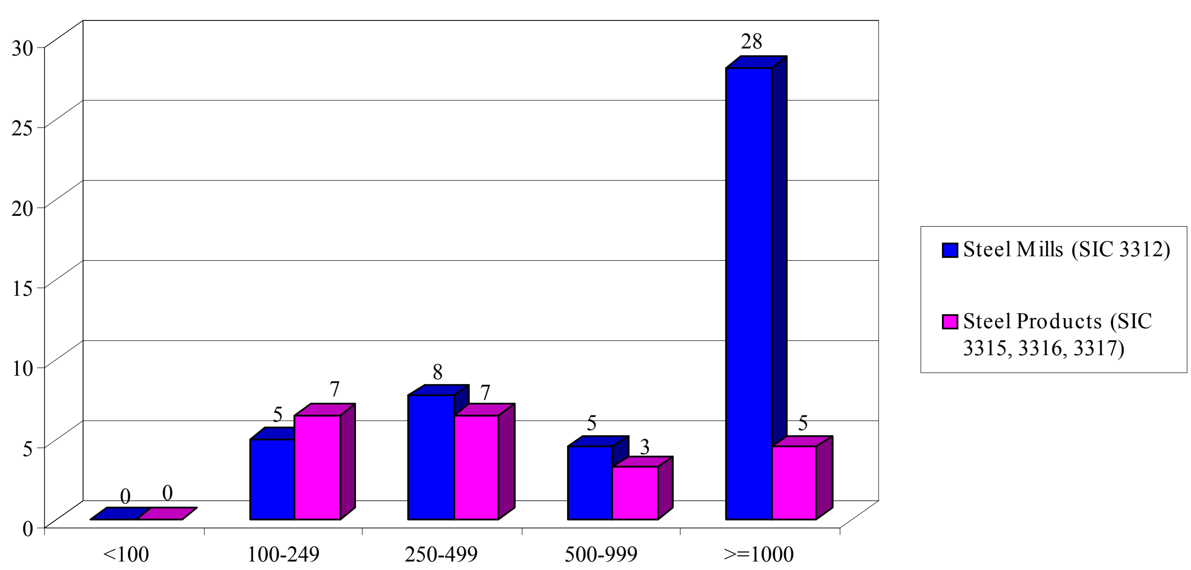
B2D-5.2 Facility Size

Section 316(b) sample Steel Mills and Steel Products facilities are larger than facilities in their industries as a whole, as reported in the Census and discussed previously:

- Sixty-four percent of all facilities in the steel segment had fewer than 100 employees in 1992; none of the potential Phase III facilities in that segment fall into that employment category.

Figure B2D-8 shows the number of potential Phase III facilities by employment size category.

Figure B2D-8: Number of Potential Phase III Facilities in the Profiled Steel Industry Segments by Employment Size



Source: U.S. EPA, 2000.

B2D-5.3 Firm Size

EPA used the Small Business Administration (SBA) small entity size standards to determine the number of existing Section 316(b) profiled steel industry facilities owned by small firms. Firms in the Steel Mills and Steel Products segments are defined as small if they have 1000 or fewer employees. Table B2D-12 shows that 7 of the 46 Section 316(b) Steel Mills, or 15 percent, are owned by small firms, while 6 (or 30 percent) of the Section 316(b) Steel Product facilities are owned by small firms. Overall, 53 facilities (80 percent) are owned by large firms, and 13 facilities (20 percent) are owned by small firms.

Table B2D-12: Number of Potential Phase III Facilities by Firm Size for the Profiled Steel Segments

SIC Code	Large		Small		Total
	Number	% of SIC	Number	% of SIC	
Steel Mills					
3312	39	85%	7	15%	46
Steel Products					
3315	3	50%	3	50%	7
3316	7	69%	3	31%	10
3317	5	100%	0	0%	5
Total[†]	**15**	**73%**	**6**	**30%**	**21**
Total for Profiled Steel Facilities					
Total[a]	**53**	**80%**	**13**	**20%**	**66**

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

Source: U.S. EPA, 2000; U.S. SBA, 2000; D&B, 2001.

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Chapter B2E: Aluminum (SIC 333/5)

EPA's *Detailed Industry Questionnaire*, hereafter referred to as the DQ, identified two 4-digit SIC codes in the nonferrous metals industries (SIC codes 333/335) with at least one existing facility that operates a CWIS, holds a NPDES permit, withdraws equal to or greater than two million gallons per day (MGD) from a water of the United States, and uses at least 25 percent of its intake flow for cooling purposes (facilities with these characteristics are hereafter referred to as facilities potentially subject to the Phase III regulation or "potential Phase III facilities").

For each of the two SIC codes, Table B2E-1 below provides a description of the industry segment, a list of products manufactured, the total number of detailed questionnaire respondents (weighted to represent national results), and the number and percent of potential Phase III facilities within the estimated national total of facilities in the respective industry SIC code groups.

CHAPTER CONTENTS

Table B2E-1: Potential Phase III facilities in the Aluminum Industries (SIC 333/335)

SIC	SIC Description	Important Products Manufactured	Number of Facilities[a]		
			Total	Potential Phase III facilities [b]	%
3334	Primary Production of Aluminum	Producing aluminum from alumina and in refining aluminum by any process	31	11	35.5%
3353	Aluminum Sheet, Plate, and Foil	Flat rolling aluminum and aluminum-base alloy basic shapes, such as rod and bar, pipe and tube, and tube blooms; producing tube by drawing	57	10	17.5%
Total			***88***	***21***	***24.0%***

[a] Number of weighted detailed questionnaire survey respondents.
[b] Individual numbers may not add up due to independent rounding.

Source: U.S. EPA, 2000; Executive Office of the President, 1987.

As reported in the table, EPA estimates that 21 out of 88 facilities (or 24 percent) in the Aluminum Industries (SIC 333/335) are potentially subject to this proposed regulation. EPA also estimated the percentage of total production that occurs at facilities potentially subject to the proposed regulation. Total value of shipments for the Aluminum Industries (SIC 333/335) from the 1998 Annual Survey of Manufacturers is $19.3 billion. Value of shipments, a measure of the dollar value of production, was selected for the basis of this estimate. Because value of shipments data were not collected using the DQ, these data were not available for the sample of Phase III manufacturing facilities potentially subject to the proposed regulation. Total revenue, as reported on the DQ, was used as a close approximation for value of shipments for these facilities. EPA estimated the total revenue of facilities in the aluminum industry subject to the proposed regulation is $12.1 billion. Therefore, EPA estimates that 63 percent of total domestic aluminum production occurs at facilities potentially subject to the proposed regulation.

Table B2E-2 provides the cross-walk between SIC codes and the new NAICS codes for the profiled aluminum SIC codes. The table shows that both of the profiled 4-digit SIC codes in the aluminum industry have a one-to-one relationship to NAICS codes.

Table B2E-2: Relationships between SIC and NAICS Codes for the Aluminum Industries (1997)

SIC Code	SIC Description	NAICS Code	NAICS Description	Number of Establishments	Value of Shipments ($1000)	Employment
3334	Primary aluminum	331312	Primary aluminum production	235	7,565,377	15,763
3353	Aluminum sheet, plate, and foil	331315	Aluminum sheet, plate, and foil manufacturing	70	13,755,566	25,111

Source: U.S. DOC, 1997.

B2E-1 SUMMARY INSIGHTS FROM THIS PROFILE

A key purpose of this profile is to provide insight into the ability of aluminum industry firms subject to the 316(b) regulation to absorb compliance costs without material adverse economic/financial effects. Two important factors in the industry's ability to withstand compliance costs are: (1) the extent to which the industry can shift compliance costs to its customers through price increases, and (2) the financial health of the industry and its general business outlook.

Likely Ability to Pass Compliance Costs Through to Customers
As reported in the following sections of this profile, the aluminum industry is moderately concentrated. This potentially supports firms in this industry passing through to customers a significant portion of their compliance-related costs. However, the domestic Primary Aluminum Production segment faces significant competition from imports into the U.S. market. Facilities in the Aluminum Sheet, Plate, and Foil segment have a notable reliance on foreign markets. The substantial competitive pressure from abroad weakens the potential of firms in this industry to pass through to customers a significant portion of their compliance-related costs. As discussed above, the proportion of total value of shipments in the industry potentially subject to the proposed regulation is 63 percent. The actual proportion of total value of shipments subject to regulation-induced compliance costs would be smaller since not all of the facilities would be subject to the national categorical requirements of the proposed regulation: that is, facilities below the proposed design intake flow (DIF) would be subject to permitting based on best professional judgement (BPJ) rather than based on national standards, and several facilities currently employ baseline technologies that meet the requirements of the proposed regulation. Given the likelihood that these percentages represent upper bound estimates, EPA believes that the theoretical threshold for justifying the use of industry-wide CPT rates in the impact analysis of existing Phase III aluminum facilities has not been met. For these reasons, in its analysis of regulatory impacts for the aluminum industry, EPA assumes that complying firms would be unable to pass compliance costs through to customers: i.e., complying facilities must absorb all compliance costs within their financial condition at the time of compliance (see following sections and Appendix 3 to *Chapter B3: Economic Impact Analysis for Manufacturers* for further information).

Financial Health and General Business Outlook
Over the past decade, the aluminum industry, like other U.S. manufacturing industries, has experienced a range of economic/financial conditions, including substantial challenges. In the early 1990s, the domestic aluminum

industry was adversely affected by reduced U.S. demand and the dissolution of the Soviet Union, resulting in large increases in Russian aluminum exports. Although domestic market conditions improved by mid-decade, weakness in Asian markets, along with growing Russian exports, dampened performance during the latter half of the 1990s. Demand for aluminum industry products declined again in 2000 through 2002, reflecting weakness in both the U.S. and world economies, and again resulted in oversupply and declining financial performance. More recently, as the U.S. economy began recovering from economic weakness, the domestic aluminum industry is showing signs of recovery with higher demand levels and improving financial performance over the course of 2003. Although the industry has weathered difficult periods over the past few years, the strengthening of the industry's financial condition and general business outlook suggest improved ability to withstand additional regulatory compliance costs without imposing significant financial impacts.

B2E-2 DOMESTIC PRODUCTION

Commercial production of aluminum using the electrolytic reduction process, known as the Hall-Heroult process, began in the late 1800s. The production of primary aluminum involves mining bauxite ore and refining it into alumina, one of the feedstocks for aluminum metal. Direct electric current is used to split the alumina into molten aluminum metal and carbon dioxide. The molten aluminum metal is then collected and cast into ingots. Technological improvements over the years have improved the efficiency of aluminum smelting, with a particular emphasis on reducing energy requirements. Currently, no commercially viable alternative exists to the electrometallurgical process (Aluminum Association, 2001).

In 2003, aluminum recovered from purchased scrap was about 2.8 million tons, of which about 60% came from new (manufacturing) scrap and 40% from old scrap (discarded aluminum products). Aluminum recovered from old scrap was equivalent to about 17% of apparent consumption (USGS, 2004a). Recycling consists of melting used beverage cans and scrap generated from operations. Recycling saves approximately 95 percent of the energy costs involved in primary smelting from bauxite (S&P, 2001). In contrast to the steel industry, aluminum minimills have had limited impact on the profitability of traditional integrated aluminum producers. Aluminum minimills are not able to produce can sheet of the same quality as that produced by integrated facilities. As a result, they are able to compete only in production of commodity sheet products for the building and distributor markets, which are considered mature markets. According to Standard & Poor's (2001), construction of new minimill capacity is unlikely given the potential that added capacity would drive down prices in the face of slow growth in the markets for minimill products. No secondary smelters (included, along with secondary smelting of other metals, in SIC code 3341) were reported in EPA's *Detailed Industry Questionnaire*. These facilities are therefore not addressed in this profile.

Facilities in SIC code 3353 produce semifabricated products from primary or secondary aluminum. Examples of semifabricated aluminum products include (Aluminum Association, undated):

- sheet (cans, construction materials, and automotive parts);
- plate (aircraft and spacecraft fuel tanks);
- foil (household aluminum foil, building insulation, and automotive parts);
- rod, bar, and wire (electrical transmission lines); and
- extrusions (storm windows, bridge structures, and automotive parts).

U.S. aluminum companies are generally vertically integrated. The major aluminum companies own large bauxite reserves, mine bauxite ore and refine it into alumina, produce aluminum ingot, and operate the rolling mills and finishing plants used to produce semifabricated aluminum products (S&P, 2001).

As noted, the production of primary aluminum is an electrometallurgical process, which is extremely energy intensive. Electricity accounts for approximately 30 percent of total production costs for primary aluminum smelting. The aluminum industry is therefore a major industrial user of electricity, spending more than $2 billion annually. The industry has pursued opportunities to reduce its use of electricity as a means of lowering costs. In the last 50 years, the average amount of electricity needed to make a pound of aluminum has declined from 12 kilowatt hours to approximately 7 kilowatt hours. (Aluminum Association, undated).

B2E-2.1 Output

The largest single source of demand for aluminum is the transportation segment, primarily the manufacture of motor vehicles. Demand for lighter, more fuel efficient vehicles has increased demand for aluminum in auto manufacturing, at the expense of steel (S&P, 2001). Until 1996, containers were the largest U.S. market for aluminum. Production of beverage cans is a major use of aluminum sheet, and aluminum has entirely replaced steel in the beverage can market. Other major uses of aluminum include construction (including aluminum siding, windows, and gutters) and consumer durables (USGS, 2001a).

Demand for aluminum reflects the overall state of the domestic and world economies, as well as long-term trends in materials use in major end-use sectors. Because aluminum production involves large fixed investments and capacity adapts slowly to fluctuations in demand, the industry has experienced alternating periods of excess capacity and tight supplies. The early 1980s was a period of oversupply, high inventories, and excess capacity. By 1986, excess capacity was closed, inventories were low, and demand increased substantially. The early 1990s were affected by reduced U.S. demand and the dissolution of the Soviet Union, resulting in large increases in Russian exports of aluminum. By the mid-1990s, global production declined, demand rebounded, and aluminum prices rose. Subsequent increased production reflected an overall increase in the demand for aluminum with stronger domestic economic growth, driven by increased consumption by the transportation, container, and construction segments. The economic crises in Asian markets in the later 1990s, along with growing Russian exports, again resulted in a period of oversupply, although U.S. demand for aluminum remained strong. Demand declined again in 2000 through 2002 due to slower growth in both the U.S. and the world economy, resulting in oversupply. The surplus was mitigated somewhat as demand in the automotive and housing markets remained relatively high through mid-2003. In addition, the California energy crisis in 2000 and 2001 reduced production from primary smelters located in the Pacific Northwest (Aluminum Association, 1999; USGS, 1999c; USGS, 1998e; USGS, 1994c; Value Line, 2001). Production in China increased during this period, and although increased Chinese consumption helped reduce the surplus slightly, the country switched from being a net importer to a net exporter. Additionally, interest rates are likely to increase which may decrease U.S. demand for aluminum from major industrial end markets (aerospace, automotive, home-construction, and commercial-construction). However, with the economy showing signs of recovery the aluminum industry saw higher demand levels in 2003. If the economy remains strong, demand is expected to continue at 2003 levels (Value Line, 2003; S&P 2004).

Table B2E-3 shows trends in output of aluminum by Primary Aluminum producers and recovery of aluminum from old and new scrap. Secondary production grew from 37 percent to over half of total domestic production over the period from 1990 to 2003. Of total secondary production in 2003, 1,170 thousand metric tons (MT) or 40 percent, is from old scrap (discarded aluminum products), as opposed to new scrap (from manufacturing). Primary production of aluminum recorded a net decrease over the 13-year period, but declined sharply in 2001 compared to 2000. As noted above, this decrease reflects reduced domestic and world demand for aluminum, and curtailed production at a number of Pacific Northwest mills caused by the California energy crisis (S&P 2001a; USGS, 2001a). Production remained fairly constant for the final three years of the period.

Table B2E-3: U.S. Quantities of Aluminum Produced

Year	Aluminum Ingot					
	Primary Production		Secondary Production (from old & new scrap)		Total Production	
	Thousand MT	% Change	Thousand MT	% Change	Thousand MT	% Change
1990	4,048	n/a	2,390	n/a	6,438	n/a
1991	4,121	1.8%	2,290	-4.2%	6,411	-0.4%
1992	4,042	-1.9%	2,760	20.5%	6,802	6.1%
1993	3,695	-8.6%	2,940	6.5%	6,635	-2.5%
1994	3,299	-10.7%	3,090	5.1%	6,389	-3.7%
1995	3,375	2.3%	3,190	3.2%	6,565	2.8%
1996	3,577	6.0%	3,310	3.8%	6,887	4.9%
1997	3,603	0.7%	3,550	7.3%	7,153	3.9%
1998	3,713	3.1%	3,440	-3.1%	7,153	0.0%
1999	3,779	1.8%	3,700	7.6%	7,479	4.6%
2000	3,688	-2.4%	3,450	-6.8%	7,138	-4.6%
2001	2,637	-28.5%	2,970	-13.9%	5,607	-21.4%
2002	2,707	2.7%	2,930	-1.3%	5,637	0.5%
2003	2,703	-0.1%	2,930	0.0%	5,633	-0.1%
Total percent change 1990-2003	*-33.2%*		*22.6%*		*-12.5%*	
Average annual growth rate	*-3.1%*		*1.6%*		*-1.0%*	

Source: USGS, 2001b-2003b; USGS 1996a-2004a; USGS 2002d

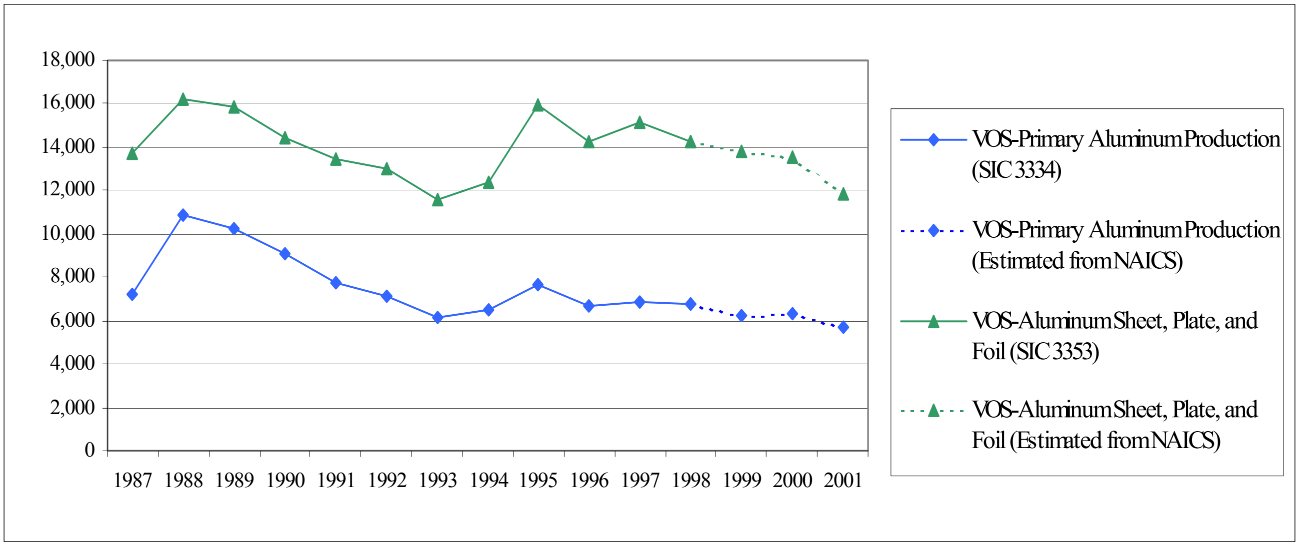
Value of shipments and value added are two common measures of manufacturing output[1]. They provide insight into the overall economic health and outlook for an industry. Value of shipments is the sum of the receipts a manufacturer earns from the sale of its outputs; it indicates the overall size of a market or the size of a firm in relation to its market or competitors. Value added measures the value of production activity in a particular industry. It is the difference between the value of shipments and the value of inputs used to make the products sold.

Figure B2E-1 reports constant dollar value of shipments and value added for the Primary Aluminum, and Aluminum Sheet, Plate, and Foil segments between 1987 and 2001.

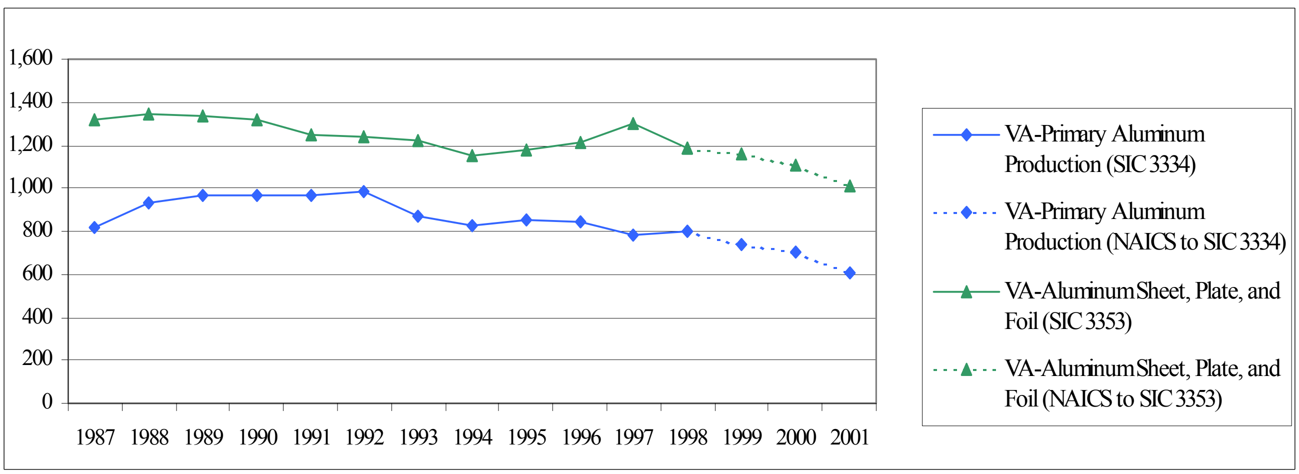
[1] Terms highlighted in bold and italic font are further explained in the glossary.

Figure B2E-1: Value of Shipments and Value Added for Profiled Aluminum Segments (millions,$2003)

Value of Shipments



Value Added



[a] Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications us`ing the 1997 Economic Census *Bridge Between NAICS and SIC.*

Source: U.S. DOC, 1988-1991, 1993-1996, and 1998-2001; U.S. DOC, 1987, 1992 and 1997.

The value of Primary Aluminum shipments shows generally the same pattern as the quantity data shown in Table B2E-3. Trends in production reflect trends in demand for aluminum, growth since 1990 in the percentage of domestic demand provided by imports, and increasing secondary production of aluminum, which substitutes in some but not all markets for primary production. Value added by aluminum production excludes the value of purchased materials and services (including electricity), and shows less fluctuation since 1990 than value of shipments.

Demand for semifinished aluminum products reflects demand from the transportation, container, and building industries. Real value of shipments of Aluminum Sheet, Plate, and Foil declined from the late 1980s through 1993, and then recovered by mid-decade, before turning down again in the late 1990s. Demand for semifinished products has been affected by strong growth in both the container and packaging segment and the auto segment (S&P, 2001).

Both industry segments show lower values for the constant dollar value of shipments and value added at the end of the 15-year analysis period than at the beginning of the period. These declining values reflect the overall maturity of the aluminum production industry and the increasing role of foreign production in meeting total U.S. demand.

B2E-2.2 Prices

The producer price index (PPI) measures price changes, by segment, from the perspective of the seller, and indicates the overall trend of product pricing, and thus supply-demand conditions, within a segment.

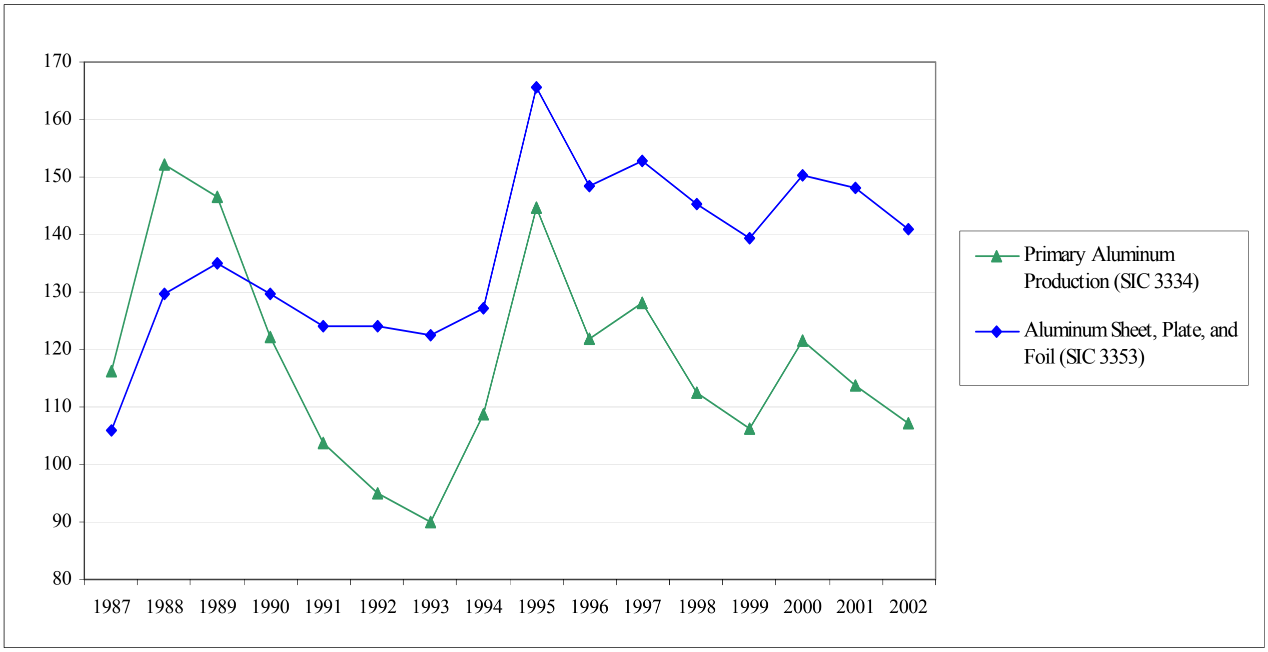
The price trends shown for Primary Aluminum in Figure B2E-2 reflect the fluctuations in world supply and demand discussed in the previous section. During the early 1980s, the aluminum industry experienced oversupply, high inventories, excess capacity, and weak demand, resulting in falling prices for aluminum. By 1986, much of the excess capacity had been permanently closed, inventories had been worked down, and worldwide demand for aluminum increased strongly. This resulted in price increases through 1988, as shown in Figure B2E.2.

In the early 1990s, the dissolution of the Soviet Union had a major impact on aluminum markets. Large quantities of Russian aluminum that formerly had been consumed internally, primarily in military applications, were sold in world markets to generate hard currency. At the same time, world demand for aluminum was decreasing. The result was increasing inventories and depressed aluminum prices.

The United States and five other primary aluminum producing nations signed an agreement in January 1994 to curtail global output, in response to the sharp decline in aluminum prices. At the time of the agreement, there was an estimated global overcapacity of 1.5 to 2.0 million metric tons per year (S&P, 2000).

By the mid-1990s, production cutbacks, increased demand, and declining inventories led to a sharp rebound of prices. Prices declined again though during the late 1990s, when the economic crises in Asian markets reduced the demand for aluminum (USGS, 2001b). During 2000, prices rebounded sharply despite the continuing trend of high Russian production and exports. However, economic recession caused prices to fall again through 2002. Prices began to recover during 2003 and are expected to continue on an upward trend as the economy recovers. (S&P, 2001-2004).

Figure B2E-2: Producer Price Indexes for Profiled Aluminum Segments



Source: BLS, 2002.

B2E-2.3 Number of Facilities and Firms

U.S. Geological Survey data indicate that the number of Primary Aluminum facilities and the number of firms that own them remained fairly constant over the period 1995 through 2001, as shown in Table B2E-4. The number of domestic companies and plants sharply declined in 2002 compared to 2001. In 2002, the 10 domestic producers had a total of 7 smelters that were either temporarily or permanently idled. The bulk of the idled capacity resulted from curtailed production at a number of Pacific Northwest mills caused by the California energy crisis. Most of the smelters outside of this region continued to operate at or near their engineered capacities (S&P 2001; USGS, 2001a; USGS, 2002c).

Table B2E-4: Primary Aluminum Production - Number of Companies and Plants

Year	Number of Companies	Number of Plants
1995	13	22
1996	13	22
1997	13	22
1998	13	23
1999	12	23
2000	12	23
2001	12	23
2002	7	16
2003	7	15

Source: USGS, 1996a-2004a.

Statistics of U.S. Businesses covers a larger number of facilities classified under SIC 3334 than do the USGS data, and also provide data on SIC 3353 (Aluminum Sheet, Plate, and Foil). These data, shown in Table B2E-5 and B2E-6, show more fluctuation in the number of establishments and the number of firms.

Table B2E-5 shows that the number of Primary Aluminum facilities decreased by 30 percent between 1991 and 1995, with the majority of this decrease, 27 percent, occurring between 1991 and 1993. The number of facilities in the Aluminum Sheet, Plate, and Foil segment showed a more consistent trend, increasing each year except in 1993. In 1998, the number of facilities decreased in both segments, but have continued to grow since then.

Table B2E-5: Number of Facilities for Profiled Aluminum Segments

Year	Primary Aluminum Production		Aluminum Sheet, Plate, and Foil	
	Number of Establishments	Percent Change	Number of Establishments	Percent Change
1989	56	n/a	61	n/a
1990	54	-3.6%	64	4.9%
1991	57	5.6%	73	14.1%
1992	52	-8.8%	73	0.0%
1993	44	-15.4%	63	-13.7%
1994	41	-6.8%	69	9.5%
1995	40	-2.4%	76	10.1%
1996	51	27.5%	81	6.6%
1997	34	-33.3%	91	12.3%
1998	28	-17.6%	83	-8.8%
1998[a]	28	-17.6%	79	-13.2%
1999[a]	29	3.6%	93	17.7%
2000[a]	32	10.3%	103	10.8%
2001[a]	38	18.8%	111	7.8%
Total Percent Change 1989-2001	*-32.1%*		*82.0%*	
Average Annual Growth Rate	*-3.2%*		*5.1%*	

[a] Before 1998, these data were compiled in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

Source: U.S. SBA, 1989-2001.

The trend in the number of firms over the period between 1989 and 2001 is similar to the trend in the number of facilities in both industry segments. Table B2E-6 on the following page presents SUSB information on the number of firms in each segment between 1989 and 2001.

Table B2E-6: Number of Firms for Profiled Aluminum Segments

Year	Primary Aluminum Production		Aluminum Sheet, Plate, and Foil	
	Number of Firms	**Percent Change**	**Number of Firms**	**Percent Change**
1990	38	n/a	43	n/a
1991	41	7.9%	53	23.3%
1992	36	-12.2%	53	0.0%
1993	33	-8.3%	45	-15.1%
1994	30	-9.1%	47	4.4%
1995	30	0.0%	51	8.5%
1996	40	33.3%	56	9.8%
1997	23	-42.5%	66	17.9%
1998	19	-17.4%	60	-9.1%
1998[a]	19	-17.4%	56	-15.2%
1999[a]	20	5.3%	66	17.9%
2000[a]	22	10.0%	73	10.6%
2001[a]	28	27.3%	82	12.3%
Total Percent Change 1990-2001	*-26.3%*		*90.7%*	
Average Annual Growth Rate	*-2.7%*		*6.0%*	

[a] Before 1998, these data were compiled in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

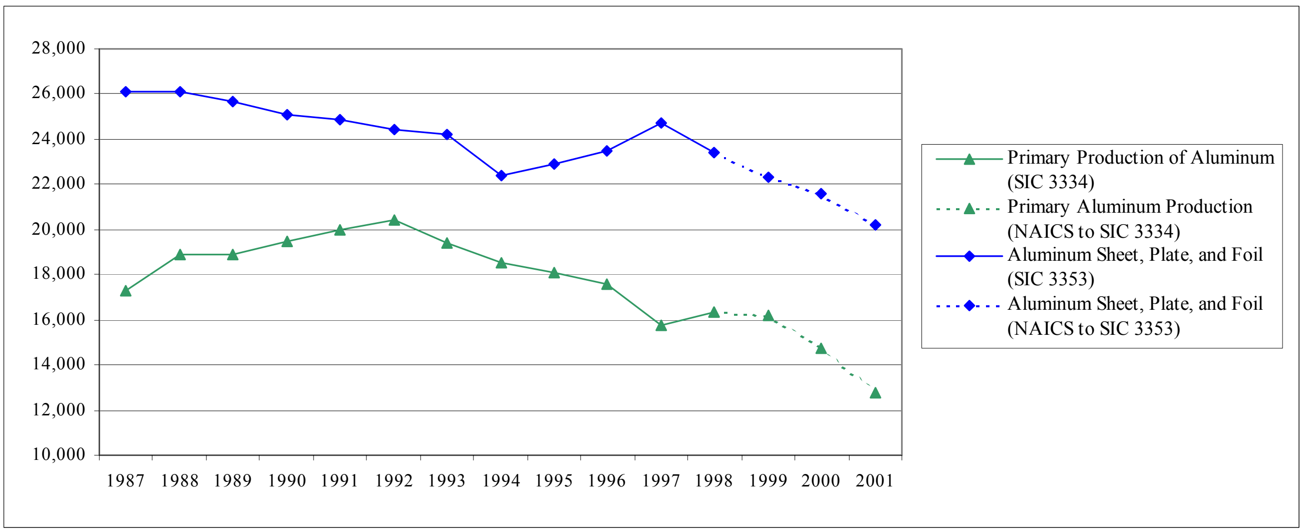
Source: U.S. SBA, 1989-2001.

B2E-2.4 Employment and Productivity

Figure B2E-3, below, provides information on employment from the Annual Survey of Manufactures for the Primary Aluminum and Aluminum Sheet, Plate, and Foil segments. Trends in Primary Aluminum facility employment reflect trends in both production and producers' efforts to improve labor productivity to compete with less labor-intensive minimills (McGraw-Hill, 2000). The figure shows that employment in the Primary Aluminum segment has declined steadily since 1992, even in years of increased production.

Employment in the Aluminum Sheet, Plate, and Foil segment declined from 1987 through 1994, but rose between 1995 and 1997, before declining again during 1997 to 2001. Employment in the Primary Aluminum Production segment increased during the 1987 to 1992 period, but fell persistently over the remainder of the 1990s decade and through 2001. For both industry segments, the low employment level in 2001 resulted from the idled capacity from curtailed production at a number of Pacific Northwest mills caused by the California energy crisis.

Figure B2E-3: Employment for Profiled Aluminum Segments



[a] Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC.*

Source: U.S. DOC, 1988-1991, 1993-1996, and 1998-2001; U.S. DOC, 1987, 1992, and 1997.

Table B2E-7 presents the change in value added per labor hour, a measure of labor productivity, for the Primary Aluminum Production and Aluminum Sheet, Plate, and Foil segments between 1987 and 2001. The trend in labor productivity in both segments showed volatility over this period, reflecting variations in capacity utilization. Value added per hour in the Primary Aluminum segment showed a 3.3 percent net increase over the entire period 1987 and 2001. Value added per hour in the Aluminum Sheet, Plate, and Foil segment saw a three percent decrease over the whole period between 1987 and 2001.

Table B2E-7: Productivity Trends for Profiled Aluminum Segments ($2003)

Year	Primary Production of Aluminum				Aluminum Sheet, Plate, and Foil			
	Value Added (millions)	Production Hours (millions)	Value Added/Hour		Value Added (millions)	Production Hours (millions)	Value Added/Hour	
			($/hour)	Percent Change			($/hour)	Percent Change
1987	821	28	30	n/a	1,317	40	33	n/a
1988	933	32	29	-2%	1,345	41	33	0%
1989	964	30	32	9%	1,336	41	33	0%
1990	971	32	30	-5%	1,322	40	33	2%
1991	971	32	30	0%	1,251	39	32	-4%
1992	986	32	31	1%	1,241	40	31	-2%
1993	870	29	30	-2%	1,224	39	32	2%
1994	827	27	31	2%	1,148	37	31	-1%
1995	855	28	30	-2%	1,178	38	31	-2%
1996	844	29	30	-2%	1,215	39	31	1%
1997	783	26	30	1%	1,302	41	32	1%
1998[a]	800	27	30	0%	1,187	39	31	-3%
1999[a]	742	26	29	-5%	1,158	37	32	3%
2000[a]	700	24	29	0%	1,110	35	32	1%
2001[a]	607	19	31	9%	1,011	32	32	-2%
Total Percent Change 1987-2001	*-26.1%*	*-32.1%*	*3.3%*		*-23.2%*	*-20.0%*	*-3.0%*	
Average Annual Growth Rate	*-2.1%*	*-2.7%*	*0.2%*		*-1.9%*	*-1.6%*	*-0.2%*	

[a] Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

Source: U.S. DOC, 1988-1991, 1993-1996, and 1998-2001; U.S. DOC, 1987, 1992, and 1997.

B2E-2.5 Capital Expenditures

Aluminum production is a highly capital-intensive process. Capital expenditures are needed to modernize, replace, and when market conditions warrant, expand capacity. Environmental requirements also require major capital expenditures.

Capital expenditures in the Primary Aluminum Production and Aluminum Sheet, Plate, and Foil segments between 1987 and 2001 are presented in Table B2E-8 below. The table shows that capital expenditures in the Primary Aluminum segment increased throughout the early 1990s, reaching a high in 1992 and again in 1998. In between these two periods of increased capital investment there was a significant decrease of 46 percent between 1992 and 1994. These decreases resulted from the production cutbacks and capacity reductions implemented in response to oversupply conditions prevalent in the market for aluminum.

Capital expenditures in the Aluminum Sheet, Plate, and Foil segment also fluctuated considerably between 1987 and 2001, with the highest values occurring in 1990, two years earlier than in the Primary Aluminum segment. Although producers of Aluminum Sheet, Plate, and Foil reduced capital expenditures by approximately 50 percent between 1988 and 1997, outlays began to increase in 2001.

Table B2E-8: Capital Expenditures for Profiled Aluminum Segments (millions, $2003)

Year	Primary Aluminum Production		Aluminum Sheet, Plate, and Foil	
	Capital Expenditures	Percent Change	Capital Expenditures	Percent Change
1987	250	n/a	634	n/a
1988	205	-18.2%	731	15.4%
1989	245	19.4%	742	1.5%
1990	243	-0.6%	882	18.9%
1991	260	6.8%	710	-19.6%
1992	263	1.2%	512	-27.9%
1993	200	-24.0%	289	-43.6%
1994	141	-29.2%	321	11.1%
1995	174	23.0%	435	35.5%
1996	233	34.0%	451	3.7%
1997	355	52.2%	367	-18.5%
1998[a]	432	21.8%	348	-5.3%
1999[a]	380	-12.2%	352	1.2%
2000[a]	371	-2.3%	367	4.1%
2001[a]	266	-28.4%	594	62.1%
Total Percent Change 1987-2001	*6.4%*		*-6.3%*	
Average Annual Growth Rate	*0.4%*		*-0.5%*	

[a] Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

Source: U.S. DOC, 1988-1991, 1993-1996, and 1998-2001; U.S. DOC, 1987, 1992, and 1997.

B2E-2.6 Capacity Utilization

Capacity utilization measures actual output as a percentage of total potential output given the available capacity. Capacity utilization reflects excess or insufficient capacity in an industry and is an indication of whether new investment is likely. Capacity utilization is also closely linked to financial performance for industries with substantial fixed costs, such as the aluminum industry. Like integrated steel mills, the aluminum manufacturing process requires a large capital base to transform raw material into finished product. Because of the resulting high fixed costs of production, earnings can be very sensitive to production levels, with high output levels relative to capacity needed for plants to remain profitable.

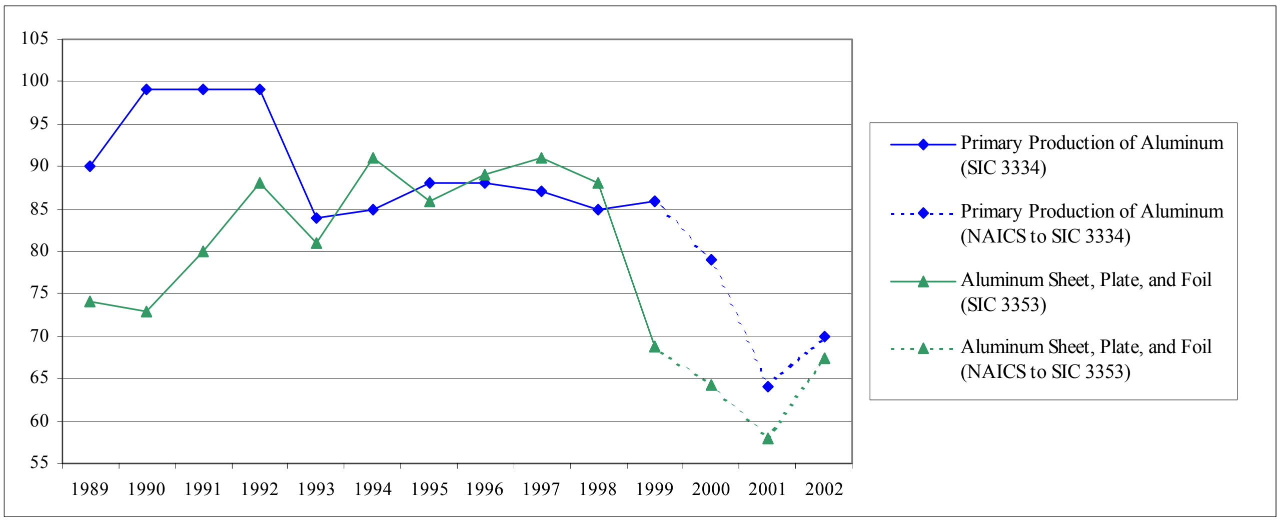
Figure B2E-4 shows capacity utilization from 1989 to 2002 for the Primary Aluminum Production and Aluminum Sheet, Plate, and Foil segments. The figure shows that for most of the 1990s, the Primary Aluminum segment was characterized by excess capacity. Although capacity utilization for this segment was in the high 90 percent range between 1990 and 1992, domestic utilization fell sharply in 1993 as large amounts of Russian aluminum entered the global market for the first time (McGraw-Hill, 1999). Capacity utilization remained at this lower level through 1999. In 2000 and 2001, capacity utilization fell again reflecting the general weakening of product demand during the Asian economic crisis and later, general economic weakness in the U.S. and world economies. Reflecting the economic recovery, product demand increased and capacity utilization rose during 2002.

A substantial amount of U.S. capacity remains idled, which could be brought on-line as demand improves. This "overhang" idle capacity is likely to limit construction of new capacity and to limit price increases for aluminum

(S&P, 2001). No new smelter capacity has been constructed in the United States since 1980 (McGraw-Hill, 1999). The ten domestic producers of primary aluminum had a total of 7 smelters that were either temporarily or permanently idled in 2002. By the end of 2002, about 1.5 million metric tons per year of domestic primary aluminum smelting capacity, equivalent to 35 percent of total capacity, was closed. Of this total, 270,000 metric tons per year of capacity was permanently closed and the remainder was classified as temporarily idled. The bulk of the idled capacity was due to curtailed production at a number of Pacific Northwest mills caused by the California energy crisis (USGS, 2002c).

Although also experiencing year-to-year fluctuation, capacity utilization in the Aluminum Sheet, Plate, and Foil segment grew overall between 1989 and 1998. This growth resulted largely from the continued strength of rolled aluminum products, which account for more than 50 percent of all shipments from the aluminum industry. Increased consumption by the transportation segment, the largest end-use segment for aluminum sheet, plate, and foil, is responsible for bringing idle capacity into production (McGraw-Hill 1999) However, falling demand in these segments after 1998 and through 2001, led to a marked fall-off in capacity utilization. Again, reflecting the economic recovery during 2002, capacity utilization rose substantially in this segment.

Figure B2E-4: Capacity Utilization Rates (Fourth Quarter) for Profiled Aluminum Segments



[a] Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

Source: U.S. DOC, 1989-2002.

B2E-3 STRUCTURE AND COMPETITIVENESS

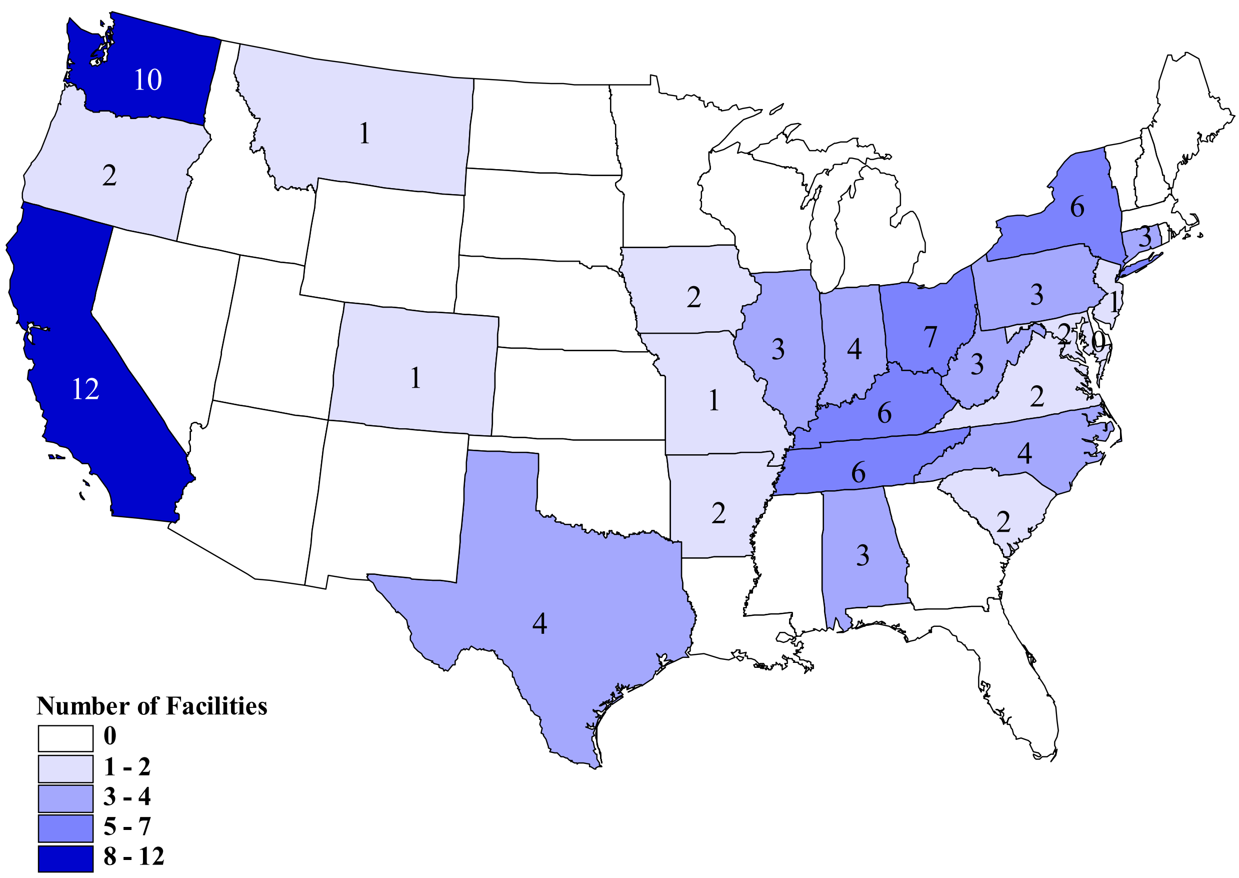
Aluminum production is a highly-concentrated industry. A number of large mergers among aluminum producers have increased the degree of concentration in the industry. For example, Alcoa (the largest aluminum producer) acquired Alumax (the third largest producer) in 1998 and Reynolds (the second largest producer) in May 2000. Alcan acquired Algroup in 2000 and Pechiney in 2004. Three companies now account for just over 50 percent of global aluminum output (S&P, 2004). Some sources speculate that, with increased consolidation resulting from mergers, aluminum producers might refrain from returning idle capacity to production as demand for aluminum grows, which could reduce the cyclical volatility in production and aluminum prices that has characterized the industry in the past (S&P, 2000).

B2E-3.1 Geographic Distribution

The cost and availability of electricity is a driving force behind decisions on the location of new or expanded smelter capacity. The Primary Aluminum producers are generally located in the Pacific Northwest (OR, MT, WA) and the Ohio River Valley (IL, IN, KY, MI, MO, OH, PA), where supplies of lower-priced hydroelectric and coal-based electricity are abundant. In 2002, the 11 smelters east of the Mississippi River accounted for 75 percent of production; whereas the remaining 11 smelters, which included the 9 Pacific Northwest smelters, accounted for only 25 percent (USGS, 2004a). Aluminum consumption was centered in the East Central United States (USGS, 2004a). The Aluminum Sheet, Plate, and Foil segment is located principally in California and the Appalachian Region (Alabama, Kentucky, Maryland, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia).

Figure B2E-5 shows the distribution of all facilities by State in both profiled aluminum segments (primary smelters and Aluminum Sheet, Plate, and Foil producers), based on the 1992 Census of Manufactures.[2]

Figure B2E-5: Number of Facilities by State for Aluminum Segments (SIC 3334 and 3353)



Source: U.S. DOC, 1987, 1992, and 1997.

[2] The *1992 Census of Manufactures* is the most recent data available by SIC code and State.

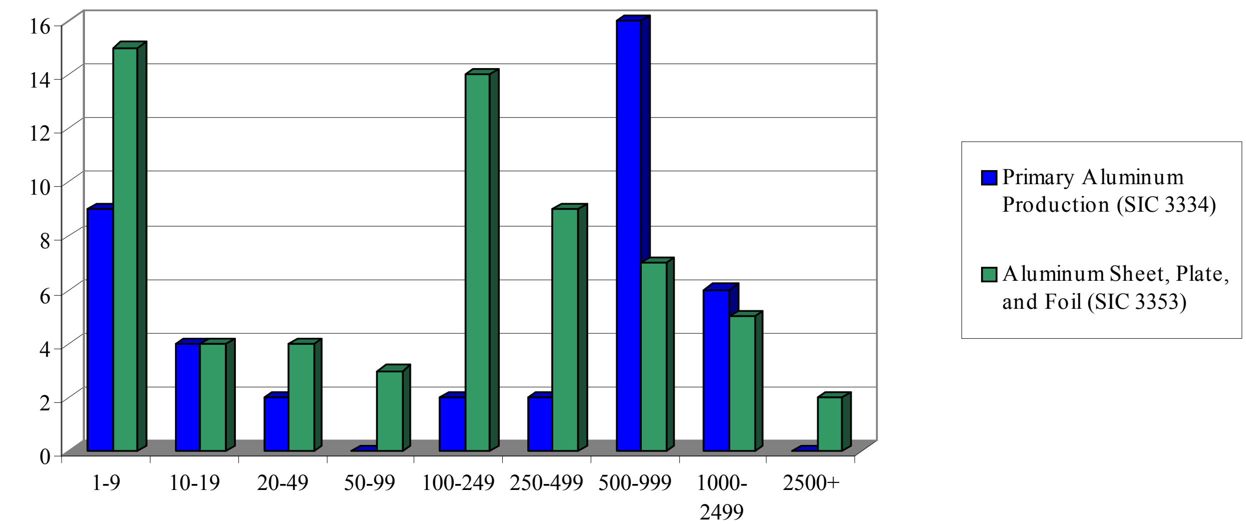
B2E-3.2 Facility Size

Facility size can be expressed by the number of employees and/or by the total value of shipments, with the most accurate depiction of size being a combination of both.

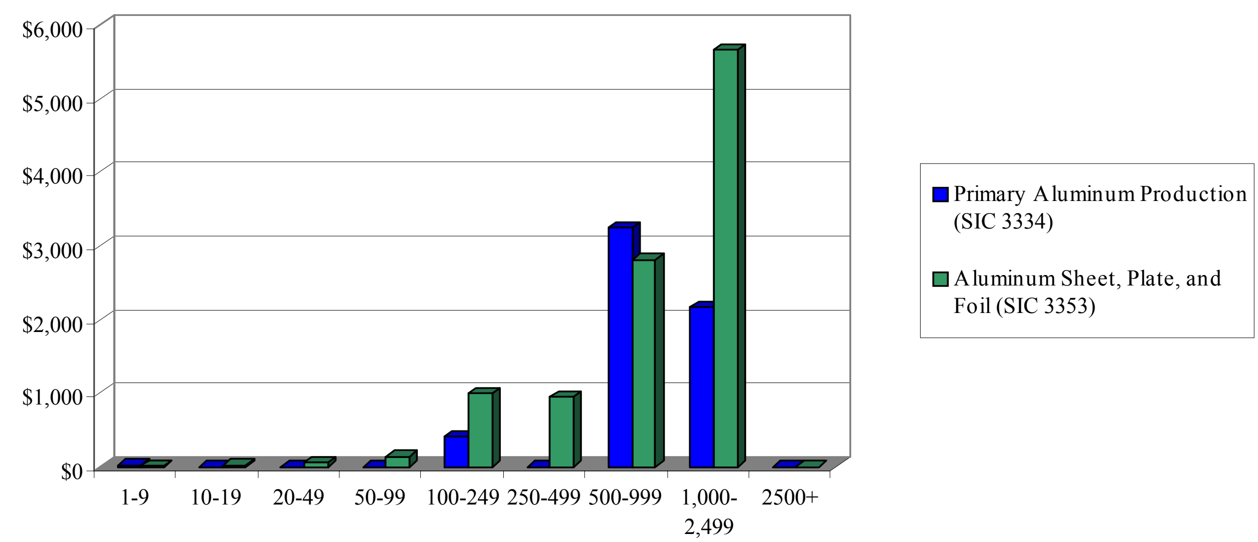
Economic Census data include numerous small facilities (less than 10 employees) for the profiled aluminum segments, as shown in Figure B2E-6. These facilities may not be production facilities. Value of shipments, however, are dominated by large establishments (greater than 500 employees) for both the Primary Aluminum and Aluminum Sheet, Plate, and Foil industry segments. Figure B2E-6 shows that 93 percent of the value of shipments for the Primary Aluminum segment is produced by establishments with more than 250 employees. Approximately 88 percent of the value of shipments for the Aluminum Sheet, Plate, and Foil industry is produced by establishments with more than 250 employees. Establishments in the Primary Aluminum Production and the Aluminum Sheet, Plate, and Foil segments with more than 1,000 employees are responsible for approximately 37 and 53 percent of all industry shipments, respectively.

Figure B2E-6: Number of Facilities and Value of Shipments in 1992[a] by Facility Employment Size Category for Profiled Aluminum Segments

Number of Facilities



Value of Shipments (in millions)



[a] The *1992 Census of Manufactures* is the most recent data available by SIC code and facility employment size.

Source: U.S. DOC, 1987, 1992, and 1997.

B2E-3.3 Firm Size

The Small Business Administration (SBA) defines a small firm for SIC codes 3334 and 3353 as a firm with 1,000 or fewer and 750 or fewer employees, respectively. The Statistics of U.S. Businesses (SUSB) provide employment data for firms with 500 or fewer employees and do not specify data for companies with 500-750 employees for SIC 3353 and 500-1000 for SIC 3334. Therefore, based on 2001 data for firms with up to 500 employees,

- 18 of the 28 firms in the Primary Aluminum Production segment had less than 500 employees. Therefore, at least 64 percent of this segment's firms are classified as small. These small firms owned 18 facilities, or 47 percent of all facilities in the segment.

- 67 of the 82 firms in the Aluminum Sheet, Plate and Foil segment had less than 500 employees. Therefore, at least 82 percent of this segment's firms are classified as small. These small firms owned 69 facilities, or 62 percent of all facilities in the segment.

Table B2E-9 below shows the distribution of firms and facilities in SIC 3334 and 3353 by the employment size of the parent firm.

Table B2E-9: Number of Firms and Facilities by Employment Size Category for the Profiled Aluminum Segments, 2001

Employment Size Category	Primary Aluminum Production		Aluminum Sheet, Plate, and Foil	
	Number of Firms	Number of Facilities	Number of Firms	Number of Facilities
0-19	13	13	42	43
20-99	4	4	16	16
100-499	1	1	9	10
500+	10	20	15	42
Total	*28*	*38*	*82*	*111*

Source: U.S. SBA, 2001.

B2E-3.4 Concentration Ratios

Concentration is the degree to which industry output is concentrated in a few large firms. Concentration is closely related to entry barriers with more concentrated industries generally having higher barriers.

The four-firm concentration ratio (CR4) and the Herfindahl-Hirschman Index (HHI) are common measures of industry concentration. The CR4 indicates the market share of the four largest firms. For example, a CR4 of 72 percent means that the four largest firms in the industry account for 72 percent of the industry's total value of shipments. The higher the concentration ratio, the less competition there is in the industry, other things being equal[3]. An industry with a CR4 of more than 50 percent is generally considered concentrated. The HHI indicates concentration based on the largest 50 firms in the industry. It is equal to the sum of the squares of the market shares for the largest 50 firms in the industry. For example, if an industry consists of only three firms with market shares of 60, 30, and 10 percent, respectively, the HHI of this industry would be equal to 4,600 ($60^2 + 30^2 + 10^2$). The higher the index, the fewer the number of firms supplying the industry and the more concentrated the industry. Based on the U.S. Department of Justice's guidelines for evaluating mergers, markets in which the HHI is under 1000 are considered unconcentrated, markets in which the HHI is between 1000 and 1800 are considered to be moderately concentrated, and those in which the HHI is in excess of 1800 are considered to be concentrated.

Table B2E-10 shows that Primary Aluminum has an HHI of 1231 and Aluminum Sheet, Plate and Foil has an HHI of 1447. The Primary Aluminum and Aluminum Sheet, Plate, and Foil segments, with HHI values of 1231

[3] Note that the measured concentration ratio and the HHF are very sensitive to how the industry is defined. An industry with a high concentration in domestic production may nonetheless be subject to significant competitive pressures if it competes with foreign producers or if it competes with products produced by other industries (e.g., plastics vs. aluminum in beverage containers). Concentration ratios based on share of domestic production are therefore only one indicator of the extent of competition in an industry.

and 1447, respectively, appear to be moderately concentrated. Thus, based on this factor, firms in the aluminum industry may enjoy moderate amounts of market power, which may enable them to pass-through costs at a more than negligible rate. However, an accurate assessment of the cost pass-through potential of firms in the Aluminum industry must be considered in conjunction with other measures of market power.

The four largest firms in Primary Aluminum Production accounted for 59 percent of total U.S. primary capacity in 1992. Consolidation in the industry since the early 1990s has increased concentration. With the merger of Alcoa, Inc. and Reynolds in May 2000, the single merged company accounted for 50 percent of domestic primary aluminum capacity, and the four largest U.S. producers control 72 percent of the domestic capacity (Alcoa Inc. for 50 percent, Century Aluminum Co. for almost 10 percent, and Noranda Aluminum Inc. and Ormet Primary Aluminum Corp. for 6 percent each) reported at the end of 2002 (USGS, 2002c).

Table B2E-10: Selected Ratios for the Profiled Aluminum Segments

SIC Code	Year	Total Number of Firms	Concentration Ratios				
			4 Firm (CR4)	8 Firm (CR8)	20 Firm (CR20)	50 Firm (CR50)	Herfindahl-Hirschman Index
3334	1987	34	74%	95%	99%	100%	1934
	1992	30	59%	82%	99%	100%	1456
	1997	13	59%	82%	100%	100%	1231
3353	1987	39	74%	91%	99%	100%	1719
	1992	45	68%	86%	99%	100%	1633
	1997	41	65%	85%	98%	100%	1447

Source: U.S. DOC, 1987, 1992, and 1997.

B2E-3.5 Foreign Trade

This profile uses two measures of foreign competition: export dependence and import penetration.

Import penetration measures the extent to which domestic firms are exposed to foreign competition in domestic markets. Import penetration is calculated as total imports divided by total value of domestic consumption in that industry: where domestic consumption equals domestic production plus imports minus exports. Theory suggests that higher import penetration levels will reduce market power and pricing discretion because foreign competition limits domestic firms' ability to exercise such power. Firms belonging to segments in which imports account for a relatively large share of domestic sales would therefore be at a relative disadvantage in their ability to pass-through costs because foreign producers would not incur costs as a result of the Phase III regulation. The estimated import penetration ratio for the entire U.S. manufacturing sector (NAICS 31-33) for 2001 is 22 percent. For characterizing the ability of industries to withstand compliance cost burdens, EPA judges that industries with import ratios close to or above 22 percent would more likely face stiff competition from foreign firms and thus be less likely to succeed in passing compliance costs through to customers.

Export dependence, calculated as exports divided by value of shipments, measures the share of a segment's sales that is presumed subject to strong foreign competition in export markets. The Phase III regulation would not increase the production costs of foreign producers with whom domestic firms must compete in export markets. As a result, firms in industries that rely to a greater extent on export sales would have less latitude in increasing prices to recover cost increases resulting from regulation-induced increases in production costs. The estimated export dependence ratio for the entire U.S. manufacturing sector for 2001 is 15 percent. For characterizing the ability of industries to withstand compliance cost burdens, EPA judges that industries with export ratios close to or above 15 percent are at a relatively greater disadvantage in potentially recovering compliance costs through price increases since export sales are presumed subject to substantial competition from foreign producers.

Table B2E-11 reports export dependence and import penetration for both the Primary Aluminum Production and the Aluminum Sheet, Plate, and Foil segments, since 1993. Imports of Primary Aluminum rose dramatically in 1994, primarily due to the large exports from Russian producers. Representatives of major aluminum producing countries met in late 1993 and 1994 to address the excess global supply of primary aluminum. Those discussions resulted in the Russian Federation's agreement to reduce production by 500,000 MTs per year, and plans for other producers to cut their production and to assist Russian producers to improve their environmental performance and stimulate the development of internal demand for the Russian production (USGS, 1994c). Nonetheless, imports have continued to represent a substantial and growing proportion of U.S. demand, reaching an estimated 44 percent in 2001 for Primary Aluminum Production. By 2002, Canada was the largest supplier of imports, supplying more than one-half of total imports. Russia continued to be the second largest supplier of aluminum materials to the U.S. (USGS, 2002c). The majority of U.S. exports (two-thirds) are shipped to Canada and Mexico.

As discussed previously, the import penetration ratio for the Primary Aluminum Production segment in 2001 was 44 percent, which is twice the U.S. manufacturing segment average of 22 percent. The export ratio for Primary Aluminum Production in 2001 was eight percent; therefore the segment will not likely be affected by competitive pressures from abroad in export sales. On balance, the U.S. Primary Aluminum Production segment is subject to significant international competitive pressure, largely manifesting though the penetration of foreign product into domestic markets. This finding indicates a low likelihood that Primary Aluminum producers subject to the 316(b) regulation would be able to pass a material share of compliance costs through to customers.

In 2001, the import penetration ratio for facilities in the Aluminum Sheet, Plate, and Foil segment was 11 percent, which is one-half of the U.S. manufacturing segment average of 22 percent. In 2001, the export dependence ratio for this segment was 15 percent, or approximately the average for U.S. manufacturers. This industry segment appears to face lower competition from foreign producers in domestic markets than the Primary Aluminum Production segment, but this segment competes more vigorously in foreign markets, where it is more exposed to foreign competition than the Primary Aluminum Production segment. On balance, this industry segment is likely to face moderate competitive pressure from foreign producers, whether in domestic or export markets, in attempting to recover regulation-induced increases in production costs through price increase.

Overall, the competitive pressure from foreign firms/markets may offset the finding, stated above, that the aluminum industry would appear to possess market power from being a moderately concentrated industry. As a result, from a total market perspective, the industry is not likely to possess any substantial market power advantage in being able to pass compliance costs through to customers as price increases.

Table B2E-11: Import Share and Export Dependence for the Profiled Aluminum Segments

Year	Value of Imports (millions, $2003)	Value of Exports (millions, $2003)	Value of Shipments (millions, $2003)	Implied Domestic Consumption[a]	Import Penetration[b]	Export Dependence[c]
Primary Aluminum Production						
1993[d]	2,570	647	6,181	8,104	31.7%	10.5%
1994[d]	4,073	627	6,533	9,979	40.8%	9.6%
1995[d]	4,233	791	7,660	11,102	38.1%	10.3%
1996[d]	3,422	768	6,679	9,333	36.7%	11.5%
1997[d]	3,876	671	6,893	10,098	38.4%	9.7%
1997[e]	3,892	688	6,893	10,097	38.5%	10.0%
1998[e]	4,075	597	6,803	10,281	39.6%	8.8%
1999[e]	4,193	648	6,272	9,817	42.7%	10.3%
2000[e]	4,435	656	6,369	10,148	43.7%	10.3%
2001[e]	4,152	474	5,707	9,385	44.2%	8.3%
Total Percent Change 1993-2001	*61.6%*	*-26.7%*		*15.8%*		*-20.7%*
Average Annual Percent Change	*5.5%*	*-3.4%*		*1.6%*		*-2.5%*
Aluminum Sheet, Plate, and Foil						
1993[d]	1,001	1,770	14,401	13,632	7.3%	12.3%
1994[d]	1,267	2,162	13,479	12,584	10.1%	16.0%
1995[d]	1,885	3,004	13,024	11,905	15.8%	23.1%
1996[d]	1,444	2,681	11,563	10,326	14.0%	23.2%
1997[d]	1,682	3,041	12,381	11,022	15.3%	24.6%
1997[e]	1,402	2,670	15,938	14,670	9.6%	16.8%
1998[e]	1,502	2,507	14,231	13,226	11.4%	17.6%
1999[e]	1,521	2,354	15,179	14,346	10.6%	15.5%
2000[e]	1,672	2,372	14,297	13,597	12.3%	16.6%
2001[e]	1,466	2,071	13,833	13,228	11.1%	15.0%
Total Percent Change 1993-2001	*46.5%*	*17.0%*		*-3.0%*		*21.8%*
Average Annual Percent Change	*4.3%*	*1.8%*		*-0.3%*		*2.2%*

[a] Calculated by EPA as shipments + imports - exports.
[b] Calculated by EPA as imports divided by implied domestic consumption.
[c] Calculated by EPA as exports divided by shipments.
[d] As no Census Trade data is available before 1997, Export and Import values are taken from USGS Mineral Yearbooks for years 1993-1997. "Metals and Alloys, Crude" represent SIC 3334 and "Plate, Sheets, Bars, Strip, etc." is equivalent to SIC 3353.
[e] Before 1998, the Department of Commerce compiled data in the SIC system; since 1998, these data have been compiled in the North American Industry Classification System (NAICS). For this analysis, EPA converted the NAICS classification data to the SIC code classifications using the 1997 Economic Census *Bridge Between NAICS and SIC*.

Source: ASM 1997-2001 USGS 1993c-1997c.

Table B2E-12 shows trends in exports and imports separately for aluminum metal and alloys and for semifinished products separately. U.S. aluminum companies have a large overseas presence, which makes it difficult to analyze import data. Reported import data may reflect shipments from an overseas facility owned by a U.S. firm. The import data therefore do not provide a completely accurate picture of the extent to which foreign companies have penetrated the domestic market for aluminum. This table shows that imports have grown substantially in both categories between 1993 and 2003. Exports of primary aluminum have generally declined, with some fluctuation over the period. Exports to semifinished aluminum rose steadily until 1999, where they peaked for the period, and have since declined.

Table B2E-12: Trade Statistics for Aluminum and Semifabricated Aluminum Products (Quantities in thousand metric tons; Values in $millions)

Year	Metals and Alloys, Crude				Plate, Sheets, Bars, Strip, etc.			
	Import[a]		Export[b]		Import[a]		Export[b]	
	Quantity	Value	Quantity	Value	Quantity	Value	Quantity	Value
1993	1,840	2,150	400	541	400	837	594	1,481
1994	2,480	3,480	339	536	507	1,082	719	1,847
1995	1,930	3,690	369	690	622	1,643	812	2,619
1996	1,910	3,040	417	682	498	1,283	760	2,382
1997	2,060	3,500	352	606	562	1,519	882	2,746
1998	2,400	3,660	265	449	649	1,715	893	2,723
1999	2,650	3,760	318	515	735	1,777	907	2,564
2000	2,490	4,030	273	468	791	2,088	845	2,380
2001	2,560	3,930	192	320	683	1,762	751	2,120
2002	2,790	4,040	206	337	796	1,922	706	1,880
Total Percent Change 1993-2002	*51.6%*	*87.9%*	*-48.5%*	*-37.7%*	*99.0%*	*129.6%*	*18.9%*	*26.9%*
Average Annual Growth Rate	*4.7%*	*7.3%*	*-7.1%*	*-5.1%*	*7.9%*	*9.7%*	*1.9%*	*2.7%*

Source: USGS 1994c-2002c.
[a]Table 10: U.S. Imports for Consumption of Aluminum, by Class
[b]Table 9: U.S. Exports of Aluminum, by Class

B2E-4 FINANCIAL CONDITION AND PERFORMANCE

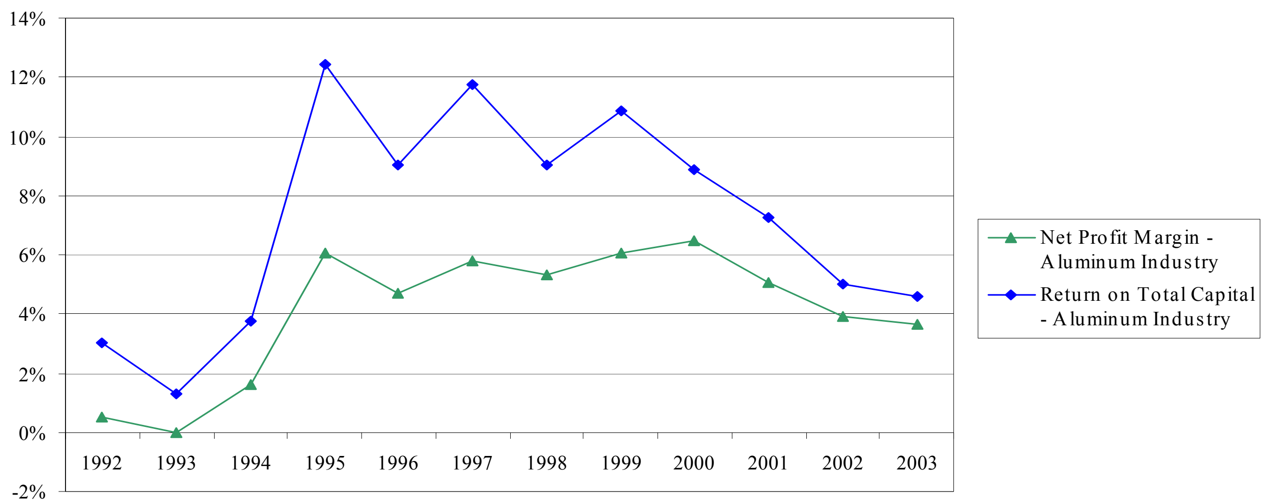
The financial performance and condition of the aluminum industry are important determinants of its ability to withstand the costs of regulatory compliance without material adverse economic/financial impact. To provide insight into the industry's financial performance and condition, EPA reviewed two key measures of financial performance over the 12-year period, 1992-2003: net profit margin and return on total capital. EPA calculated these measures as a revenue-weighted index of measure values for public reporting firms in the respective industries, using data from the Value Line Investment Survey. Financial performance in the most recent financial reporting period (2003) is obviously not a perfect indicator of conditions at the time of regulatory compliance. However, examining the trend, and deviation from the trend, through the most recent reporting period gives insight into where the industry *may be*, in terms of financial performance and condition, at the time of compliance. In addition, the volatility of performance against the trend, in itself, provides a measure of the *potential* risk faced by the industry in a future period in which compliance requirements are faced: all else equal, the more volatile the historical performance, the more likely the industry *may* be in a period of relatively weak financial conditions at the time of compliance.

Net profit margin is calculated as after-tax income before nonrecurring gains and losses as a percentage of sales or revenues, and measures profitability, as reflected in the conventional accounting concept of net income. Over time, the firms in an industry, and the industry collectively, must generate a sufficient positive profit margin if the industry is to remain economically viable and attract capital. Year-to-year fluctuations in profit margin stem from a several factors, including: variations in aggregate economic conditions (including international and U.S. conditions), variations in industry-specific market conditions (e.g., short-term capacity expansion resulting in overcapacity), or changes in the pricing and availability of inputs to the industry's production processes (e.g., the cost of energy to the aluminum production process). The extent to which these fluctuations affect an industry's profitability, in turn, depends heavily on the fixed vs. variable cost structure of the industry's operations. In a capital intensive industry such as the aluminum industry, the relatively high fixed capital costs as well as other fixed overhead outlays, can cause even small fluctuations in output or prices to have a large positive or negative affect on profit margin.

Return on total capital is calculated as annual net profit, plus one-half of annual long-term interest, divided by the total of shareholders' equity and long-term debt (total capital). This concept measures the total productivity of the capital deployed by a firm or industry, regardless of the financial source of the capital (i.e., equity, debt, or liability element). As such, the return on total capital provides insight into the profitability of a business' assets independent of financial structure and is thus a "purer" indicator of asset profitability than return on equity. In the same way as described for *net profit margin*, the firms in an industry, and the industry collectively, must generate over time a sufficient return on capital if the industry is to remain economically viable and attract capital. The factors causing short-term variation in *net profit margin* will also be the primary sources of short-term variation in *return on total capital*.

Figure B2E-7 below shows net profit margin and return on total capital for the aluminum industry between 1992 and 2003. The graph shows considerable volatility. Performance was very low between 1988 and 1993, reflecting general economic weaknesses and oversupply in the market (McGraw-Hill, 2000). By the mid-1990s, performance improved as demand recovered and aluminum prices increased. Performance declined again though in 2000 through 2002, reflecting economic downturn in both the U.S. and world economies. By 2003, financial performance began to level off compared to the significant declines experienced in the three prior years. Improving financial performance on a quarter-to-quarter basis over the course of 2003 suggests that the Aluminum industry is in position for improving financial performance in 2004 and beyond as U.S. economic conditions continue to strengthen.

Figure B2E-7: Net Profit Margin and Return on Total Capital for the Aluminum Industry



Source: Value Line, 1992-2003.

B2E-5 FACILITIES OPERATING COOLING WATER INTAKE STRUCTURES

Section 316(b) of the Clean Water Act applies to point source facilities that use or propose to use a cooling water intake structure and that withdraws cooling water directly from a surface waterbody of the United States. In 1982, the Primary Metals industries as a whole (including Steel and Non-ferrous producers) withdrew 1,312 billion gallons of cooling water, accounting for approximately 1.7 percent of total industrial cooling water intake in the United States[4]. The industry ranked 3rd in industrial cooling water use, behind the electric power generation industry, and the chemical industry (1982 Census of Manufactures).

This section provides information for facilities in the profiled aluminum segments potentially subject to the proposed regulation. Existing facilities that meet all of the following conditions are potentially subject to the proposed regulation:[5]

- 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;

- Have an National Pollutant Discharge Elimination System (NPDES) permit or are required to obtain one; and

- Have a design intake flow of greater than 2 million gallons per day (MGD).

The proposed regulation 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 section focuses on the 21

[4] Data on cooling water use are from the *1982 Census of Manufactures*. 1982 was the last year in which the Census of Manufactures reported cooling water use.

[5] The proposed Phase III regulation also applies to existing electric generating facilities as well as certain facilities in the oil and gas extraction industry and the seafood processing industry. See Chapters B4 and B5 and Part C of this document for more information on these industries.

facilities nation-wide in the profiled aluminum segments identified in EPA's 2000 Section 316(b) Industry Survey as being potentially subject to this proposed regulation[6]. Information collected in the Detailed Industry Questionnaire found that an estimated 11 out of 31 Primary Aluminum producers (36 percent) and 10 out of 57 Aluminum Sheet, Plate, and Foil manufacturers (18 percent) meet the characteristics of a potential Phase III facility.

B2E-5.1 Waterbody and Cooling System Type

Table B2E-13 shows the distribution of potential Phase III facilities in the profiled aluminum segment by type of water body and cooling system. The table shows that three-quarters of the potential Phase III facilities use a once-through cooling system (16, or 77%) and one-quarter use a recirculating system (5, or 23%). Ten of the 11 Section 316(b) Primary Aluminum producers obtain their cooling water from a freshwater stream or river. The other Section 316(b) Primary Aluminum producer draws from a lake or reservoir. Seven of the Section 316(b) Aluminum Sheet, Plate, and Foil manufacturers obtain their cooling water from either a freshwater stream or river. The other three Section 316(b) Aluminum Sheet, Plate, and Foil manufacturers draw from one of the Great Lakes. Seventy-six percent (16 facilities) of all Section 316(b) aluminum facilities withdraw their cooling water from a freshwater stream or river. None of the facilities withdraw from an estuary, the most sensitive type of waterbody.

Table B2E-13: Number of Potential Phase III facilities by Water Body Type and Cooling System Type for the Profiled Aluminum Segments

Water Body Type	Cooling System				Total
	Recirculating		Once-Through		
	Number	% of Total	Number	% of Total	
Primary Production of Aluminum					
Freshwater Stream or River	0	0%	10	100%	10
Lake or Reservoir	1	100%	0	0%	1
Total	*1*	*9%*	*10*	*91%*	*11*
Aluminum Sheet, Plate, and Foil					
Freshwater Stream or River	3	43%	3	47%	7
Great Lake	0	0%	3	100%	3
Total	*3*	*30%*	*7*	*70%*	*10*
Total for Profiled Aluminum Facilities					
Freshwater Stream or River	3	18%	13	82%	16
Lake or Reservoir	1	100%	0	0%	1
Great Lake	0	0%	3	100%	3
Total	**5**	**24%**	**16**	**78%**	**21**

Source: U.S. EPA, 2000.

[6] EPA applied sample weights to the sampled 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).

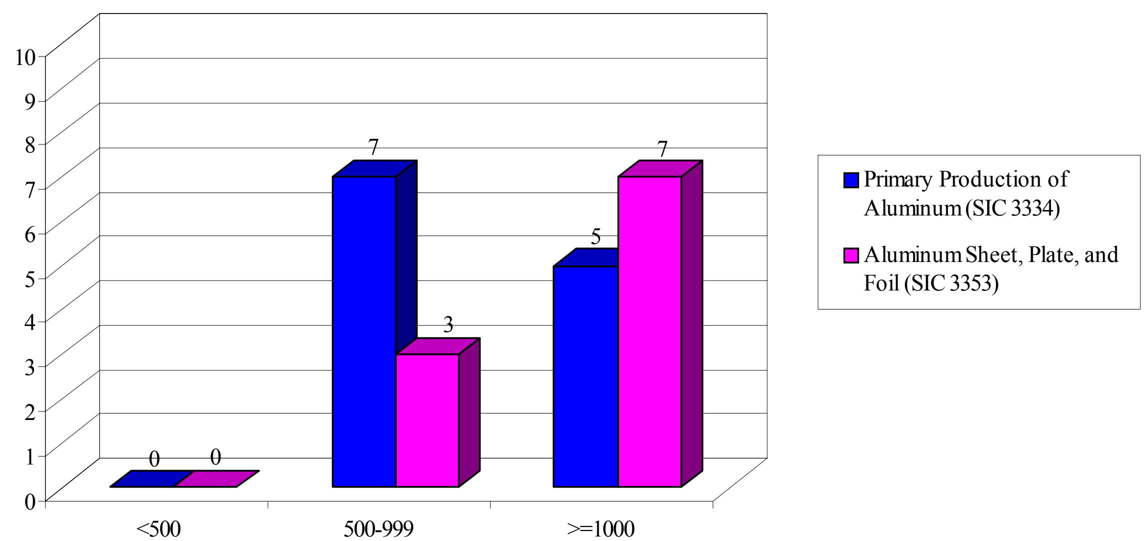
B2E-5.2 Facility Size

Section 316(b) sample aluminum facilities are larger than facilities in their industries as a whole, as reported in the Census and discussed previously:

- Sixty-five percent of all facilities in the aluminum segment had fewer than 500 employees in 1992; none of the potential Phase III facilities in that segment fall into that employment category.

Figure B2E-8 shows the number of potential Phase III facilities by employment size category.

Figure B2E-8: Number of Potential Phase III facilities by Employment Size for the Profiled Aluminum Segments



Source: U.S. EPA, 2000.

B2E-5.3 Firm Size

EPA used the Small Business Administration (SBA) small entity size standards to determine the number of existing Section 316(b) profiled aluminum industry facilities owned by small firms. Firms in the Primary Production of Aluminum segment are defined as small if they have 1000 or fewer employees; firms in the Aluminum Sheet, Plate, and Foil segment are defined as small if they have 750 or fewer employees. Table B2E-14 shows that three (or 27 percent) of the Section 316(b) Primary Aluminum producers are owned by small firms. The remaining eight (or 73 percent) Primary Aluminum producers are owned by large firms. All of the Section 316(b) Aluminum Sheet, Plate, and Foil producers are owned by large firms.

Table B2E-14: Number of Potential Phase III facilities by Firm Size for the Profiled Aluminum Segments

SIC Code	Large		Small		Total
	Number	% of SIC	Number	% of SIC	
3334	8	73%	3	27%	11
3353	10	100%	0	0%	10
Total	*18*	*86%*	*3*	*14%*	*21*

Source: U.S. EPA, 2000; U.S. SBA, 2000; D&B, 2001.

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Chapter B2F: Facilities in Other Industries (Various SICs)

CHAPTER CONTENTS

The preceding profile sections focus on the five Primary Manufacturing Industries – Paper and Allied Products, Chemicals and Allied Products, Petroleum and Coal Products, Steel, and Aluminum – identified, after electric power generators, as using the largest amount of cooling water in their operations and most likely, after electric power generators, to be subject to the proposed regulation. However, facilities in other industries use cooling water and would therefore also be subject to the proposed regulation if they meet the regulation's specifications. This section of the profile provides information on a sample of facilities in these Other Industries.

Although EPA targeted its *Detailed Industry Questionnaire* at the electric power industry and the five Primary Manufacturing Industries, the Agency received 22 questionnaire responses from facilities with business operations in industries other than these major cooling water-intensive industries. EPA originally believed these facilities to be non-utility electric power generators; however, inspection of their responses indicated that the facilities were better understood as cooling water-dependent facilities whose principal operations lie in businesses other than the electric power industry or the Primary Manufacturing Industries. Unlike the sample facility observations for the five Primary Manufacturing Industries, the sample of observations from Other Industries is not based on a scientifically framed sample and the information from this sample of observations may not be reliably extrapolated beyond these facilities. As a result, EPA's profile of information for the Other Industries facilities is restricted to these 22 sample facilities and is not presented as national estimates.

The 22 Other Industries facilities fall in a wide range of businesses, as defined by 2-digit SIC industry group. Table B2F-1, following page, presents the number of responses received from facilities in the Other Industries by industry group.

Table B2F-1: Facility Observations in Other Industries by 2-digit SIC code

No. of Facilities	SIC Code	SIC Description	Important Operations
1	01	Agriculture production - crops	Crops, plants, vines, and trees (excluding forestry operations); sod farms, and cranberry bogs; mushrooms, bulbs, flower seeds, and vegetable seeds; and growing of hydroponic crops.
3	10	Metal mining	Mining, developing mines, or exploring for metallic minerals (ores); ore dressing and beneficiating operations, whether performed at mills operated in conjunction with the mines served or at mills, such as custom mills, operated separately.
1	14	Mining and quarrying of nonmetallic minerals, except fuels	Mining or quarrying, developing mines, or exploring for nonmetallic minerals, except fuels; certain well and brine operations, and primary preparation plants, such as those engaged in crushing, grinding, washing, or other concentration
12	20	Food and kindred products	Manufacturing or processing foods and beverages for human consumption, and certain related products, such as manufactured ice, chewing gum, vegetable and animal fats and oils, and prepared feeds for animals and fowls.
1	22	Textile mill products	Preparation of fiber and subsequent manufacturing of yarn, thread, braids, twine, and cordage; manufacturing broadwoven fabrics, narrow woven fabrics, knit fabrics, and carpets and rugs from yarn; dyeing and finishing fiber, yarn, fabrics, and knit apparel; coating, waterproofing, or otherwise treating fabrics; integrated manufacture of knit apparel and other finished articles from yarn; manufacture of felt goods, lace goods, non-woven fabrics, and miscellaneous textiles.
2	24	Lumber and wood products, except furniture	Cutting timber and pulpwood; merchant sawmills, lath mills, shingle mills, cooperage stock mills, planing mills, and plywood mills and veneer mills engaged in producing lumber and wood basic materials; manufacturing finished articles made entirely or mainly of wood or related materials.
1	34	Fabricated metal products, except machinery and transportation equipment	Ferrous and nonferrous metal products, such as metal cans, tinware, handtools, cutlery, general hardware, nonelectric heating apparatus, fabricated structural metal products, metal forgings, metal stampings, ordnance (except vehicles and guided missiles), and a variety of metal and wire products, not elsewhere classified.
1	37	Transportation equipment	Equipment for transportation of passengers and cargo by land, air, and water.

Source: U.S. EPA, 2000; Executive Office of the President, 1987.

B2F-1 FACILITIES OPERATING COOLING WATER INTAKE STRUCTURES

Section 316(b) of the Clean Water Act applies to point source facilities that use or propose to use a cooling water intake structure and that withdraws cooling water directly from a surface waterbody of the United States. This section provides information for facilities in Other Industries potentially subject to the proposed regulation. The proposed regulation applies to existing facilities that meet all of the following conditions:[1]

- 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;

[1] The proposed Phase III regulation also applies to existing electric generating facilities as well as certain facilities in the oil and gas extraction industry and the seafood processing industry. See Chapters B4 and B5 and Part C of this document for more information on these industries.

- Have an National Pollutant Discharge Elimination System (NPDES) permit or are required to obtain one; and

- Have a design intake flow of greater than 2 million gallons per day (MGD).

The proposed regulation 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 section focuses on the 22 facilities nation-wide in Other Industries identified in EPA's 2000 Section 316(b) Industry Survey as being potentially subject to this proposed regulation.

B2F-1.1 Waterbody and Cooling System Types

Table B2F-2 reports the distribution of the Other Industries facilities by type of water body and cooling system. The majority of these facilities have either a once-through system (10, or 46 percent) or recirculating system (7, or 33 percent). In addition, a majority of these facilities draw water from a freshwater stream or river (12, or 55 percent). Of the four facilities that withdraw from an estuary, the most sensitive type of waterbody, three use a once-through cooling system. Plants with once-through cooling water systems withdraw between 70 and 98 percent more water than those with recirculating systems.

Table B2F-2: Number of Sampled Facilities by Water Body and Cooling System Type for Facilities in Other Industries

Water Body Type	Cooling System								
	Recirculating		Combination		Once-Through		Other		Total[a]
	Number	% of Total	Number	% of Total	Number	% of Total	Number	% of Total	
Other Industries									
Freshwater Stream/ River	6	50%	1	8%	3	25%	2	17%	12
Estuary/ Tidal River	1	25%	0	0%	3	75%	0	0%	4
Lake / Reservoir	0	0%	0	0%	1	100%	0	0%	1
Great Lake	0	0%	2	50%	2	50%	0	0%	4
Ocean	0	0%	0	0%	1	100%	0	0%	1
Total[a]	***7***	***32%***	***3***	***14%***	***10***	***45%***	***2***	***9%***	22

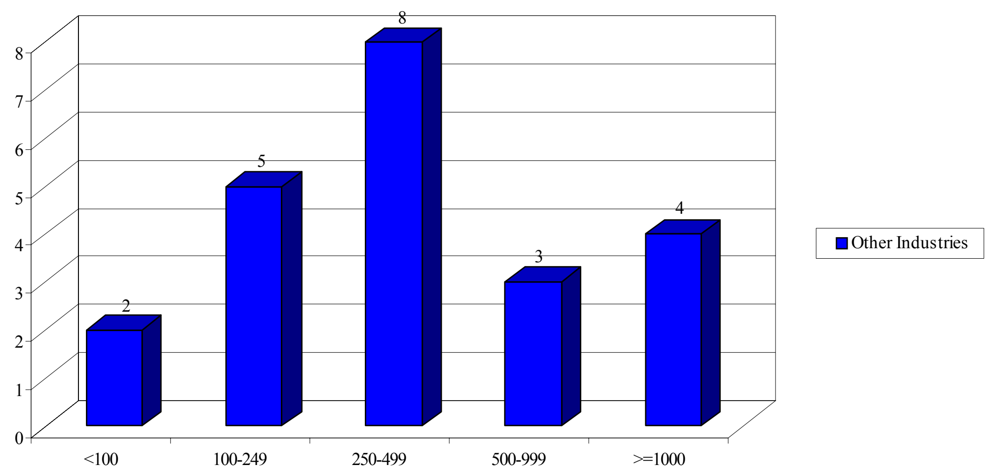
[a] Individual numbers may not add up to total due to independent rounding.

Source: U.S. EPA, 2000.

B2F-1.2 Facility Size

Figure B2F-1 shows the employment size category for the 22 sampled facilities identified as having primary operations outside of the power generation and Primary Manufacturing Industries already profiled. Half of the sampled facilities have between 100 and 500 employees and five have over 1,000 employees.

Figure B2F-1: Number of Sampled Facilities in Other Industries by Employment Size



Source: U.S. EPA, 2000.

B2F-1.3 Firm Size

EPA used the Small Business Administration (SBA) small entity size standards to determine the number of sampled facilities in Other Industries that are owned by small firms. Depending on their SIC code, firms are defined as small based on either revenues or number of employees. Table B2F-3 shows that Section 316(b) facilities in Other Industries are predominantly owned by large firms. Overall, 19 facilities (86 percent) are owned by large firms, and 3 facilities (14 percent) are owned by small firms.

Table B2F-3: Number of Sampled Section 316(b) Facilities in Other Industries by Firm Size

	Large	Small	Total
Other Industries	19	3	22

Source: U.S. EPA, 2000; U.S. SBA, 2000; D&B, 2001.

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Executive Office of the President. 1987. Office of Management and Budget. *Standard Industrial Classification Manual.*

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GLOSSARY

Capital expenditures: As reported in the Economic Censuses, reflects permanent additions and major alterations, as well as replacements and additions to capacity, for which depreciation, depletion, or Office of Minerals Exploration accounts are ordinarily maintained. Reported capital expenditures include work done on contract, as well as by the mine forces. Totals for expenditures include the costs of assets leased from other concerns through capital leases. Excluded are expenditures for land and cost of maintenance and repairs charged as current operating expenses. Also excluded are capital expenditures for mineral land and rights which are shown as a separate item.

Capacity utilization: Indicates the extent to which plant capacity is being used and shows potential excess or insufficient capacity. This profile reports capacity utilization as published by the U.S. Bureau of Census in the Survey of Plant Capacity published in the Current Industrial Reports. The utilization rate is equal to an output index divided by a capacity index. Output is measured by seasonally adjusted indexes of industrial production, and is based on actual output in 1992. The capacity indexes attempt to capture the concept of sustainable practical capacity, which is defined as the greatest level of output that a plant can maintain within the framework of a realistic work schedule, taking account of normal downtime, and assuming sufficient availability of inputs to operate the machinery and equipment in place.

Concentration ratio: The combined percentage of total industry output accounted for by the largest producers in the industry. For example, the four-firm concentration ratio (CR4) refers to the market share of the four largest firms. The higher the concentration ratio, the more concentrated the industry. A market is generally considered highly concentrated if the CR4 is greater than 50 percent.

Coverage ratio: The ratio of primary products shipped by the establishments classified in the industry to the total shipments of such products that are shipped by all manufacturing establishments, wherever classified. An industry with a high coverage ratio accounts for most of the value of shipments of its primary products, whereas an industry with a low coverage ratio produces a smaller portion of the total value of shipments of its primary products produced by all sources.

Employment: Total number of full-time equivalent employees, including production workers and non-production workers.

Export dependence: The share of shipments by domestic producers that is exported; calculated by dividing the value of exports by the value of domestic shipments.

Herfindahl-Hirschman index (HHI): An alternative measure of concentration. Equal to the sum of the squares of the market shares for the largest 50 firms in the industry. The higher the index, the more concentrated the industry. The Department of Justice uses the HHI for antitrust enforcement purposes. The benchmark used by DOJ is 1,000, where any industry with an HHI less than 1,000 is considered to be unconcentrated. The advantage of the HHI over the concentration ratio is that the former gives information about the dispersion of market share among all the firms in the industry, not just the largest firms (Arnold, 1989).

Import penetration: The share of all consumption in the U.S. that is provided by imports; calculated by dividing imports by reported or apparent domestic consumption (the latter calculated as domestic value of shipments minus exports plus imports).

Labor productivity: Amount of output produced per unit of labor input on average. Calculated in this profile as real value added divided by production hours. This measure indicates how an industry uses labor as an input in the production process. Changes over time in labor productivity may reflect changes in the relative use of labor versus other inputs to produce output, due to technological changes or cost-cutting efforts. Changing patterns of labor utilization relative to output are particularly important in understanding how regulatory requirements may translate into job losses, both in aggregate and at the community level.

Nominal values: Dollar values expressed in current dollars.

Operating margin: Measure of the relationship between input costs and the value of production, as an indicator of financial performance and condition. Everything else being equal, industries and firms with lower operating margins will generally have less flexibility to absorb the costs associated with a regulation than those with higher operating margins. Operating margins were calculated in this profile by subtracting the cost of materials and total payroll from the value of shipments. Operating margin is only an approximate measure of profitability, since it does not consider capital costs and other costs. It is used to examine trends in revenues compared with production costs within an industry; it should not be used for cross-industry comparisons of financial performance.

Primary product shipments: An establishment is classified in a particular industry (4-digit SIC codes) if its shipments of the primary products of that industry exceed in value its shipments of the products of any other single industry. An establishment's primary product shipments are those products considered primary to its industry.

Producer production indexes (PPI): A family of indexes that measures the average change over time in selling prices received by domestic producers of goods and services (Bureau of Labor Statistics, PPI Overview). Used in this profile to convert nominal values into real 1997 dollar values.

Real values: Nominal values normalized using a price index to express values in a single year's dollars. Removes the effects of price inflation when evaluating trends in dollar measures.

Secondary product shipments: An establishment's products that are considered secondary to the industry in which the establishment is classified and primary to other industries. For example, a petroleum refinery classified in SIC code 2911 would produce petroleum products as primary products, but might produce organic chemicals as secondary products.

Value added: A measure of manufacturing activity, derived by subtracting the cost of purchased inputs (materials, supplies, containers, fuel, purchased electricity, contract work, and contract labor) from the value of shipments (products manufactured plus receipts for services rendered), and adjusted by the addition of value added by merchandising operations (i.e., the difference between the sales value and the cost of merchandise sold without further manufacture, processing, or assembly) plus the net change in finished goods and work-in-process between the beginning-and end-of-year inventories. Value added avoids the duplication in value of shipments as a measure of economic activity that results from the use of products of some establishments as materials by others. Value added is considered to be the best value measure available for comparing the relative economic importance of manufacturing among industries and geographic areas.

Value of shipments: Net selling values of all products shipped as well as miscellaneous receipts. Includes all items made by or for an establishments from materials owned by it, whether sold, transferred to other plants of the same company, or shipped on consignment. Value of shipments is a measure of the dollar value of production, and is often used as a proxy for revenues. This profile uses value of shipments to indicate the size of a market and how the size differs from year to year, and to calculate operating margins.

Chapter B3: Economic Impact Analysis for Manufacturers

INTRODUCTION

This chapter assesses the expected economic effect of the proposed section 316(b) Regulation for Phase III Facilities on the Manufacturers that would be subject to national categorical requirements under the proposed regulation. The analysis focuses on impacts in five key manufacturing industries – Paper, Chemicals, Petroleum, Aluminum, Steel (the "Primary Manufacturing Industries") – in which a substantial number of ***facilities*** are expected to be subject to the proposed regulation. EPA's analysis of the regulation's expected impact in these industries is based on a statistically valid sample survey of facilities in these five industries. The sample survey indicates that the regulation would potentially subject as many as 532 facilities in the Primary Manufacturing Industries[1] to national requirements.

CHAPTER CONTENTS

This chapter also considers the effect of the regulation on facilities in other industries ("Other Industries") that are expected to be within the scope of the regulation. The facility impact analysis for Other Industries is restricted to a sample of 22 facilities for which EPA received surveys, but which are not part of the statistically valid sample. As a result, EPA's analysis for the Other Industries group is limited to these known facilities. EPA has not estimated the number of facilities in the Other Industries group that may be subject to the regulation because EPA does not believe that this number can be reliably extrapolated from the sample of known facilities in this group. However, because the statistically valid survey group of six industries (i.e., for the five Primary Manufacturing Industries and Electric Generators) reflects 99% of total cooling water withdrawals, EPA believes that few additional facilities in the Other Industries group are potentially subject to the proposed regulation.

Although EPA was able to undertake impact analysis for the Other Industries group using only the sample of known facilities for this group, EPA believes that its analysis for the Other Industries group provides a sufficient basis for regulation development. EPA's review of the engineering characteristics of cooling water intake and use in the Other Industries group indicates that cooling water intake and use in these industries do not differ materially from cooling water intake and use in the electric power industry and the Primary Manufacturing Industries. In addition, EPA specifically analyzed the economic impacts of the three proposed options on the 22 sample facilities in the Other Industries group and found no economic impact of the proposed options on these facilities. For these reasons, EPA believes that its findings of no economic impact to the known facilities in the Other Industries group, and thus the practicability of the three proposed options, are generally applicable to the full breadth of industries, including the Other Industries group, within the regulation's scope.

Based on the sum of the sample-weighted estimate of 532 facilities in the Primary Manufacturing Industries and the 22 known facilities in the Other Industries group, EPA included a total of 554 potentially regulated facilities

[1] EPA applied sample weights to 199 sample 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).

in the economic impact analysis for the Manufacturers segment. The total number of Manufacturers segment facilities considered in the economic impact analysis (554) differs from the number of facilities potentially subject to regulation (566), as reported in Chapter A1. EPA determined that the survey responses of 14 sample facilities lacked certain financial data needed for the facility impact analysis while containing sufficient data to support estimates of facility counts and compliance costs. EPA therefore retained these sample facilities (37 sample weighted facilities) in the analyses to estimate the total number of Manufacturers facility potentially subject to regulation but excluded them from the economic impact analysis. When these sample facilities were excluded from the impact analysis, the sample weights for remaining facilities within the affected sample frames were adjusted upwards to account for their removal. The difference in the reported facility totals in the impact and social cost analyses reflects the removal of these 14 facilities and the use of adjusted sample weights. The removal of specific sample facilities from the analysis universe and simultaneous adjustment of sample weights to account for their removal yields the same estimate of the total *combined* population of Manufacturers and Electric Generators for the analysis. However, as a result of the sample stratification methodology, the estimates of the total facility populations *for Manufacturers only* differ slightly between the two sample facility cases. Both values are valid statistical estimates of the same, but unknown, value of the Manufacturers facility population.

EPA undertook the economic impact analysis to aid in assessing the economic achievability of alternative regulatory options and, on the basis of that assessment, to aid in defining the proposed regulation. Measures of economic impact include facility closures and associated losses in employment, financial stress short of closure ("moderate impacts"), and firm-level impacts. ***Severe impacts*** are facility closures and the associated losses in jobs at facilities that close due to the regulation. EPA also assessed moderate economic impacts to support its evaluation of regulatory options and to understand better the regulation's economic impacts. ***Moderate impacts*** are adverse changes in a facility's financial position that are not threatening to its short-term viability. The firm impact analysis assesses whether firms that own multiple facilities are likely to incur more significant impacts than indicated by the facility impact analysis. Impacts may be more significant at the firm level than at the facility level if a firm owns a number of facilities that incur significant cost. In addition, a firm-level analysis is needed to assess impacts on small businesses, as required by the Regulatory Flexibility Act and SBREFA. Other chapters consider the impacts on small entities (*Chapter D1: Regulatory Flexibility Analysis*) and impacts on governments (*Chapter D2: UMRA Analysis*).

This chapter presents the impact analysis results for the three proposed options: the "50 MGD for All Waterbodies" option ("50 MGD All"), the "200 MGD for All Waterbodies" option ("200 MGD All"), and the "100 MGD for Certain Waterbodies" Option ("100 MGD CWB"). These options differ with regard to (1) their design intake flow (DIF) applicability thresholds (50, 100, and 200 MGD, respectively); and (2) the type of waterbodies to which they would apply (the options with the 50 and 200 MGD applicability thresholds would apply to all waterbody types while the 100 MGD applicability threshold option would apply only to certain waterbody types – an ocean, estuary, tidal river/stream, or one of the Great Lakes). Facilities meeting these applicability criteria would be required to meet similar requirements to those required in the final Phase II regulation, including a 80-95% reduction in impingement mortality and a 60-90% reduction in entrainment. Facilities not meeting these criteria would continue to be subject to 316(b) requirements established by permit writers based on their Best Professional Judgment (BPJ). As a result, the number of facilities required to meet the national categorical requirements would vary under each of the three proposed options. Of the three options presented here, the 100 MGD for Certain Waterbodies Option would subject the smallest number of facilities to national categorical requirements, with the 200 MGD for All Waterbodies Option and 50 MGD for All Waterbodies Option subjecting successively larger numbers of facilities to national requirements.

As outlined in *Chapter A1: Introduction*, EPA considered several additional regulatory options based on varying flow regimes and waterbody types, in arriving at the proposed options. Summary results for five additional options can be found in Appendix 1 to this chapter.

This chapter describes the methodology used to assess economic impacts for the Manufacturers facilities, and presents the results of the analyses.

B3-1 DATA SOURCES

The economic impact analyses rely on data provided in the financial portion of the detailed questionnaires distributed by EPA to facilities potentially subject to the Phase III regulation under the authority of Section 308 of the Clean Water Act. The survey financial data included facility and parent firm income statements and balance sheets for the three years 1996, 1997, and 1998.

In addition to the survey data, a number of secondary sources were used to characterize economic and financial conditions in the industries subject to the proposed Phase III regulation. Secondary sources used in the analyses include:

- Department of Commerce economic census and survey data, including the *Census of Manufactures, Annual Surveys of Manufactures,* and international trade data;
- U.S. *Industry and Trade Outlook*, published by McGraw-Hill and the U.S. Department of Commerce;
- Value Line Investment Survey;
- *Annual Statement Studies*, published by Risk Management Association (RMA); and
- Statistics of U.S. Businesses (SUSB).

B3-2 METHODOLOGY

The impact analysis starts with compliance cost estimates from the EPA engineering analysis and then calculates how these compliance costs would affect the financial condition of Section 316(b) Manufacturers. EPA included the following compliance cost categories in this analysis: capital cost, annual ***operating and maintenance*** cost, administrative cost, and the loss of business income from potential shutdown of facilities during installation of compliance equipment[2]. Of these cost categories, only operating and maintenance and certain administrative costs recur annually. The remaining costs occur only once at the beginning of compliance or on a multi-year interval over the period of the compliance analysis. Some of the impact analyses require combining the annually recurring and non-recurring costs into a single, annual equivalent value. For combining the annually recurring and non-recurring costs in this analysis, EPA calculated the annual equivalent cost of the non-recurring cost categories and added these *annualized* costs to the annually recurring operating and maintenance cost.

To derive the constant annual value of the non-annual costs, EPA annualized each cost component over the component's estimated useful life, using a 7.0% discount rate. The cost of compliance equipment, which includes fine-mesh traveling screens, with and without fish handling, and fish handling and return systems, was annualized over 10 years; initial permitting cost and the income loss from installation shutdown were annualized over 30 years; and repermitting cost was annualized over 5 years[3]. For more information on the compliance cost components developed for this analysis, see *Chapter B1: Summary of Cost Categories and Key Analysis Elements for Existing Facilities* and the *§ 316(b) Technical Development Document* (U.S. EPA, 2004).

[2] See Appendix 2 to Chapter B3 for details of the downtime cost calculation.

[3] The annualization approach used for the facility impact analysis differs from that used to develop the social cost estimate presented in *Chapter B1: Summary of Cost Categories and Key Analysis Elements for Existing Facilities*. For the analysis of the social cost of the proposed regulation, the present value of total cost and the constant annual equivalent to that present value (annualized cost) were calculated as of the expected effectiveness date of the final regulation for Phase III facilities, beginning of year 2007. In contrast, for the impact analysis, the present value and annualized value of compliance cost were determined as of the first year of compliance of each facility (for this analysis, assumed to be 2010 to 2014).

As discussed in *Chapter B1: Summary of Cost Categories and Key Analysis Elements for Existing Facilities*, the various economic information used in this analysis were initially provided in dollars of different years. For example, facility financial data obtained in the 316(b) survey for Manufacturers are for the years 1996, 1997, and 1998, while the technology costs of regulatory compliance were estimated in dollars of the year 2002. To support a consistent analysis using these data that were initially developed in dollars of different years, EPA needed to bring the dollar values to a common analysis year. For this analysis, EPA adjusted all dollar values to constant dollars of the year 2003 (average or mid-year, depending on data availability) using an appropriate inflation adjustment index. For adjusting compliance costs, EPA used the ***Construction Cost Index (CCI)*** published by the Engineering News-Record. For financial statement information, EPA used the ***Gross Domestic Product Implicit Price Deflator (GDP Deflator)*** to bring dollar values to 2003. The values used to adjust the dollar values to constant dollars can be found in Chapter B1.

For the impact analysis, EPA first eliminated from analysis those facilities showing materially inadequate financial performance in the baseline, that is, in the absence of the regulation. EPA judged these facilities, which are referred to as ***baseline closures***, to be at substantial risk of financial failure regardless of any financial impacts of the 316(b) regulation. Second, for the remaining facilities, EPA evaluated how compliance costs would likely affect facility financial health. A facility is identified as a ***regulatory closure*** if it would have operated under baseline conditions but would fall below an acceptable financial performance level when subject to the new regulatory requirements.

EPA's analysis also identified facilities that would likely incur moderate impacts from compliance with the regulation. EPA anticipates that these facilities would experience moderate deterioration of financial performance but not at a level sufficient to cause the facility to fail financially. The test of moderate impacts examined two financial ratios – pre-tax return on assets and interest coverage ratio – calculated on a baseline and post-compliance basis. Incremental moderate impacts are attributed to the regulation if both financial ratios exceeded threshold values in the baseline (i.e., no moderate impacts in the baseline), but at least one financial ratio fell below the threshold value in the post-compliance case.

For the assessment of firm-level effects, EPA compared annualized after-tax compliance cost to firm revenue and reports the estimated number and percentage of firms incurring compliance cost in three cost-to-revenue ranges: less than 1.0%; at least 1.0% but less than 3.0%; and 3.0% or greater. Although EPA's sample-based data support specific estimates of the number of facilities, these data do not support a specific estimate of the number of entities that own these facilities. As a result, EPA estimated the number of entities owning facilities in the manufacturing industries as a range, based on alternative assumptions about the potential ownership of regulated facilities. In its comparison of compliance cost to firm revenue, EPA also used this same range concept, which yields approximate upper and lower bound estimates of the value of compliance cost that might be incurred by an entity, based on the number of regulated facilities that it owns.

Key steps in the facility- and firm-level impact methodologies are described in the following discussions. In addition, seven appendixes to this chapter provide detail of specific aspects of the impact analysis methodologies.

B3-2.1 Market-Level Impacts

Increased cost from the regulation may affect industry-level prices and output. In some instances, facilities incurring compliance costs may be able to pass part of these costs through to customers as price increases and thus reduce the compliance cost burden borne directly by complying facilities. On the basis of analysis presented in Appendix 3 to Chapter B3 and the findings from the industry profile analyses as discussed in the preceding chapter, *Chapter B2: Profile of Manufacturers*, EPA determined that an assumption of zero ***cost pass-through*** is appropriate for its analysis of the effect of the 316(b) regulation on manufacturing industries. The assumption of zero cost pass-through is conservative in that the analysis assumes that facilities must bear all compliance costs within baseline cash flow. Because facilities may be able to pass compliance costs through to consumers in some markets, this assumption may overstate impacts to affected facilities and understate the ability of facilities to withstand the cost of 316(b) regulatory compliance without material financial impact.

B3-2.2 Impact Measures

a. Test of Severe Impacts

The analysis of severe impacts estimates the number of facilities that could potentially close due to the regulation. EPA predicted that a facility would close if compliance costs cause the facility's overall financial performance and resulting implied financial value to fall below a specified threshold level.

The assessment of severe impacts for 316(b) manufacturing facilities is based on the change in the facility's estimated business value, as determined from a discounted present value analysis of baseline cash flow and the change in cash flow resulting from regulatory compliance. If the estimated discounted cash flow value of the facility is positive before considering the effects of regulatory compliance but becomes negative as a result of compliance outlays, then the facility is considered a regulatory closure. In this impact test, the estimated ongoing business value of the facility is compared with a threshold value of zero for the closure decision: as long as the discounted cash flow value of the facility is greater than zero, the business is earning its cost of invested capital and continuation of the business is warranted. If the discounted cash flow value of the facility is less than zero in the baseline or becomes less than zero as a result of compliance outlays, then the business would not earn its cost of invested capital and the business owners would be better off financially by terminating the business. As noted in earlier discussion, facilities for which EPA estimated a negative baseline value were considered baseline closures and were not tested for additional adverse impacts from regulatory compliance.

In an alternative, theoretically more accurate, formulation of this concept, business owners would compare the discounted cash flow value of the facility with the value that the facility's assets would bring in liquidation. In this case, the estimated ongoing business value would be compared with a value that may be different from zero: ***liquidation value*** could be positive or negative. When liquidation value is positive, business owners might benefit financially by terminating a business and seeking its liquidation value even when the ongoing business value is positive but less than the estimated liquidation value. With negative liquidation value – which generally would result from business termination liabilities (e.g., site clean-up) – the opposite result could occur: business owners may find it financially advantageous to remain in business *even though the business earns less than its cost of invested capital*, if the liquidation value of the business is "more negative", and thus less in value, than the ongoing business based on the discounted cash flow analysis. EPA attempted to implement this alternative impact test formulation. EPA judges that the liquidation value estimates are substantially speculative and subject to considerable error. For these reasons, EPA decided against using liquidation value for comparison with ongoing business value in the closure test.

The cash flow concept used in calculating ongoing business value for the closure analysis is ***free cash flow*** available to all capital. Free cash flow is the cash available to the providers of capital – both equity owners and creditors – on an after-tax basis from business operations, and takes into account the cash required for ongoing replacement of the facility's capital equipment. Free cash flow is discounted at an estimated after-tax total ***cost of capital*** to yield the estimated business value of the facility. Details of the calculation of free cash flow and the discounting of free cash flow to yield the facility's estimated value are explained in the following sections.

❖ ***Calculation of Baseline Free Cash Flow and Performance of Baseline Closure Test***

Calculation of baseline free cash flow and performance of the baseline closure test involved the following steps:

1. *Average survey income statement data over response years and convert to mid-year 2003 dollars:* EPA first adjusted facility income statement data for 1996, 1997, and 1998 to the year 1998, using the GDP Deflator. These data were then averaged over the months and/or years for which survey respondents reported data to develop an annual average income statement in 1998 constant dollars. For example, if a facility reported income statement data for 1996, 1997, and 1998, then a simple average was calculated for the three reported years. The annual average income statement in 1998 was then brought forward from 1998 to 2003, again using the GDP Deflator.

2. *Calculate after-tax income excluding the effects of financial structure:* The questionnaire responses include a calculation of after-tax income in accord with conventional accounting principles. However, this calculation reflects the financial structure of the business, which may include debt financing and thus interest charges against income. Because the cash flow concept to be discounted in the business value analysis is cash flow available to *all* capital, it is necessary to restate after-tax income to exclude the effects of debt financing, or on a *before-interest* basis. This restatement involves: (1) increasing after-tax income by the amount of interest charges and (2) increasing taxes (and thereby reducing after-tax income) by the amount of tax reduction provided by interest deductibility. This adjustment amounts to adding tax-adjusted interest expense to after-tax income and yields an estimate of after-tax income *independent of capital structure or financing effects*. In calculating the tax adjustment for interest, EPA used a combined federal/state corporate income tax rate. For this calculation, EPA used a tax rate that integrates the federal corporate income tax rate (35%) and state-specific state corporate income tax rates, based on facility location.

   The combined federal/state corporate income tax rate was calculated as follows:

   $$\tau = \tau_S + \tau_F - (\tau_S * \tau_F) \qquad \text{(B3-1)}$$

   where:
   τ = estimated combined federal-state tax rate;
   τ_S = state tax rate; and
   τ_F = federal tax rate (35%).

   After-tax income, *before interest,* was calculated as follows:

   $$\text{ATI-}BI = \text{ATI} + \text{I} - \tau\text{I} \textit{ or} \qquad \text{(B3-2)}$$
   $$\text{ATI-}BI = \text{ATI} + (1 - \tau)\text{I}$$

   where:
   ATI-*BI* = after-tax income *before interest*;
   ATI = after-tax income from baseline financial statement;
   I = interest charge from baseline financial statement; and
   τ = estimated combined federal-state tax rate.

3. *Calculate after-tax cash flow from operations, before interest, by adjusting income for non-cash charges:* The calculation of after-tax income may include a non-cash charge for depreciation (and potentially amortization). To convert income to ***after-tax cash flow (ATCF)*** from operations, it is therefore necessary to add back any depreciation charge to the calculation of after-tax income, before interest. Cash flow, *before interest*, was calculated as follows:

   $$\text{ATCF-}BI = \text{ATI-}BI + \text{D} \qquad \text{(B3-3a)}$$

   where:
   ATCF-*BI* = after-tax cash flow *before interest*;
   ATI-*BI* = after-tax income *before interest*; and
   D = baseline depreciation.

As a final step in the calculation of after-tax cash flow before interest, EPA eliminated the implied cash flow benefit of any negative taxes, as reported in the facility's income statement and after adjustment for removal of interest. That is, in these calculations, negative taxes increase after-tax income and cash flow, and thus appear to improve the financial performance and value of the facility in terms of cash flow from operations. However, whether *and when* the implied cash flow benefit of negative taxes can be realized depends on the overall profitability and tax circumstances of the total enterprise, including any other facilities owned by the same firm, and the extent of profitability in periods before or after the survey data periods. To be conservative in this analysis, EPA therefore assumed that a facility would not receive the implied cash flow benefit from negative taxes – negative taxes, after adjustment for interest, were set to zero in the baseline analysis. This assumption is consistent with a later step in the post-compliance analysis in which EPA limited the cash flow benefit of tax deductions on compliance outlays not to exceed the amount of taxes paid as reported in the baseline income statement (and adjusted for interest). In theory, the application of this limit could cause some facilities that would otherwise pass the baseline closure analysis, instead to fail the analysis if the reported amount of negative tax, after adjustment for interest, would be sufficient to offset the negative cash flow from operations independent of taxes. In practice, though this limitation did not affect the findings of the baseline closure analysis.

4. *Adjust after-tax cash flow to reflect estimated real change in business performance from the time of survey data collection to the present:* EPA adjusted facility baseline cash flow to reflect the estimated real change (i.e., independent of inflation) in business performance in the manufacturing industries from the time of the facility survey, 1996-1998, to the present. This adjustment is intended to address two potential concerns that could lead to biased findings from the regulatory impact assessment:

   - First, EPA was concerned that facility survey data might have been collected during a period that deviated cyclically from the longer-term trend of business performance for the 316(b) manufacturing industries. Given the knowledge that U.S. business conditions during the latter half of the 1990s were cyclically strong, EPA was particularly concerned that business conditions during the 316(b) survey period (1996-1998) might be abnormally favorable for some of the five Primary Manufacturing Industries. In this case, the business performance and valuation measures, based on survey data, used to assess the burden of regulatory compliance costs might overstate industry's ability to bear these costs and therefore understate the potential impact of the proposed regulation.

   - Second, apart from the issue of short-term deviation from trend caused by a cyclically strong economy, EPA was also aware from its profile analyses that some of the industries might be experiencing a longer-term trend of deteriorating performance. Using sample facility data that don't reflect such possible trends would again potentially overstate industry's ability to bear compliance costs and therefore understate the potential impact of the proposed regulation.

   To calculate the adjustment factor, EPA collected data on after-tax cash flow for public firms in the 316(b) manufacturing industry sectors over a 12-year period and developed adjustment factors by industry and/or key industry segment (details of this analysis are contained in Appendix 4 to Chapter B3). Adjusted after-tax cash flow is calculated as follows:

$$\text{ATCF-}BI_{\text{ADJ}} = \text{ATCF-}BI * \text{Adj} \qquad \text{(B3-3b)}$$

   where:

$\text{ATCF-}BI_{\text{ADJ}}$	=	after-tax cash flow *before interest* adjusted to reflect the real change in business performance; a
ATCF-*BI*	=	after-tax cash flow *before interest*; and
Adj	=	adjustment factor to reflect the real change in business performance.

5. *Calculate <u>free</u> cash flow by adjusting after-tax cash flow from operations for ongoing capital equipment outlays:* The measure of after-tax cash flow from the previous step, cash flow from operations, reflects the cash receipts and outlays from ordinary business operations, but includes no allowance for replacement of the facility's existing capital equipment. To sustain ongoing operations, however, a business must expend cash for capital replacement. Accordingly, to understand the true cash flow of a business and thus provide a conceptually valid cash flow measure for business valuation, it is necessary to reduce cash flow from operations by an allowance for capital replacement. For the calculation of free cash flow, EPA estimated baseline capital outlays from a regression analysis of capital expenditures by public firms in the 316(b)

industry sectors over an 11-year period (details of this analysis and estimation framework are contained in Appendix 5 to Chapter B3). Free cash flow is calculated as follows:

$$FCF = ATCF\text{-}BI_{ADJ} - CAPEX \qquad (B3\text{-}3b)$$

where:
FCF = free cash flow
$ATCF\text{-}BI_{ADJ}$ = after-tax cash flow *before interest* adjusted to reflect the real change in business performance; and
CAPEX = estimated baseline capital outlays.

Or on a more detailed accounting statement basis:

$$FCF = REV - TC - T - \tau I - CAPEX \qquad (B3\text{-}3c)$$

where:
FCF = free cash flow
REV = revenue
TC = total operating costs, *excluding interest, depreciation, and taxes*
T = baseline income tax
τ = estimated combined federal-state tax rate;
I = interest charge from baseline financial statement;
τI = the increase in tax liability resulting from calculating income on a pre-interest basis; and
CAPEX = estimated annual baseline capital outlays.

This calculation of free cash flow is based on a static representation of a facility's business. With the exception of bringing estimated cash flow forward from the time of the survey, 1996-1998, to approximately the present, 2003, the facility impact analysis assumes, in effect, that the facility's business will continue in the future – absent the effects of regulation – exactly as reflected in the baseline financial statements provided in the survey questionnaire

6. *Calculate baseline facility value as the present value of free cash flow over a 10-year analysis horizon:* To calculate baseline business value, EPA discounted free cash flow over a 10-year period at an estimated real (i.e., excluding the effects of inflation), after-tax cost of capital of 7.0%. The use of 10 years as the discounting horizon reflects the expected useful life of capital equipment to be installed for 316(b) regulation compliance. Facility baseline business value is calculated as follows:

$$VALUE = \sum_{t=0}^{9} \frac{FCF}{(1 + CoC)^t} \qquad (B3\text{-}4)$$

where:
VALUE = estimated baseline business value of the facility
FCF = free cash flow
CoC = after-tax cost-of-capital (7.0%); and
t = year index, t = 0-9 (10-year discounting horizon).

In the present value calculation, yearly cash flows accrue at the beginning of the year. As a result, the first year of cash flows is not discounted – i.e., t = 0 for the first year of the analysis – and cash flows in the tenth and final year of the analysis period are discounted over a 9-year period – i.e., t = 9 in the final year of the analysis.

As explained above, EPA considered a facility to be a baseline closure if its estimated business value was negative before incurring regulatory compliance costs. Baseline closures were neither tested for adverse impact in the post-compliance impact analysis nor were their compliance costs included in the tally of total costs of 316(b) regulatory compliance.

❖ ***Calculation of Post-Compliance Free Cash Flow and Performance of Post-Compliance Closure Test***
For the post-compliance closure analysis, EPA recalculated annual free cash flow, accounting for changes in annual expenses and taxes that are estimated to result from compliance-related outlays. EPA combined the post-compliance free cash flow value and the estimated compliance capital outlay in the present value framework to calculate business value on a post-compliance basis.

Calculation of post-compliance free cash flow and performance of the post-compliance closure test involved the following steps:

1. *Adjust baseline annual free cash flow to reflect compliance expense effects:* Compliance-related effects on annual free cash flow include: annually recurring operating and maintenance costs; the annual equivalent of permitting and repermitting costs, which recur on other than an annual basis over the life of the analysis; the annual equivalent of the income loss from installation downtime (see Appendix 2); and related changes in taxes[4]. The change in taxes includes: (1) the tax effect of these annually recurring and annualized expenses and (2) the tax effect from depreciation of initial compliance outlays. For calculating the tax effect of depreciation, EPA assumed that compliance capital outlays would be depreciated for tax purposes on a 10-year straight-line schedule. Post-compliance free cash flow was calculated as follows:

$$FCF_{PC} = FCF_{BL} - \Delta TC - \tau(- \Delta TC - \Delta D) \qquad \text{(B3-5)}$$

   where:
   FCF_{PC} = post-compliance free cash flow;
   FCF_{BL} = baseline free cash flow, as calculated above;
   ΔTC = change in total facility annual costs (excluding interest, depreciation and taxes), calculated as the cost of operating and maintaining compliance equivalent plus the annual equivalent of certain non-annual costs, as described above;
   τ = marginal tax rate for calculating compliance-related tax effects (combined federal-state tax rate); and
   ΔD = change in depreciation expense, calculated as compliance capital outlay (CC) divided by 10.

2. *Limit tax adjustment to not exceed taxes as reported in baseline financial statement:* The tax effect of compliance outlays is to reduce tax liability. As a result, in the free cash flow calculation, the tax adjustment generally increases cash flow and business value and, all else equal, reduces the likelihood that a facility will fail the post-compliance closure test. However, the extent to which a facility would realize this contribution to cash flow depends on its tax circumstances. In particular, some businesses may not be paying sufficient taxes in the baseline to take full benefit of the implied tax reduction *at the facility level* – unless the unused tax loss can be transferred to other, profitable business units in the firm, these businesses would not be able to use fully the implied tax reduction on a current basis. Also, the marginal tax rate for businesses with relatively lower pre-tax income may be less than the combined Federal/State tax rate used in the analysis.

[4] For the facility cash flow analysis, EPA treated the income loss from installation downtime on an annual equivalent basis even though this financial event occurs only once, and at the beginning of the assumed analysis period. EPA treated the installation downtime on an annualized basis for two reasons. First, the installation downtime is assumed to have a useful "financial life" of 30 years to reflect the total potential business life of the facility (note that reinstallation of the basic capital equipment, which is assumed to recur on a 10-year interval, does not require a new round of downtime). Since compliance capital equipment is assumed to have a 10-year useful life and the discounted cash flow analysis is accordingly structured as a 10-year analysis, including the income loss from installation downtime (which is assumed to have a 30-year useful life) as a one-time up-front cost would overstate its impact in the discounted cash flow calculation. Second, calculation of the downtime cost on an annual basis allows the tax effect from the one-time income loss to be summed with other annual tax effects for applying the limit to tax offsets, as explained in the next step of the analysis.

While businesses may be able to carry forward tax losses to reduce taxes in later years, EPA recognizes that the implied cash flow benefit from tax reduction may not be fully realized, particularly in circumstances involving single-facility firms. To be conservative in its analysis, EPA therefore limited the amount of tax reduction from compliance outlays to be no greater than the amount of tax paid by facilities as reported in the baseline financial statement. The analysis effectively assumes that facilities will not be able to offset an implicit negative tax liability against positive tax liability elsewhere in the owning firm's operations or to carry forward (or back) the negative income and its implicit negative tax liability to other positive income/positive tax liability operating periods. On average, this approach overstates impacts on facilities, because some businesses may be able to benefit from tax reductions that exceed facility baseline taxes, especially if the facility is owned by a multiple-site firm. Accordingly, EPA constrained the tax effect term in the free cash flow calculation, $[-\tau(- \Delta TC - \Delta D)]$ as specified above, to be no greater than baseline financial statement tax liability, T.

3. *Calculate post-compliance facility value, including post-compliance free cash flow and the compliance capital outlay:* As in the baseline analysis, EPA calculated post-compliance facility value as the present value of free cash flow and accounting for the compliance capital outlay as an undiscounted cash outlay in the first analysis period. Facility post-compliance business value was calculated as follows:

$$VALUE_{PC} = \sum_{t=0}^{9} \frac{FCF_{PC}}{(1 + CoC)^t} - CC \qquad \text{(B3-6)}$$

where:

$VALUE_{PC}$	=	estimated post-compliance business value of the facility
FCF_{PC}	=	estimated post-compliance free cash flow
CoC	=	after-tax cost-of-capital (7.0%);
t	=	year index, t = 0-9 (10-year discounting horizon); and
CC	=	compliance capital outlay.

EPA considered a facility to be a post-compliance closure if its estimated business value was positive in the baseline but became negative after adjusting for compliance-related cost, revenue and tax effects. In addition to tallying closure impacts in terms of the number of estimated facility closures, EPA also measured the significance of closures in terms of losses in employment and output. Employment losses equal the number of employees reported by closure facilities in survey responses; output losses equal total revenue reported for regulatory closure facilities. EPA estimated national results by multiplying facility results by facility sample weights.[5]

b. Test of Moderate Impacts

EPA also conducted an analysis of financial stress short of closure to identify the regulation's moderate impacts. Facilities incurring moderate impacts are not projected to close due to the proposed Section 316(b) regulation. The regulation, however, might reduce their financial performance to the point where they incur greater difficulty and higher costs in obtaining financing for future investments.

The analysis of moderate impacts examined two financial measures:

Pre-Tax Return on Assets (PTRA): ratio of pre-tax operating income – earnings before interest and taxes (EBIT) – to assets. This ratio measures the operating performance and profitability of a business' assets independent of financial structure and tax circumstances. PTRA is a comprehensive measure of a firm's economic and financial performance. If a firm cannot sustain a competitive PTRA on a post-compliance basis, it will likely face difficulty financing its investments, including the outlay for compliance equipment.

[5] For the analysis of options presented in this chapter, none of these impact measures (e.g., employment loss, output loss) were in fact relevant because none of the three primary presentation options resulted in regulatory closures.

Interest Coverage Ratio (ICR): ratio of pre-tax operating cash flow – earnings before interest, taxes, and depreciation (EBITDA) – to interest expense. This ratio measures the facility's ability to service its debt on the basis of current, ongoing financial performance and to borrow for capital investments. Investors and creditors will be concerned about a firm whose operating cash flow does not comfortably exceed its contractual obligations. The greater the ICR, the greater the firm's ability to meet interest payments, and, generally speaking, the greater the firm's credit-carrying ability. ICR also provides a measure of the amount of cash flow available for equity after interest payments.

Creditors and equity investors review the above two measures as criteria to determine whether and under what terms they will finance a business. PTRA and ICR also provide insight into a firm's ability to generate funds for compliance investments from internally-generated equity, i.e., from after-tax cash flow. The measures are defined as follows:

Pre-Tax Return on Assets

$$PTRA = \frac{EBIT}{TA} \qquad \text{(B3-7)}$$

where:

PTRA	=	pre-tax return on assets,
EBIT	=	pre-tax operating income, or *earnings before interest and taxes*, and
TA	=	total assets.

Or, stated in terms of 316(b) income statement accounts,

$$PTRA = \frac{REV - (TC + D)}{TA} \qquad \text{(B3-8)}$$

where:

PTRA	=	pre-tax return on assets;
REV	=	revenue;
TC	=	total operating costs (excluding interest, taxes, and depreciation/amortization);
D	=	depreciation; and
TA	=	total assets.

Interest Coverage Ratio

$$ICR = \frac{EBITDA}{I} \qquad \text{(B3-9)}$$

where:

ICR	=	interest coverage ratio;
EBITDA	=	pre-tax operating cash flow, or *earnings before interest, taxes, and depreciation (and amortization)* and
I	=	interest expense.

Or, stated in terms of 316(b) income statement accounts,

$$ICR = \frac{REV - TC}{I} \tag{B3-10}$$

where:

- ICR = interest coverage ratio;
- REV = revenue;
- TC = total operating costs (excluding interest, taxes, and depreciation/amortization); and
- I = interest expenses.

Including the effects of 316(b) compliance costs, post-compliance PTRA and ICR are:

$$PTRA_{pc} = \frac{[REV - (TC + \Delta TC + D + \Delta D)]}{(TA + CC)} \tag{B3-11}$$

$$ICR_{pc} = \frac{[REV - (TC + \Delta TC)]}{(I + \Delta I)} \tag{B3-12}$$

where:

- $PTRA_{pc}$ = pre-tax return on assets, post-compliance;
- ICR_{pc} = interest coverage ratio, post-compliance;
- ΔTC = change in total facility operating costs (excluding interest, depreciation and taxes), calculated as operating and maintenance costs of compliance;
- ΔD = change in depreciation expense, calculated as compliance capital outlay (CC) divided by 10;
- CC = compliance capital outlay (assuming all of the outlay would be capitalized and reported as an addition to assets on the balance sheet); and
- ΔI = incremental interest expense from financing of compliance capital outlay. As a simplifying, conservative assumption, incremental interest expense is calculated assuming that the compliance capital outlay is fully debt financed at the overall real cost-of-capital of 7.0%. The annual incremental interest value is calculated as the annualized value of interest payments over 10 years, assuming a constant annual payment of principal and interest.

In calculating the baseline values of the PTRA and ICR measures, EPA applied the same cash flow adjustments as described above for the facility closure analysis, to the numerators of the PTRA and ICR measures. In the same way as described for the facility closure analysis, these adjustments are intended to capture the change in the financial performance of firms in the Primary Manufacturing Industries between the time of the 316(b) Phase III survey and 2003 (see Appendix 4 to Chapter B3).

For evaluating 316(b) manufacturing facilities according to the moderate impact measures, EPA compared baseline and post-compliance PTRA and ICR to 316(b) industry-specific thresholds that were developed from data compiled by Risk Management Association, Inc. (RMA). RMA compiles and reports financial statement information by industry as provided by member commercial lending institutions. The threshold values represent the 25th percentile values of PTRA and ICR for statements received by RMA for the eight years from 1994 to 2001 within relevant industries. EPA developed 316(b) industry-level values by weighting and summing the

RMA industry values according to the definition of 316(b) industries[6]. Thresholds by sector ranged from 1.8% to 2.9% for PTRA and from 2.0 to 2.4 for ICR. Because the financial statements received by RMA are for businesses applying for credit from member institutions, the data don't represent a random sample. In particular, the RMA data likely exclude representation from the financially weakest businesses, which are unlikely to seek financing from RMA member lending institutions. As a result, EPA views the threshold values as being relatively conservative and likely to overstate the occurrence of moderate impacts.

Both measures are important to financial success and firms' ability to attract capital. Facilities failing at least one of the moderate impact measures in the baseline were deemed to be already experiencing moderate financial weakness and were not tested for additional financial impact in the moderate impact analysis. Facilities that passed both moderate impact tests in the baseline but failed one or both threshold comparisons, post-compliance, were considered to incur moderate financial impacts, short of closure, as a result of the proposed Section 316(b) regulation.

c. Firm Level Impacts

The analysis of impact on firms builds on the facility impact analysis to assess whether firms that own multiple facilities are likely to incur more significant impacts than indicated by the facility impact analysis. For the assessment of firm-level effects, EPA calculated annualized after-tax compliance costs as a percentage of firm revenue and reports the estimated number and percentage of affected firms incurring compliance costs in 3 cost-to-revenue ranges: less than 1.0%; at least 1.0% but less than 3.0%; and 3.0% or greater.

EPA's sample-based facility analysis supports specific estimates of (1) the number of facilities expected to be subject to the regulation and (2) the total compliance costs expected to be incurred in these facilities. However, the sample-based analysis does not support specific estimates of the number of firms that own manufacturing facilities. In addition and as a corollary, the sample-based analysis does not support specific estimates of the number of regulated facilities that may be owned by a single firm, or of the total of compliance costs across regulated facilities that may be owned by a single firm.

For the firm level analysis, EPA therefore considered two cases based on the sample weights developed from the facility survey. These cases provide approximate upper and lower bound estimates on: (1) the number of firms incurring compliance costs and (2) the costs incurred by any firm owning a regulated facility. The cases are as follows:

Case 1: Upper bound estimate of number of firms owning facilities that face requirements under the regulation; lower bound estimate of total compliance costs that a firm may incur.

For this case, EPA assumed (1) that a firm owns only the regulated sample facility(ies) that it is known to own from the sample analysis and (2) that this pattern of ownership, observed for sampled facilities and their owning firms, extends over the facility population represented by the sample facilities. This case minimizes the possibility of multi-facility ownership by a single firm and thus maximizes the count of affected firms, but also minimizes the potential cost burden to any single firm.

For each firm that owns one sample facility, no firm is assumed to own more than one regulated facility, and the analysis is straightforward: the firm owns one regulated facility and incurs compliance costs only for that facility. This configuration is assumed to exist as many as times as the facility's sample weight. However, EPA found that 28% of the firms identified as owning a sample facility, own more than one sample facility. Where the multiple facilities owned by the same firm have the same sample weight, the analysis is also straightforward: the firm is assumed to own and incur the compliance costs of the identified sample facilities, and the configuration is assumed to exist as many times as many times as the uniform sample weight of the multiple facilities.

6 See Appendix 6 to Chapter B3 for details of moderate impact threshold development and sector-specific threshold values.

In some instances, however, the sample facilities that are owned by the same firm have different sample weights. In these cases, which required a more complex analysis, EPA accounted for the ownership of multiple sample facilities by a single firm, but restricted the count of the multiple facilities and their configuration of ownership for the firm-level cost analysis based on the sample weights of the individual sample facilities. Specifically, the *firm* is assumed to exist on a sample-weighted basis as many times as the *highest* of the sample weights among the sample facilities known to be owned by the firm. However, sample facilities with a smaller sample weight, *and their compliance costs*, can be included in the total instances of ownership by the firm for only as many times as their sample weights. Otherwise, the total facility count implied in the firm analysis would exceed the sample-based estimated total of facilities; correspondingly, the total of compliance costs accounted for in the firm level analysis would exceed the sample-based estimated total of facility compliance costs. For implementation, this concept means that *all* of the sample facilities known to be owned by the same firm, *and their compliance costs*, can be included in the ownership configuration for only as many sample weighted instances as the smallest sample weight among the multiple facilities owned by the firm. Once the sample weight of the smallest sample weight facility is "used up," a new multiple facility ownership is configured including only the costs for those facilities with weights greater than the weight of the smallest sample weight facility. This configuration is assumed to exist for as many sample weighted instances as the difference between the lowest sample weight and the next higher sample weight among the facilities owned by the firm. This process is repeated – with successive removal of the new lowest sample weight facility, and its compliance cost– as many times as necessary until only the highest sample weight facility remains in the ownership configuration.

The survey asked respondents to provide firm-level revenue for the parent firm. For single-facility firms, firm revenue and compliance costs are identical to those for the facility. For multi-facility firms, EPA grouped together all facilities with a common parent firm from the surveys. For each firm in the analysis, firm-level compliance cost is:

$$CC_{firm} = \sum_{i} CC_i \qquad \text{(B3-13)}$$

where:

CC_{firm} = firm-level compliance cost
CC_i = compliance cost for the surveyed facility i, known to be owned by the *firm*

Case 2: Lower bound estimate of number of firms owning facilities that face requirements under the regulation; upper bound estimate of total compliance costs that a firm may incur.

For this case, EPA inverted the prior assumption and assumed that any firm owning a regulated sample facility(ies), owns the known sample facility(ies) and all of the sample weight associated with the sample facility(ies). This case minimizes the count of affected firms, while tending to maximize the potential cost burden to any single firm.

For this case, EPA grouped together all facilities with a common parent firm from the surveys and sample weighted the facility compliance costs. EPA calculated the firm-level compliance cost as:

$$CC_{firm} = \sum_{i} CC_i \times \mathbf{W}_i \qquad \text{(B3-13)}$$

where:

CC_{firm} = firm-level compliance cost
CC_i = compliance cost for surveyed facility i owned by the firm
W_i = sample weight for surveyed facility i owned by the firm

As stated above, for the analysis of firm-level impacts, EPA calculated annualized after-tax compliance costs as a percentage of firm revenue. EPA judged that firms with annualized after-tax compliance cost of less than 1.0% of revenue would not be materially affected by the regulation. EPA identified firms as subject to potentially more serious impacts if annualized compliance cost exceeded 3.0% of revenue.

B3-3 RESULTS

This section presents the results of the facility impact analysis. The first section presents the results of the baseline closure analysis. The subsequent sections report the impact analysis results for the three proposed options. Section B3-3.2 presents the number of facilities with regulatory requirements under the different options. Section B3-3.3 discusses post-compliance closures. Section B3-3.4 presents the number of facilities with moderate impacts by industry. Section B3-3.5 summarizes total annualized compliance costs on an after-tax basis by option. Section B3-3.6 summarizes the estimated impacts by option, including facility impacts and total annualized compliance costs on both a pre-tax and after-tax basis. Section B3-3.7 presents the results of the firm-level analysis for the two analytic cases described above.

B3-3.1 Baseline Closures

Table B3-1 reports estimated baseline closures for facilities in the Primary Manufacturing Industries and the additional known facilities in Other Industries. EPA determined that 76 facilities (or 14%) of the estimated 532 regulated facilities in the five Primary Manufacturing Industries have a negative business value before incurring regulatory compliance costs. The highest percentages of baseline closures occur in the Steel industry sector (43%) and Aluminum industry sector (33%). An additional four facilities (or 18%) of the 22 known facilities in Other Industries are baseline closures. These facilities are projected to close in the baseline and are not considered in the analysis of impacts attributable to the regulation.

Appendix 7 to Chapter B3 provides information on typical establishment closure rates in the 316(b) industries. EPA compared the percentage of facilities assessed as baseline closures to typical establishment closure rates in the five Primary Manufacturing Industries, as reported in Statistics of U.S. Businesses (SUSB). SUSB data indicate that between 1.4% and 12.5% of all facilities in these industries, close annually. The percentage of facilities assessed as baseline closures in the Steel and Aluminum industries is higher than the typical closure rates in the industries. However, EPA based its analysis on survey data provided by the facilities and believes these data and analysis provide an accurate representation of the financial condition of the facilities that would subject to the Phase III regulation.

Table B3-1: Summary of Baseline Closures by Sector

Sector	Total Number of Facilities	Number of Baseline Closures	Percentage Closing in Baseline	Number Operating in Baseline
Paper	230	32	13.9%	198
Chemicals	178	4	2.2%	173
Petroleum	36	5	13.9%	30
Steel	68	29	42.6%	40
Aluminum	21	7	33.3%	14
Total Facilities in Primary Manufacturing Industries	**532**	**76**	**14.3%**	**456**
Additional known facilities in Other Industries	22	4	18.2%	18

Source: U.S. EPA analysis, 2004.

B3-3.2 Number of Facilities with Regulatory Requirements

Of the three options presented here, the 50 MGD Option for All Waterbodies, would the largest number of facilities, 133 facilities, or 127 facilities in the Primary Manufacturing Industries and 6 known facilities in Other Industries to national categorical requirements (see Table B3-2). The 200 MGD for All Waterbodies, would subject a smaller set of Manufacturers to national requirements: 24 facilities, or 22 facilities in the Primary Manufacturing Industries and 2 of the known facilities in Other Industries. The 100 MGD for Certain Waterbodies Option, would subject the smallest number of facilities to national requirements: 20 facilities, or 18 facilities in the Primary Manufacturing Industries and 2 known facilities in the Other Industries.

Table B3-2: Number of Facilities with Regulatory Requirements by Sector and Option

Sector	Total Operating in Baseline	Number of Facilities with Regulatory Requirements					
		50 MGD All		200 MGD All		100 MGD CWB	
		Number	Percentage	Number	Percentage	Number	Percentage
Paper	198	37	18.7%	3	1.5%	0	0.0%
Chemicals	173	52	30.1%	5	2.9%	7	4.0%
Petroleum	30	13	43.3%	3	10.0%	5	16.7%
Steel	40	22	55.0%	9	22.5%	6	15.0%
Aluminum	14	5	35.7%	1	7.1%	0	0.0%
Total Facilities in Primary Manufacturing Industries	**456**	**127**	**27.9%**	**22**	**4.8%**	**18**	**3.9%**
Additional known facilities in Other Industries	*18*	*6*	*33.3%*	*2*	*11.1%*	*2*	*100.0%*

Source: U.S. EPA analysis, 2004.

B3-3.3 Post-Compliance Impacts

Of the 474 facilities potentially subject to regulation after baseline closures, EPA estimated that no facilities would close or incur employment losses as a result of any of the three proposed options.

EPA also found that none of the Manufacturers would incur a moderate impact (i.e, financial stress short of closure) under any of the three proposed options.

B3-3.4 Compliance Costs

Table B3-3 reports the estimated total after-tax compliance cost to facilities in the Primary Manufacturing Industries and the known facilities in Other Industries by sector and regulatory option. The reported costs exclude costs in baseline closures. The total annualized, after-tax compliance cost reported in Table B3-3 represents the cost actually incurred by complying firms, assuming no recovery of costs from customers through increased prices and taking into account the reductions in tax liability resulting from incurrence of compliance outlays. The after-tax analysis uses a combined Federal/State tax rate, and accounts for facilities' baseline tax circumstances. Specifically, tax offsets to compliance costs are limited to not exceed facility-level tax payments as reported in facility questionnaire responses. The total annualized, after-tax compliance cost reported here is the sum of annualized, after-tax costs by facility at the year of compliance. This cost calculation differs in concept from the calculation of compliance costs as included in the calculation of the total social costs of the regulation. For the social cost calculation, which is presented in *Chapter E1: Summary of Social Costs*, the year-by-year stream of total pre-tax compliance costs for all facilities is discounted to the assumed year of promulgation of the 316(b) final regulation for Phase III facilities – i.e., beginning of year 2007 – and then annualized. Two social discount rate values, 3% and 7%, are used in the social cost analysis.

Of the three options described here, the 50 MGD Option for All Waterbodies, has the highest total after-tax compliance cost, $38.0 million: $32.8 million for facilities in the Primary Manufacturing Industries, and $5.2 million for known facilities in Other Industries. The 100 MGD for Certain Waterbodies has the next higher total after-tax compliance cost, $16.4 million: $15.8 million for facilities in the Primary Manufacturing Industries, and $0.6 million for known facilities in Other Industries. The 200 MGD Option for All Waterbodies, would have the lowest cost, $14.5 million: $13.7 million for facilities in the Primary Manufacturing Industries, and $0.7 million for known facilities in Other Industries.

Table B3-3: Total Annualized Facility Compliance Cost[a] by Sector and Regulatory Option (millions, 2003$)

Sector	After-Tax Costs		
	50 MGD All	200 MGD All	100 MGD CWB
Paper	$5.0	$2.1	$0.0
Chemicals	$15.9	$3.6	$9.0
Petroleum	$4.7	$3.0	$3.2
Steel	$6.3	$5.0	$3.6
Aluminum	$0.8	$0.0	$0.0
Total Facilities in Primary Manufacturing Industries	**$32.8**	**$13.7**	**$15.8**
Additional known facilities in Other Industries	*$5.2*	*$0.7*	*$0.6*

[a] This table reflects the cost incurred by complying businesses and does not represent the cost to society from regulatory compliance. *Chapter E1: Summary of Social Costs* discusses the social cost of the proposed regulation and the other options. The values in this table exclude baseline closures.

Source: U.S. EPA analysis, 2004.

B3-3.5 Summary of Facility Impacts

Table B3-4 summarizes the estimated impacts of the three proposed regulatory options for Manufacturers, as reported in the preceding sections.

Table B3-4: Regulatory Impacts for All Facilities by Option, National Estimates

	50 MGD All	200 MGD All	100 MGD CWB
Primary Manufacturing Industries			
Number of Facilities Operating in Baseline	456	456	456
Number of Facilities with Regulatory Requirements	127	22	18
Percentage of Facilities with Regulatory Requirements	27.9%	4.8%	3.9%
Number of Closures (Severe Impacts)	0	0	0
Percentage of Facilities with Regulatory Requirements Predicted to Close	0.0%	0.0%	0.0%
Number of Facilities with Moderate Impacts	0	0	0
Percentage of Facilities with Regulatory Requirements with Moderate Impacts	0.0%	0.0%	0.0%
Annualized Compliance Costs (after tax, million $2003)	$32.8	$13.7	$15.8
Additional Known Facilities in Other Industries			
Number of Facilities Operating in Baseline	18	18	18
Number of Facilities with Regulatory Requirements	6	2	2
Percentage of Facilities with Regulatory Requirements	33.3%	11.1%	11.1%
Number of Closures (Severe Impacts)	0	0	0
Percentage of Facilities with Regulatory Requirements Predicted to Close	0.0%	0.0%	0.0%
Number of Facilities with Moderate Impacts	0	0	0
Percentage with Moderate Impacts	0.0%	0.0%	0.0%
Annualized Compliance Costs (after tax, million $2003)	$5.2	$0.7	$0.6

Source: U.S. EPA analysis, 2004.

B3-3.6 Firm Impacts

As previously discussed, EPA's analysis of firm-level impacts considered two analytic cases:

- Case 1: Approximate upper bound estimate of number of firms owning facilities that face requirements under the regulation; approximate lower bound estimate of total compliance costs that a firm may incur, and

- Case 2: Lower bound estimate of number of firms owning facilities that face requirements under the regulation; approximate upper bound estimate of total compliance costs that a firm may incur.

Based on these two analytic cases, EPA estimated the number of firms owning regulated facilities in the Primary Manufacturing Industries to range from 100 (Case 2 estimate) to 313 (Case 1 estimate), depending on the assumed ownership cases outlined above. An additional 14 firms are known to own facilities in Other Industries. EPA included the additional known facilities in Other Industries in the firm impact analyses but since these facilities have no sample weight (i.e., they are not modeled to represent facilities other than themselves), the upper and lower bound estimates were not applicable to them.

Under both Case 1 and Case 2, no firms are estimated to incur total compliance costs equal to or exceeding 1.0% of annual revenue under any of the three proposed options (See Table B3-5, below).

Table B3-5: Firm-Level After-Tax Annual Compliance Costs as a Percentage of Annual Revenue

Number of Firms in the Analysis	Number and Percentage with After Tax Annual Compliance Costs/Annual Revenue Equal to:								
	Total	No Costs		Less than 1%		1-3%		At Least 3%	
		Number	%	Number	%	Number	%	Number	%
Primary Manufacturing Industries[a]									
Case 1: Upper bound estimate of number of firms owning facilities that face requirements under the regulation; lower bound estimate of total compliance costs that a firm may incur									
50 MGD All	313	208	66%	105	34%	0	0%	0	0%
200 MGD All	313	292	93%	21	7%	0	0%	0	0%
100 MGD CWB	313	293	94%	21	7%	0	0%	0	0%
Case 2: Lower bound estimate of number of firms owning facilities that face requirements under the regulation; upper bound estimate of total compliance costs that a firm may incur									
50 MGD All	100	54	54%	46	46%	0	0%	0	0%
200 MGD All	100	86	86%	14	14%	0	0%	0	0%
100 MGD CWB	100	88	88%	12	12%	0	0%	0	0%
Other Industries									
50 MGD All	14	10	71%	4	29%	0	0%	0	0%
200 MGD All	14	13	93%	1	7%	0	0%	0	0%
100 MGD CWB	14	13	93%	1	7%	0	0%	0	0%

[a] Two known facilities in Other Industries are owned by firms that own facilities in the Primary Manufacturing Industries and are included in this category.

Source: U.S. EPA analysis, 2004.

GLOSSARY

after-tax cash flow (ATCF): The cash generated from business operations, after-tax, that is available to providers of capital – equity and debt – or for reinvestment in the business.

baseline closures: Facilities showing inadequate financial performance in the baseline, that is, in the absence of the regulation. EPA's analysis assumes these closures would have occurred with or without the regulation.

Construction Cost Index (CCI): Measures the cost of a hypothetical package of general construction goods and services compared a base year. The CCI can be used where labor costs are a high proportion of total costs. The CCI uses 200 hours of common labor, multiplied by the 20-city average rate for wages and fringe benefits. (http://www.enr.com/cost/costfaq.asp)

cost of capital: Costs incurred for a firm to obtain financing from all capital sources including, in particular, equity and debt.

cost pass-through: Calculates the percentage of compliance costs that EPA expects firms subject to regulation to recover from customers through increased revenue.

facility: A contiguous set of buildings or machinery on a piece of land under common ownership.

free cash flow: Cash flow generated by the company that is available to all providers of the company's capital, both creditors and shareholders.

Gross Domestic Product (GDP) Implicit Price Deflator: The GDP Deflator is a quarterly series that measures the implicit change in prices, over time, of the bundle of goods and services comprising gross domestic product.

interest coverage ratio (ICR): Ratio of cash operating income to interest expenses. This ratio measures the facility's ability to service its debt and borrow for capital investments.

liquidation value: Net amount that could be realized by selling the assets of a firm after paying debt.

moderate impacts: Adverse changes in a facility's financial position that weaken financial performance and may increase cost of financing but are not threatening to short-term viability.

operating and maintenance: Costs estimated to result from operating and maintaining pollution controls adopted to comply with effluent guidelines. Operating costs include the costs of monitoring.

pre-tax return on assets (PTRA): Ratio of cash operating income to assets. This ratio measures facility profitability.

regulatory closure: A facility that is predicted to close because it can not afford the costs of complying with the regulation.

severe impacts: Facility closures and the associated losses in jobs, earnings, and output at facilities that close due to the regulation.

ABBREVIATIONS

ATCF: after-tax cash flow
CCI: construction cost index
ICR: interest coverage ratio
PTRA: pre-tax return on assets

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Appendices to Chapter B3

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Appendix 1 to Chapter B3: Summary of Results for Alternative Options

INTRODUCTION

APPENDIX CONTENTS

This appendix presents results for 5 additional regulatory options considered by EPA. For these options, facility counts and other results include only those Phase III Manufacturers that are (1) non-baseline closures and (2) subject to national categorical requirements under the option. See the main body of this chapter for a description of data sources and methodologies used in these analyses. In the following tables, the results for these additional options are presented in order of increasing estimated total annualized cost of compliance.

B3A1-1 NUMBER OF FACILITIES WITH REGULATORY REQUIREMENTS

Table B3A1.1: Number of Facilities with Regulatory Requirements by Sector and Option

Sector	Total Operating in Baseline	Number of Facilities with Regulatory Requirements				
		Option 3	Option 4	Option 2	Option 1	Option 6
Paper	198	117	46	117	117	198
Chemicals	173	116	75	116	116	173
Petroleum	30	18	13	18	18	30
Steel	40	33	23	33	33	40
Aluminum	14	8	5	8	8	14
Total Facilities in Primary Manufacturing Industries	**456**	**292**	**162**	**292**	**292**	**456**
Additional known facilities in Other Industries	*18*	*9*	*7*	*9*	*9*	*18*

Source: U.S. EPA analysis, 2004.

B3A1-2 POST-COMPLIANCE CLOSURES

For a description of this analysis, see section B3-2.3 above.

Table B3A1.2: Number of Facilities Estimated as Post-Compliance Closures by Sector and Option

Sector	Total Operating in Baseline	Number of Post-Compliance Closures				
		Option 3	Option 4	Option 2	Option 1	Option 6
Paper	198	0	0	0	0	0
Chemicals	173	0	0	0	0	0
Petroleum	30	0	0	0	0	0
Steel	40	0	0	0	0	0
Aluminum	14	0	0	0	0	0
Total Facilities in Primary Manufacturing Industries	**456**	**0**	**0**	**0**	**0**	**0**
Additional known facilities in Other Industries	*18*	*0*	*0*	*0*	*0*	*0*

Source: U.S. EPA analysis, 2004.

B3A1-3 MODERATE IMPACTS

For a description of this analysis, see section B3-2.3 above.

Table B3A1.3: Number of Facilities Estimated as Moderate Impacts by Sector and Option

Sector	Total Operating in Baseline	Number of Moderate Impacts				
		Option 3	Option 4	Option 2	Option 1	Option 6
Paper	198	0	0	0	0	0
Chemicals	173	0	0	0	0	0
Petroleum	30	0	0	0	0	0
Steel	40	0	0	0	0	0
Aluminum	14	0	0	0	0	0
Total Facilities in Primary Manufacturing Industries	**456**	**0**	**0**	**0**	**0**	**0**
Additional known facilities in Other Industries	*18*	*0*	*0*	*0*	*0*	*0*

Source: U.S. EPA analysis, 2004.

B3A1-4 After-Tax Compliance Costs

For a description of this analysis, see section B3-2.3 above.

Table B3A1.4: Total Annualized Facility[a] After-Tax Compliance Cost by Sector and Option (millions, 2003$)

Sector	Option 3	Option 4	Option 2	Option 1	Option 6
Paper	$8.5	$7.2	$9.6	$11.3	$22.9
Chemicals	$28.3	$35.1	$35.9	$35.9	$42.0
Petroleum	$4.7	$4.7	$4.7	$4.7	$4.8
Steel	$7.2	$7.4	$8.1	$8.1	$8.1
Aluminum	$0.8	$0.8	$0.8	$0.8	$0.9
Total Facilities in Primary Manufacturing Industries	**$49.5**	**$55.3**	**$59.1**	**$60.8**	**$78.8**
Additional known facilities in Other Industries	*$5.6*	*$5.4*	*$5.6*	*$5.6*	*$5.8*

[a] This table reflects the cost incurred by complying businesses and does not represent the cost to society from regulatory compliance. *Chapter E1: Summary of Social Costs* discusses the social cost of the proposed rule and the other options. The estimates in this table exclude baseline and include regulatory closures, and are after-tax.

Source: U.S. EPA analysis, 2004.

B3A1-5 OVERVIEW OF IMPACTS

For a description of this analysis, see section B3-2.3 above.

Table B3A1.5: Regulatory Impacts for All Facilities by Option, National Estimates

	Option 3	Option 4	Option 2	Option 1	Option 6
Primary Manufacturing Industries					
Number of Facilities Operating in Baseline	456	456	456	456	456
Number of Facilities with Regulatory Requirements	292	162	292	292	456
Percentage of Facilities with Regulatory Requirements	64.0%	35.5%	64.0%	64.0%	100.0%
Number of Closures (Severe Impacts)	0	0	0	0	0
Percentage of Facilities with Regulatory Requirements Predicted to Close	0.0%	0.0%	0.0%	0.0%	0.0%
Number of Facilities with Moderate Impacts	0	0	0	0	0
Percentage of Facilities with Regulatory Requirements with Moderate Impacts	0.0%	0.0%	0.0%	0.0%	0.0%
Annualized Compliance Costs (after tax, million $2003)	$49.5	$55.3	$59.1	$60.8	$78.8
Additional Known Facilities in Other Industries					
Number of Facilities Operating in Baseline	18	18	18	18	18
Number of Facilities with Regulatory Requirements	9	7	9	9	18
Percentage of Facilities with Regulatory Requirements	50.0%	38.9%	50.0%	50.0%	100.0%
Number of Closures (Severe Impacts)	0	0	0	0	0
Percentage of Facilities with Regulatory Requirements Predicted to Close	0.0%	0.0%	0.0%	0.0%	0.0%
Number of Facilities with Moderate Impacts	0	0	0	0	0
Percentage of Facilities with Regulatory Requirements with Moderate Impacts	0.0%	0.0%	0.0%	0.0%	0.0%
Annualized Compliance Costs (after tax, million $2003)	$5.6	$5.4	$5.6	$5.6	$5.8

Source: U.S. EPA analysis, 2004.

B3A1-6 Firm Impacts

For a description of this analysis, see section B3-2.3 above.

Table B3A1.6: Firm-level After-Tax Annual Compliance Costs as a Percentage of Annual Revenue

Number of Firms in the Analysis	Number and Percentage with After Tax Annual Compliance Costs/Annual Revenue Equal to:								
	Total	No Costs		Less than 1%		1-3%		At Least 3%	
		Number	%	Number	%	Number	%	Number	%
Primary Manufacturing Industries[a]									
Case 1: Upper bound estimate of number of firms owning facilities that face requirements under the regulation; lower bound estimate of total compliance costs that a firm may incur									
Option 3	313	114	36%	199	64%	0	0%	0	0%
Option 4	313	180	58%	133	42%	0	0%	0	0%
Option 2	313	114	36%	199	64%	0	0%	0	0%
Option 1	313	114	36%	199	64%	0	0%	0	0%
Option 6	313	0	0%	313	100%	0	0%	0	0%
Case 2: Lower bound estimate of number of firms owning facilities that face requirements under the regulation									
Option 3	100	31	31%	69	69%	0	0%	0	0%
Option 4	100	48	48%	52	52%	0	0%	0	0%
Option 2	100	31	31%	69	69%	0	0%	0	0%
Option 1	100	31	31%	69	69%	0	0%	0	0%
Option 6	100	0	0%	99	99%	1	1%	0	0%
Other Industries									
Option 3	14	8	57%	6	43%	0	0%	0	0%
Option 4	14	9	64%	5	36%	0	0%	0	0%
Option 2	14	8	57%	6	43%	0	0%	0	0%
Option 1	14	8	57%	6	43%	0	0%	0	0%
Option 6	14	0	0%	14	100%	0	0%	0	0%

[a] Two known facilities in Other Industries are owned by firms that own facilities in the Primary Manufacturing Industries and are included in this category.

Source: U.S. EPA analysis, 2004.

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Appendix 2 to Chapter B3: Calculation of Installation Downtime Cost

APPENDIX CONTENTS

INTRODUCTION

Depending on the engineering design of a facility's cooling water intake system, installation of some of the compliance technologies considered for the proposed regulation could require a one-time, temporary shut-down of the facility's cooling water system. During this period, the facility's cooling-water dependent operations would most likely be halted, with a potential loss of revenue and income from those operations. Accordingly, a key element of the cost to facilities in complying with the 316(b) Phase III regulation is the loss in income from installation downtime. Installation downtime may also present a cost to society, depending upon assumptions about the cost structure of the production to replace the goods and services not produced by complying facilities during the installation downtime.

Unlike the capital and operating cost elements of total compliance cost, this cost element is not estimated based solely on engineering analysis of compliance technology specifications. Instead, the cost of installation downtime depends on a number of factors additional to the engineering assessment of compliance requirements. Specifically, the cost of installation downtime depends on the estimated length of time that a facility's cooling water intake system would be removed from service, the extent to which the facility's business operations depend on cooling water, and the revenue and operating cost structure of those cooling water dependent operations. Of these items, the length of time that the facility's cooling water intake system would be out of service was estimated as part of the engineering analysis of compliance requirements. The remaining items – the extent to which the facility's business operations depend on cooling water, and the revenue and operating cost structure of the facility's cooling water dependent operations – were obtained from the facility's response to the economic/ financial section of the 316(b) Phase III questionnaire. EPA used this information to calculate the pre-tax income loss from installation downtime.

The following sections of this appendix presents the methodology used to estimate the income loss from installation downtime.

B3A2-1 ESTIMATED SHUT-DOWN PERIOD FOR INSTALLING COMPLIANCE EQUIPMENT

Installation of some of the compliance technologies considered for the proposed regulation would require a one-time, temporary shut-down of the facility's cooling water intake system. Table B3A2-1, below, lists the estimated durations of net system downtime, in weeks, for each of the compliance technology modules considered for compliance with the 316(b) Phase III regulation. The *net* downtime duration accounts for any expected annual period of cooling water system downtime for regular maintenance and repair – the net downtime is the number of weeks the cooling water system would need to be out of service above and beyond any regular maintenance downtime period. Most of the technology modules are expected to be able to be installed without any additional net system downtime. However, several of the technology modules are expected to require a net downtime ranging from a month or less to nearly three months.

Table B3A2.1: Estimated Average Cooling Water System Downtime by Technology Module

Module #	Description	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.

B3A2-2 CALCULATING THE IMPACT OF INSTALLATION DOWNTIME ON COMPLYING FACILITIES

Installation downtime may affect a facility's business operations in several ways:

1. The facility will be unable to perform production or other business operations that depend on cooling water.

2. The facility will lose revenue from the production and sale of the goods and services that otherwise would have been produced by the affected production operations during the period of downtime.

3. The facility will shed the variable cost of producing the goods and services not able to be produced during the period of installation downtime. However, the facility will continue to incur the fixed costs of production associated with the affected operations.

4. If, as part of its cooling water dependent operations, the facility generates electricity for its own use, and some part of this self-generated electricity continues to be needed during the period of installation downtime, the facility may need to purchase replacement electricity.

Together, these effects lead to a loss in pre-tax income, which EPA calculated and used as the cost of installation downtime in its analysis of facility impacts. EPA calculated the loss in pre-tax income by first calculating the *annual* loss in revenue in cooling water dependent operations *less* the variable production costs associated with those operations *plus* the cost of purchasing electricity to replace any own-generated electricity that is used by the facility. Second, EPA adjusted this *annual* pre-tax loss value to reflect the length of net installation downtime as estimated in the engineering analysis of compliance technology requirements. Specific elements of these calculations are summarized below for: (1) business effects not associated with electric power generation and (2) electric power generation-related effects.

Business Effects Not Associated with Electric Power Generation

The 316(b) Phase III questionnaire included a series of questions aimed at understanding the potential financial effect of temporary or permanent shutdown of a facility's cooling water intake system. A key data item obtained from the questionnaire response is the fraction of a facility's non-electric revenue that depends on cooling water. This information coupled with facility income statement information obtained from the questionnaire response provided the basis for calculating the income loss in non-electric power-related operations. Steps in the calculation are as follows:

1. Calculate the annual revenue loss from curtailment of cooling water-dependent operations by multiplying the fraction of cooling water-dependent revenue *times* total reported non-electric revenue.

2. Calculate the variable production cost offset to this revenue loss by multiplying *materials expense*, as reported on the facility's income statement provided in the questionnaire, *times* the fraction of cooling water-dependent revenue, as described above. This approach assumes that the variable production cost structure for cooling water-dependent operations is the same as that for non-cooling water-dependent operations. The use of *materials expense* as the only component of facility operating costs that may be shed during a period of installation downtime, is relatively conservative as other cost accounts might also be able to be curtailed or the services provided by those accounts – e.g., labor – applied to some other beneficial service within the enterprise.

3. Calculate *annual* loss in pre-tax income from curtailment of the facilities cooling water intake system *from non-electric power-related operations* as estimated revenue loss *less* estimated reduction in variable production cost.

4. Calculate pre-tax income loss in non-electric power-related operations, from installation downtime, by multiplying the annual pre-tax income loss by the fraction of the year indicated as the net downtime required for installing compliance equipment.

Business Effects Associated with Electric Power Generation

The analysis of installation downtime costs for cooling water-dependent electric power generation activities is the same in concept as that outlined for non-electric power-related operations, with the exception that facilities may need to incur an additional cost for purchasing replacement electricity if some of the facility's electric power needs were met from its own generation. Key information obtained from facility questionnaires for calculating the income loss in electric power-related operations includes: (1) annual electric revenue reported as cooling water dependent, (2) the fuel cost of electric power generation, which is assumed to be shed during the period of curtailed operations, (3) the quantity of electricity consumed by the facility, and (4) the quantity of electricity generated by the facility. The remaining key input required for this analysis is the unit price of replacement electricity: for this item, EPA used the average electricity price for industrial customers by state, using data from the Department of Energy, Energy Information Administration, for 2002/2003. EPA calculated the pre-tax income loss effect for electric power generation activities as follows.

1. Annual electric revenue from cooling water-dependent generation is obtained directly from the facility questionnaire. This value is assumed to be the annual revenue loss in electric power generation, from curtailment of cooling water-dependent operations.

2. Annual fuel cost of electric power generation is obtained directly from the facility questionnaire. This value is assumed to be shed during the period of curtailed operations.

3. Calculate own-generated electricity that is consumed by the facility as the lesser of (a) the facility's own electricity generation or (b) the electricity used within the facility.

4. Calculate the quantity of replacement electricity to be purchased by the facility, by multiplying the quantity of own-generated electricity that is consumed by the facility *times* the fraction of non-electric revenue that is cooling water dependent *but subject to* a maximum reduction in electricity need of 75 percent. That is, the facility is assumed to need replacement electricity in proportion to the fraction of non-electric revenue *that is not cooling water-dependent.* As the fraction of revenue dependent on cooling water, and thus affected by installation downtime, increases, the need for replacement electricity decreases. However, even in the case where the fraction of revenue that is cooling water dependent is very large (e.g., 100 percent), the analysis assumes that the facility will not shed all of its electricity need: the facility is assumed to always require 25 percent of its baseline electricity consumption from own-generated electricity. The assignment of the 25 percent minimum electricity replacement need is somewhat arbitrary but reflects the reality that less electricity is likely to be needed to serve a lower level of operations during a cooling water system shutdown, while also acknowledging that all electricity need cannot be shed, regardless of the reduction in non-electric generating activity. The numerical consequence on imposing the 25 percent electricity requirement floor (as opposed to a floor of zero percent) is very small.

5. Calculate the cost of electricity purchased to replace own-generated electricity used by the facility by multiplying the quantity of replacement electricity *times* the average electricity price, by state, for industrial customers.

6. Calculate *annual* loss in pre-tax income for electric power-related operations as estimated revenue loss from cooling water-dependent generation *less* estimated annual fuel cost of electric power generation *plus* cost of electricity purchased to replace own-generated electricity.

7. Calculate pre-tax income loss in electric power-related operations, from installation downtime, by multiplying the annual pre-tax income loss by the fraction of the year indicated as the net downtime required for installing compliance equipment.

These values are summed to yield the total pre-tax income loss to the facility from installation downtime.

Under the 50 MGD All Option, 19 manufacturing facilities have non-zero downtime. Of these, 18 have non-zero cost of downtime. The facility with no downtime costs reported that none of its revenue was cooling water dependent. Of the 18 facilities with non-zero downtime cost, downtime cost as a fraction of annual revenue ranges from 0.3% to 14.6%. Under the 200 MGD All Option, 3 manufacturing facilities have non-zero downtime. Of these, all 3 have non-zero cost of downtime. Of the 3 facilities with non-zero downtime cost, downtime cost as a fraction of annual revenue ranges from 0.3% to 3.0%. Under the 100 MGD SWB Option, 9 manufacturing facilities have non-zero downtime. Of these, all 9 have non-zero cost of downtime. Of the 9 facilities with non-zero downtime cost, downtime cost as a fraction of annual revenue ranges from 0.3% to 3.0%.

B3A2-3 CALCULATING THE COST TO SOCIETY OF INSTALLATION DOWNTIME

The preceding discussion describes the calculation of the pre-tax income loss from installation downtime as used in the facility impact analysis. For the analysis of cost to society, the concept of cost of installation downtime differs from that for the private impact analysis. Specifically, under the assumption that the total quantity of goods and services produced and sold by the affected industries would not change as a result of the regulation (see Chapter E1 for further detail on the social cost analysis framework), the cost to society from installation downtime is the *increase* in cost for producing the goods and services that would otherwise have been produced by the affected facilities. That is, other producers are assumed to replace the production of goods and services lost due to installation downtime, and the cost to society is the amount, if any, by which the cost of these goods and services exceeds the cost at which the affected facilities would have produced these goods and services.

In concept, the cost to society could vary over a broad range depending on the structure of, and character of competition in, the production of goods and services in the individual markets affected by the 316(b) Phase III regulation.

- At the low end of this possible range, if the replacement goods and services can be provided by other producers at the same variable production cost as otherwise would have been incurred by the affected 316(b) Phase III facilities, then the cost to society of installation downtime would be zero. Because the cost for alternative producers is the same as for the producers incurring downtime, society incurs no incremental resource cost when other producers provide the replacement goods and services. In this case, although the affected 316(b) Phase III facilities incur a financial impact from installation downtime, this impact – the loss in pre-tax income described in the preceding section – becomes a transfer from the producers incurring installation downtime losses to the producers who make up the lost production.

- At the high end of this possible range, the cost to society would be approximately equal to the pre-tax income loss incurred by facilities due to installation downtime. That is, the cost to society would again be the lost revenue from installation downtime *less* the variable cost of producing the goods and services not produced due to the installation downtime. In this case, the variable production cost for other producers to replace the lost goods and services is assumed to be essentially the same as the *price* received for the sale of the goods and services not produced by the facilities incurring the installation downtime. This assumption is consistent with a competitive market model of increasing marginal production cost, such that the variable production cost of the marginal supplier of goods and services produced and sold in any period is approximately equal to the price received for those goods and services in the market.

The likely reality is that the cost to society from installation downtime lies somewhere between these cases. Lacking specific knowledge of the overall production cost structure of the affected industries and for the numerous goods and services provided by the affected industries, *to be conservative in its analysis*, EPA adopted the latter of the two analytic cases outlined above for its analysis. That is, EPA assumed that the cost to society from installation downtime would be the same as that estimated as the pre-tax cost of installation downtime for Manufacturers facilities. To the extent that the variable production cost for replacement goods and services is less than the selling price of those goods and services, this assumption overstates the cost to society of installation.

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Appendix 3 to Chapter B3: Cost Pass-Through Analysis

INTRODUCTION

This appendix presents the assessment of cost pass-through (CPT) potential for five key manufacturing industries in which a substantial number of facilities are expected to be subject to the Section 316(b) Phase III regulation. The five industry sectors considered in this analysis are:

- SIC 26: Paper and allied products
- SIC 28: Chemicals and allied products
- SIC 29: Petroleum and coal products
- SIC 331: Steel
- SIC 333/5: Aluminum

APPENDIX CONTENTS

The purpose of the CPT analysis is to estimate the extent to which cost increases incurred by facilities in complying with the proposed Section 316(b) Phase III regulation can be reasonably expected to be passed on to consumers in the form of higher prices.

This appendix begins with a review of approaches for assessing CPT potential associated with market-wide cost increase scenarios. Next, a description of the methodology and specific metrics used to assess CPT potential are discussed and the results for each sector provided. Finally, conclusions are presented.

From this analysis, EPA concluded that an assumption of zero cost pass-through is appropriate for analyzing the impact of the Phase III regulation on facilities in the manufacturing industries. Performance of the financial impact analysis under this assumption means that facilities must absorb all compliance-related costs and operating effects (e.g., income loss from facility shutdown during equipment installation) within their baseline cash flow and financial condition. To the extent that facilities would be able to pass on some of the compliance costs to customers through price increases, the analysis overstates the potential impact on complying facilities. Thus, this assumption is conservative in avoiding potential overstatement of the manufacturing industries' ability to absorb the costs of 316(b) regulation compliance without material adverse economic/financial impact.

B3A3-1 THE CHOICE OF FIRM-SPECIFIC VERSUS SECTOR-SPECIFIC CPT COEFFICIENTS

One method of examining the ability of a firm to pass-through compliance-related cost increases associated with the Phase III regulation is to review the firm's historical performance in passing on previous cost increases to consumers. For example, Ashenfelter *et al.* (1998) estimate the cost pass-through rate facing an individual firm, and distinguish that rate from the rate at which a firm passes through cost changes common to all firms in an industry, by regressing the price a firm charges on both its costs and the costs of another firm in the industry. The estimated firm-specific CPT rate relates a change in the prices charged by a specific firm to a change in its production costs, assuming no changes in the production cost for rival producers of that product. However, estimating firm specific CPT rates is extremely complex. For example, in order to estimate firm-specific CPT rates for every Phase III manufacturing firm included in the sample of Detailed Industry Questionnaire (DQ) respondents, EPA would require, for each firm, detailed information on the products sold, the markets in which these products are sold, as well as information identifying major competitors in each market. The Detailed Industry Questionnaire did not obtain this information from surveyed facilities. And even if such information were available, the analysis would remain highly challenging and subject to significant analytic error. As such, it is neither possible nor practical to develop firm-specific CPT coefficients for the sample of Phase III manufacturers.

Moreover, even if the Agency possessed the data necessary to estimate firm-specific CPT rates, it is questionable whether these rates would be the appropriate measure of CPT potential for compliance-related cost increases stemming from the Phase III regulation. The Phase III regulation would force multiple firms in each of the industry sectors considered in this analysis to incur compliance-related cost increases, which implies that for most firms the cost increases would not only apply to them, but also to several of their competitors. Not surprisingly, previous studies have found that the CPT rate for changes to an individual firm's cost differs from the rate at which a firm would pass through cost changes that are common to all, or a substantial fraction of, firms in an industry (Ashenfelter et al., 1998). It can be reasonably expected that the higher the share of firms incurring the cost increase, or more appropriately the higher the share of total output produced by such firms, the greater the ability of those firms to pass on a greater portion of those costs to the consumer.

In cases where an industry-wide cost shock occurs, an industry-wide CPT rate would be an appropriate and practical way of assessing the potential of all firms in that industry to pass through that cost increase to consumers (EPA, 2003). An industry-wide CPT rate provides an estimate of the change in each facility's output prices as a function of the increase in its production costs, assuming that the same cost increase is experienced by all firms in the industry. Such an industry-wide rate is relatively easier to estimate than firm-specific cost pass-through rates if one assumes that perfect competition exists in the industry. Among other things, perfect competition implies the existence of product homogeneity within the industry, homogeneity of production technology among firms in the industry, and homogeneity of production costs among firms (i.e., pricing is at marginal cost). Under these conditions, the price response to a general industry-wide change in production costs is likely to be industry-wide and similar across all firms. For example, in support of the recently promulgated Metal Products &Machinery (MP&M) industry effluent guidelines, EPA's Office of Water (OW) estimated industry-specific CPT rates since a large fraction of establishments in these industries were expected to be subject to the regulation. EPA estimated these CPT rates by regressing annual output price indices on annual input cost indices for the MP&M industry. The estimated CPT coefficients were validated by a market structure analysis which assessed, for each industry, the potential market power enjoyed by firms in the industry and the consequent implications it had on their ability to pass through compliance-related costs.

Industry-wide CPT rates can be estimated for the Phase III manufacturing sectors based on the methodology used for deriving industry-wide CPT rates for industries covered by the MP&M regulation. However, because the proposed regulation would only affect those facilities that operate a CWIS to withdraw cooling water from surface waterbodies, only a subset of facilities in each industry sector would incur compliance-related cost increases. As the cost increase associated with the proposed regulation is not industry-wide, it is questionable whether industry-wide CPT rates are appropriate for estimating the price response of firms in the five industry sectors considered in the analysis of Phase III impacts. If a substantial portion of production in each industry occurs at facilities not subject to the proposed regulation, then the use of industry-wide CPT rates may grossly overestimate the ability of firms in these industries to pass-through compliance-related costs to consumers.

To assess the reasonableness of using industry-wide CPT rates in the analysis of impacts to Phase III manufacturers, EPA estimated the percentage of total production in each of the five industry sectors considered in this analysis that occurs at facilities potentially subject to compliance-related cost increases. Value of shipments, a measure of the dollar value of production, was selected for the basis of this estimate. Because value of shipments data were not collected using the DQ, these data were not available for the sample of Phase III manufacturing facilities potentially subject to the proposed regulation. As such, total revenue, as reported on the DQ, was used as a close approximation to value of shipments for these facilities. EPA estimated the total revenue subject to the proposed regulation by multiplying the 1998 revenue of facilities in the sample of Phase III manufacturers that were determined to be potentially subject to the proposed regulation by their facility sample weights and summing across all facilities. Total value of shipments estimates for each industry were obtained from the 1998 Annual Survey of Manufacturers. Table B3A3.1 summarizes the findings of this analysis.

Table B3A3.1: Proportion of Value of Shipments Potentially Subject to Compliance-Related Costs Associated with the Phase III Regulation (1998)

SIC	Industry Sector	Revenue for Facilities Subject to Phase III Regulation (Millions 1998$)	Total Value of Shipments (Millions 1998$)	Proportion of Total Value of Shipments Potentially Subject to Phase III Regulation
26	Paper and allied products	$55,143	$84,911	65%
28	Chemicals and allied products	$61,179	$268,000	23%
29	Petroleum and coal products	$47,832	$118,156	40%
331	Steel	$38,423	$76,182	50%
333/35	Aluminum	$12,096	$19,266	63%

Notes: For the purpose of this analysis, facility revenue was used as an appropriate surrogate in the absence of value of shipments for sample facilities.

Source: Section 316(b) Detailed Industry Questionnaire and 1998 Annual Survey of Manufacturers.

As shown in Table B3A3.1, the proportion of total value of shipments potentially subject to the Phase III regulation ranges from 23 percent to 65 percent depending on the industry considered. The actual proportion of total value of shipments subject to regulation-induced compliance costs would be smaller since not all of the potentially regulated facilities would be subject to meet the national categorical requirements of the proposed Phase III regulation: that is, facilities below the proposed design intake flow (DIF) would be subject to permitting based on best professional judgement (BPJ) rather than based on national standards, and several facilities currently employ baseline technologies that meet the requirements of the proposed regulation. Given that less than 65 percent of the total value of shipments in each of the five industries considered in this analysis would be subject to regulation induced compliance costs, and the likelihood that these percentages represent upper bound estimates, EPA believes that the theoretical threshold for justifying the use of industry-wide CPT rates in the Phase III impact analysis has not been met. The Agency believes that using industry-wide CPT rates in the analysis of Phase III impacts would overestimate the cost pass-through ability of firms incurring regulation-induced compliance costs, and thus underestimate impacts. At the other end of the spectrum, however, an assumption of zero CPT would provide a conservative estimate as it would assume that all facilities incur one hundred percent of cost impacts.

Given the inability to estimate firm-specific CPT rates and the finding that the use of industry-wide CPT rates would not be appropriate, EPA next conducted a market structure analysis to investigate the extent to which firms in the five industry sectors enjoy sufficient market power to pass compliance-related costs on to consumers in the form of higher prices.

B3A3-2 MARKET STRUCTURE ANALYSIS

Information on the competitive structure and market characteristics of an industry provide insight into the likely ranges of supply and demand elasticities and the sensitivity of output prices to input costs. For example, when input costs increase, the profit-maximizing firm attempts to maintain its profits by increasing output prices, to the extent permitted by market power. The amount of the cost increase that the firm can pass on as higher prices depends on the relative market power of the firm and its customers. The market structure analysis described in this section attempts to measure the market power enjoyed by firms in each of the five industries. This analysis is combined with information from industry review documents such as *McGraw Hill's U.S. Industry and Trade Outlook* to reach conclusions regarding the CPT ability of firms in each industry.

The market structure analysis consists of a review of economic data for the following four indicators of market power: industry concentration; import competition; export competition; and long term growth. Each of these indicators is discussed in detail below. EPA notes that the impact of each of these four indicators of market power varies from industry to industry. Furthermore, the results presented for each indicator must be interpreted with caution because even though for a particular industry an indicator may predict high cost pass-through potential, the specific features of the industry may result in the indicator having diminished significance in predicting market power.

B3A3-2.1 Industry Concentration

The extent of concentration among a group of market participants is an important determinant of that group's market power. A group of many small firms typically has less market power than a group of a few large firms, because the latter are in a more advantageous position to collude with each other. All else being equal, highly-concentrated industries are therefore expected to pass-through a higher proportion of the compliance costs that would result from the Phase III regulation.

This analysis uses the Herfindahl-Hirschman Index (HHI) as a measure of market concentration[1]. The HHI is calculated by squaring the market share of each firm competing in the market and then summing the resulting numbers. For example, for a market consisting of four firms with shares of thirty, thirty, twenty and twenty percent, the HHI is 2600 ($30^2 + 30^2 + 20^2 + 20^2 = 2600$). The HHI takes into account the relative size and distribution of the firms in a market and approaches zero when a market consists of a large number of firms of relatively equal size. The HHI increases both as the number of firms in the market decreases and as the disparity in size between those firms increases. Based on the U.S. Department of Justice's guidelines for evaluating mergers, markets in which the HHI is under 1000 are considered unconcentrated, markets in which the HHI is between 1000 and 1800 are considered to be moderately concentrated, and those in which the HHI is in excess of 1800 are considered to be concentrated.

The accuracy of any analysis of market power originating from industry concentration depends to a large extent on properly defining the relevant market. A well-defined market requires the inclusion of all competitors and the exclusion of all non-competitors. Defining the relevant market too narrowly overstates market power, while defining the market too broadly would underestimate it. The four-digit SIC category, while not a perfect delineation, is most often used by industrial organization economists in their studies because, among publicly available data sources, these industries appear to correspond most closely to economic markets (Waldman & Jensen, 1997). Therefore, in Table B3A3.2 below, industry concentration data is presented for each of the four-digit SIC codes that include at least one potentially regulated Phase III facility for which DQ data are available.

[1] The Herfindahl-Hirschman Index was chosen because it provides a more complete picture of industry concentration compared to other measures such as the four-firm and eight-firm concentration ratios. The HHI uses the market shares of all the firms in the industry, and these market shares are squared in the calculation to place more weight on the larger firms. In contrast, the four- and eight-firm concentration ratios do not use the market share of all firms in the industry, and nor do they provide information about the distribution of firm size. For example, if there were a significant change in the market shares among the firms included in the ratio, the value of the concentration ratio would not change.

Table B3A3.2: Herfindahl-Hirschman Index for Four-Digit SIC

SIC	SIC Description	Industry	HHI
	Unconcentrated Markets (HHI < 1,000)		
2679	Converted Paper Products, N.E.C.	Paper and Allied Products	143
2899	Chemical Preparations, N.E.C.	Chemicals and Allied Products	190
3317	Steel Pipe and Tubes	Steel	194
3315	Steel Wire and Related Products	Steel	201
2821	Plastics Materials and Resins	Chemicals and Allied Products	284
2869	Industrial Organic Chemicals, N.E.C.	Chemicals and Allied Products	336
2834	Pharmaceutical Preparations	Chemicals and Allied Products	341
2621	Paper Mills	Paper and Allied Products	392
2911	Petroleum Refining	Petroleum and Coal Products	414
2865	Cyclic Crudes and Intermediates	Chemicals and Allied Products	428
2631	Paperboard Mills	Paper and Allied Products	438
3312	Blast Furnaces and Steel Mills	Steel	551
3316	Cold Finishing of Steel Shapes	Steel	604
2819	Industrial Inorganic Chemicals, N.E.C.	Chemicals and Allied Products	677
2873	Nitrogenous Fertilizers	Chemicals and Allied Products	792
2611	Pulp Mills	Paper and Allied Products	858
	Moderately Concentrated Markets (1,000 < HHI < 1,800)		
3313	Electrometallurgical Products	Steel	1,103
2676	Sanitary Paper Products	Paper and Allied Products	1,451
3334	Primary Aluminum	Aluminum	1,456
2874	Phosphatic Fertilizers	Chemicals and Allied Products	1,528
2841	Soap and Other Detergents	Chemicals and Allied Products	1,584
2813	Industrial Gases	Chemicals and Allied Products	1,629
3353	Aluminum Sheet, Plate, and Foil	Aluminum	1,633
	Concentrated Markets (1,800 < HHI)		
2816	Inorganic Pigments	Chemicals and Allied Products	1,910
2812	Alkalies and Chlorine	Chemicals and Allied Products	1,994
2824	Organic Fibers, Noncellulosic	Chemicals and Allied Products	2,158
2833	Medicinals and Botanicals	Chemicals and Allied Products	2,999

Notes: HHI not available for SIC 2823.

Source: Economic Census 1992.

Table B3A3.2 reveals that based on their HHI, 16 four-digit SIC markets can be classified as unconcentrated, 7 can be classified as moderately concentrated, and only 4 can be classified as concentrated. Notably, all 4 of the four-digit SIC categories listed as being concentrated belong to the Chemicals and Allied Products industry. From a market power perspective, Table B3A3.2 seems to suggest that at the four-digit SIC level only four SIC categories are sufficiently concentrated to argue that firms may possess sufficient market power to pass-through a portion of their compliance-related costs assuming that competitor firms in the same industry do not incur similar cost increases.

To further examine the level of concentration in each of the five industry sectors, EPA decided to analyze HHI at the industry level as well. The Industry-level HHI for each sector was calculated as the average of each four-digit SIC HHI belonging to that sector, weighted by the value of shipments for that SIC. EPA notes that aggregating HHI for four-digit SIC categories into industry HHI are likely to yield estimates that in general understate market power. Nonetheless, estimated industry HHI should still provide meaningful insight into market power of firms in the industry because firms in each industry still produce similar or related products (for example, paper products, chemicals, and etc.). Estimated Industry HHI are presented below in Table B3A3.3.

Table B3A3.3: Herfindahl-Hirschman Index by Industry

SIC	Industry	HHI
29	Petroleum and Coal Products	414
331	Steel	478
26	Paper and Allied Products	643
28	Chemicals and Allied Products	715
333/5	Aluminum	1,570

Source: U.S. EPA Analysis, 2004.

Table B3A3.3 reveals that, at the industry level, the estimated HHI for four of the five industries are quite small, implying that they are unconcentrated markets and within these industries individual firms do not enjoy much market power. Notably, the Chemicals and Allied Products industry has a low HHI, which suggests that the 4 four-digit SIC categories that were classified as having concentrated markets in reality make up a very small segment of the Chemicals and Allied Products industry. Thus, from the perspective of the Phase III regulation, the majority of firms in this industry have small market power. In addition, EPA notes that only 23 percent of production in this is industry would potentially be subject to compliance-related cost increases, which suggests that the cost pass-through potential of firms from this sector incurring such expenses would be severely curtailed.

An important finding in Table 3 is that the Aluminum industry, which is categorized at the three-digit SIC level, appears to be moderately concentrated. Thus, based solely on an analysis of industry concentration, it would appear that firms in the Aluminum industry may enjoy moderate amounts of market power, which may enable them to pass through costs at a more than negligible rate. However, as cautioned at the beginning of the market structure analysisok, an accurate judgement of the market power enjoyed by firms in an industry must be reserved until all indicators have been analyzed.

B3A3-2.2 Import Competition

Theory suggests that imports as a percent of domestic sales are negatively associated with market power because competition from foreign firms limits domestic firms' ability to exercise such power. Firms belonging to sectors in which imports make up a relatively large proportion of domestic sales would therefore be at a relative disadvantage in their ability to pass-through costs compared to firms belonging to sectors with lower levels of import penetration, the measure of import competition used in this analysis. Import penetration, the ratio of imports in a sector to the total value of domestic consumption in that sector, is particularly relevant because foreign producers would not incur costs as a result of the Phase III regulation.

In this market structure analysis, EPA assumes that higher import penetration will generally imply that firms are exposed to greater competition from foreign producers and would thus possess less market power to increase prices in response to regulation-induced increases in production costs. EPA estimated import penetration ratios for each industry as total imports in an industry divided by total value of domestic consumption in that industry; where domestic consumption equals domestic production plus imports minus exports. Import penetration ratios estimated using 1998 census data for the five industry sectors considered in this analysis are presented below in Table B3A3.4.

Table B3A3.4: Import Penetration by Industry

SIC	Industry	Imports (Millions of 1998$)	Implied Domestic Consumption (Millions of 1998$)	Import Penetration
26	Paper and Allied Products	$13,137	$85,865	15%
28	Chemicals and Allied Products	$44,570	$263,404	17%
29	Petroleum and Coal Products	$10,711	$120,112	9%
331	Steel	$19,221	$88,645	22%
333/5	Aluminum	$5,189	$20,063	26%

Notes: Implied Domestic Consumption = Value of Shipments + Imports - Exports.

Source: 1998 U.S. Bureau of Census data.

The estimated import penetration ratios for the five industries range from 9 percent to 26 percent for the year 1998. The estimated import penetration ratio for the entire U.S. manufacturing sector (SIC 20-39) for the same year is 19 percent. Considering that the United States is an open economy, EPA believes it is reasonable to assume that in industries with import penetration ratios close to or above 19 percent domestic firms most likely face stiff competition from foreign firms. Such competition is likely to curtail the market power enjoyed by domestic firms and given the scenario that regulation-induced cost increases are not incurred by foreign producers would limit the ability of domestic firms to pass-through such costs. Thus, based on the import penetration ratios presented in Table 4, only firms in the Petroleum and Coal Products Industry appear to be in a position to pass-through to consumers a significant portion of compliance-related costs associated with the Phase III regulation. However, given the low HHI for this industry EPA believes that existing market competition among domestic firms most likely nullifies any favorable influence the lack of foreign competitors would have on increasing the market power of firms in this industry. EPA also highlights the above average import penetration ratios for the Steel and Aluminum industries which suggest low market power for firms in this industry. With respect to the Aluminum industry, this fact may offset – from a market power perspective – the finding that the industry was identified above as being moderately concentrated. Thus, even though there are relatively few domestic producers in the U.S. Aluminum industry, the notable presence of foreign producers in U.S. markets is likely to markedly reduce their the market power.

B3A3-2.3 Export Competition

The Phase III regulation would not increase the production costs of foreign producers with whom domestic firms must compete in export markets. As a result, firms in industries that rely to a greater extent on export sales would have less latitude in increasing prices to recover cost increases resulting from regulation-induced increases in production costs. They would therefore have a lower CPT potential, all else being equal.

This analysis uses export dependence, defined as the percentage of shipments from an industry that is exported, to measure the degree to which a sector is exposed to competitive pressures abroad in export sales. Firms in industries with relatively high export dependence are expected to have lesser market power than those in industries with relatively low export dependence due to their relatively larger reliance on sales in export markets. Estimated export dependence ratios estimated using 1998 census data for the five industry sectors considered in this analysis are presented below in Table B3A3.5.

Table B3A3.5: Export Dependence by Industry

SIC	Industry	Exports (Millions of 1998$)	Value of Shipments (Millions of 1998$)	Export Dependence
26	Paper and Allied Products	$10,051	$82,778	12%
28	Chemicals and Allied Products	$49,932	$268,765	19%
29	Petroleum and Coal Products	$5,038	$114,439	4%
331	Steel	$5,268	$74,692	7%
333/5	Aluminum	$2,951	$17,825	17%

Source: 1998 U.S. Bureau of Census data.

The estimated export dependence ratios for the five industries range from 4 percent to 19 percent for the year 1998. The estimated export dependence ratio for the entire U.S. manufacturing sector for the same year is 23 percent. Thus, for all five industries, their export dependence ratio is below the average for the U.S. manufacturing sector. This finding implies that none of the five industries are characterized by strong competitive pressures from foreign firms/markets, and thus market power and CPT potential are not diminished by export dependence. However, it is questionable whether this effect works as strongly in the opposite direction, i.e., firms in an industry will have a comparatively high cost pass-through potential simply because firms in that industry are not active in export markets. From the standpoint of firms gaining market power, EPA believes that the finding of low export dependence diminishes the importance of export competition as an indicator of market power. Thus, the other three indicators must be relied upon to gauge the amount of market power that firms in each industry are expected to hold. For example, even though the Petroleum and Coal Products and Steel industries have extremely low export dependence, the low market concentration in these industries leads EPA to believe that market power held by individual firms is likely to be quite small. In addition, as discussed later in this memo, recent trends in the Steel industry provide good reason to believe that firms in this industry are unlikely to be able to pass through a notable portion of regulation-induced cost increases given the current business environment they face.

B3A3-2.4 Long-Term Industry Growth

An industry's competitiveness and the ability of firms to engage in price competition are likely to differ between declining and growing industries. Most studies have found that recent growth in revenue is positively related to profitability (Waldman & Jensen, 1997), which suggests a greater ability to recover costs fully.

To examine trends in long-term growth for each of the five industry sectors considered in this analysis, EPA estimated the average annual growth rate in the value of shipments between 1989 and 1998 for each industry using data available from the U.S. Bureau of Census[2]. EPA expects firms in sectors with higher growth rates to be better positioned to pass through compliance costs rather than being forced to absorb such cost increases in order to retain market share and revenue. The results of this analysis are presented in Table B3A3.6.

[2] The period from 1989 to 1998 represents the most recent ten year period that includes data consistent with the survey period for the Detailed Industry Questionnaire (1996-1998).

Table B3A3.6: Average Annual Growth Rates by Industry

SIC	Industry	Average Annual Growth Rate in Value of Shipments (1989 to 1998)
26	Paper and Allied Products	-0.3%
28	Chemicals and Allied Products	1.5%
29	Petroleum and Coal Products	0.6%
331	Steel	0.4%
333/5	Aluminum	-2.2%

Notes: Average Annual Growth Rate for the Petroleum and Coal Products industry has been estimated for the years 1989 to 1997. The reported value of shipments for this industry in 1998 is significantly lower than in earlier years and therefore was excluded from this analysis as an outlier.

Source: U.S. Bureau of Census data.

Table B3A3.6 shows that of the five industries specifically considered for this analysis, two industries experienced negative growth over the 1989 to 1998 time period and another two experienced only marginal growth. Only the Chemicals and Allied Products industry experienced what may be qualified as moderate growth, displaying an average annual growth rate of 1.5 percent. Based on the *U.S. Industry and Trade Outlook '99*, annual growth in manufactures over the period 1993 to 1998 was over 2 percent in all years, and over 4 percent in four of the six years in that period (the figures reported for 1997 and 1998 are estimates). An examination of the growth rate for the Chemicals and Allied Products industry for the same six year period (1993-98) revealed a growth rate of 2.4 percent. Comparing the average annual growth rate for the Chemicals and Allied Products industry with that of the entire manufacturing sector, and comparing overall growth in this sector with the growth experience by the manufacturing sector taken as a whole between 1993 and 1998 suggests that its performance in general was below average. Thus, in the absence of strong growth performance during the 1990s for all five industries, it is unlikely that firms in any of these industries acquired significant market power on account of growing demand for their products. In effect, the long-term growth performance of all five industries does not support a conclusion that firms in these industries are in a strong position to pass on a significant portion of their compliance costs.

B3A3-2.5 Conclusions

Given that less than 65 percent of the total value of shipments in each of the five industries considered in this analysis would be subject to regulation-induced compliance costs, and the likelihood that these percentages represent upper bound estimates, the likelihood that firms incurring such costs would be able to pass through to consumers a material portion of 316(b) compliance costs is small. To validate this hypothesis, EPA undertook the market structure analysis presented in the previous section. In general, the weight of evidence from the market structure analysis suggests that firms in all five industries are unlikely to posses significant amounts of market power, thereby lending support to EPA's hypothesis that most firms would not be in a position to pass-through a significant portion of compliance costs.

The analysis of individual indicators under the market structure analysis did reveal a few exceptions to the general finding of low market power in all industries. However, considering the combined impact of all four indicators of market power together with information on recent economic trends in these industries suggests that on the whole, firms in each of the five industries hold relatively low market power and CPT potential. For example, the estimated HHI for the Aluminum industry indicated that this sector is moderately concentrated, which would potentially allow firms in this industry to pass through a significant portion of their compliance-related costs. In contrast, however, the market structure analysis also found that the domestic Aluminum industry witnessed a sustained decline in production during the 1990s and also faces stiff competition from foreign producers in its U.S. markets. As discussed in the profile of this industry, in the early 1990s the domestic Aluminum industry was affected by reduced U.S. demand and the dissolution of the Soviet Union, which resulted in dramatic increases in Russian exports of aluminum. The recovery that followed was subsequently affected by the economic crises in Asian markets in the second-half of the 1990s, which along with growing Russian exports, again resulted in a period of oversupply. These trends, which are reflected in the negative average annual growth rate and high import penetration for the domestic Aluminum industry, suggest that domestic firms in this industry hold relatively low market power and are not in a position to pass through significant portions of their compliance-related cost increases. Overall, the balance of the argument in favor of and against high cost pass-through in the Aluminum industry rests with the indicators that argue against it; the lack of domestic competition in the industry is more than offset by the existence of stiff competition from foreign producers and the general decline witnessed by the domestic industry. Similarly, in the case of all other exceptions found in the market structure analysis, the weight of evidence – when all four indicators of market power are considered together – rests with the indicators that suggest low market power and CPT potential.

Based on the findings of the market structure analysis, EPA decided to assume a zero CPT rate for all five industries in the analysis of Phase III impacts. EPA believes that this assumption is reasonable given the results of the market structure analysis and is definitely superior to using industry-wide CPT rates. In addition, EPA notes that by assuming a CPT rate of zero for all industries, the analysis of Phase III impacts takes a conservative approach in that the analysis assumes that facilities would incur one hundred percent of compliance costs. Thus, whereas an overstated CPT rate may erroneously underestimate impacts for facilities incurring compliance-related cost increases, the use of a conservative CPT rate of zero errs on the side of caution, thus potentially overstating impacts to affected facilities.

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Appendix 4 to Chapter B3: Adjusting Baseline Facility Cash Flow

INTRODUCTION

CHAPTER CONTENTS

To support its analysis of the economic impact of the 316(b) Phase III regulation, EPA collected economic/financial data for the three years 1996-1998 from a sample of facilities in the manufacturing industries primarily expected to be subject to the Phase III regulation. These facility economic/financial data are used to gauge the potential economic/financial impact of regulatory compliance: the facilities and their financial data serve as models for testing the financial effect of regulatory alternatives. For this analysis to provide valid insight into the ability of the affected industries to meet regulatory requirements without material adverse impact, the sample facility data should reflect business conditions that might be reasonably anticipated at the time of compliance.

In performing its impact analyses using these data, EPA was concerned in two ways that the facility survey data might yield erroneous conclusions.

- First, knowing that U.S. business conditions during the latter half of the 1990s were cyclically strong, EPA was concerned that business conditions during the 316(b) survey period (1996-1998) might be abnormally favorable for some of the five manufacturing sectors covered in the Phase III analysis. In this case, the business performance and valuation measures, which are based on survey data, used to assess the burden of regulatory compliance costs might overstate industry's ability to bear these costs and therefore understate the potential impact of the Phase III regulation.

- Second, apart from the issue of short-term deviation from trend caused by a cyclically strong economy, EPA was also aware from its profile analyses that some of the industries might be experiencing a longer-term trend of deteriorating performance. Using sample facility data that don't reflect such possible trends would again potentially overstate industry's ability to bear compliance costs and therefore understate the potential impact of the Phase III regulation.

Given these concerns, EPA analyzed for the manufacturing industries (1) whether business conditions were "abnormally favorable" during the survey period and (2) whether business performance over a longer term might be following a non-neutral – in particular, negative – trend. This analysis validated EPA's concerns that use of unadjusted survey data might yield erroneous conclusions from the facility impact analysis. From the findings of this analysis, EPA developed a basis for adjusting survey financial data to account for these effects: short-term deviation from trend and non-neutral trend.

This appendix documents EPA's analysis and development of adjustment factors for the 316(b) Phase III manufacturing industries.

B3A4-1 BACKGROUND: REVIEW OF OVERALL BUSINESS CONDITIONS

As background for its analysis, EPA reviewed general economic data over the past several years to assess whether business conditions during the survey data collection period of 1996-1998 might be generally perceived as abnormally favorable for the U.S. economy, as a whole. This review confirmed the concern that business conditions in 1996-1998 were generally more favorable than the average of conditions over a longer time period.

Figures B3A4.1-B3A4.3 present annual and average values for the period 1985-2003 for three measures of general economic performance:

Figure B3A4.1: Growth in Real Gross Domestic Product, 1985-2003. This exhibit, based on data published by the Department of Commerce, Bureau of Economic Analysis, focuses on the growth trend of the broad economy, including all sectors. Growth stronger than the average trend would indicate a strongly expanding economy and would generally indicate strong business performance.

Figure B3A4.2: Capacity Utilization in Manufacturing Industries, 1985-2003. This exhibit, based on U.S. Federal Reserve Bank data, reports the rate of capital utilization for all manufacturing sectors. All else equal, when the rate of capital utilization is higher than the average trend, demand for manufacturing output is strong and manufacturing business performance would be generally strong.

Figure B3A4.3: Growth in Industrial Production, 1985-2003. Like the preceding exhibit, this exhibit is based on data published by the U.S. Federal Reserve Bank and reports the rate of growth in the Federal Reserve's Industrial Production Index, which is a measure of the real output of the manufacturing industries. Growth stronger than the average trend would indicate a strong expansion in the manufacturing industries and would generally indicate strong manufacturing business performance.

In each case, the annual values in the period 1996-1998 are above the average trend line, indicating stronger overall economic performance in the survey data collection period than for the longer period presented in the charts. The data show a consistent year-by-year pattern over the 1996-1998 period:

- 1996: The values for 1996 are above the longer-term average trend but are the lowest of the values for the three years.

- 1997: The values for 1997 are the highest of the values for the three years.

- 1998: The values for 1998 fall between the 1996 and 1997 values. In the case of *industrial production* and *capacity utilization in manufacturing industries*, 1997 is the peak performance year over the 1990s decade and is followed by a decline in 1998 and subsequent years leading to the recession period in 2001. In the case of *GDP growth*, the fall-off in 1998 (from 1997) is followed by one more year of strong growth in 1999. Afterwards, GDP growth turns sharply lower during 2000, the recession year of 2001, and subsequent years. As is widely acknowledged in general business conditions analyses, economic weakness during the 2000-2003 period began earlier in the manufacturing industries than in the general economy.

Figure B3A4.1: Growth in Real Domestic Product, 1985-2003

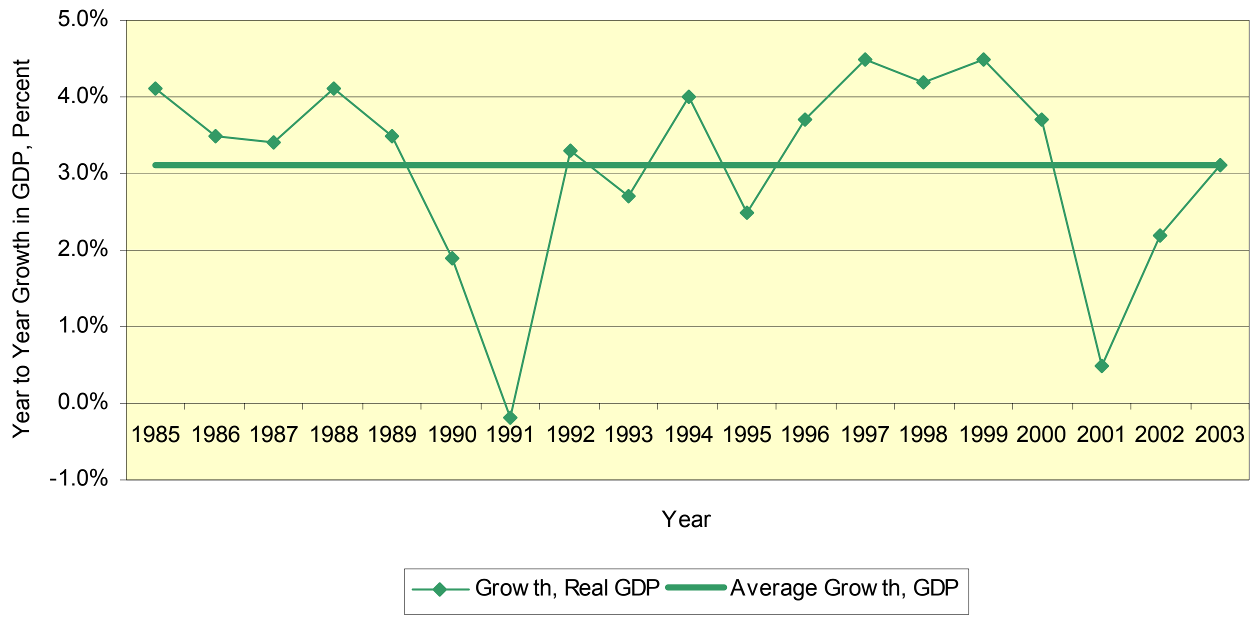


Figure B3A4.2: Capacity Utilization in Manufacturing Industries, 1985-2003

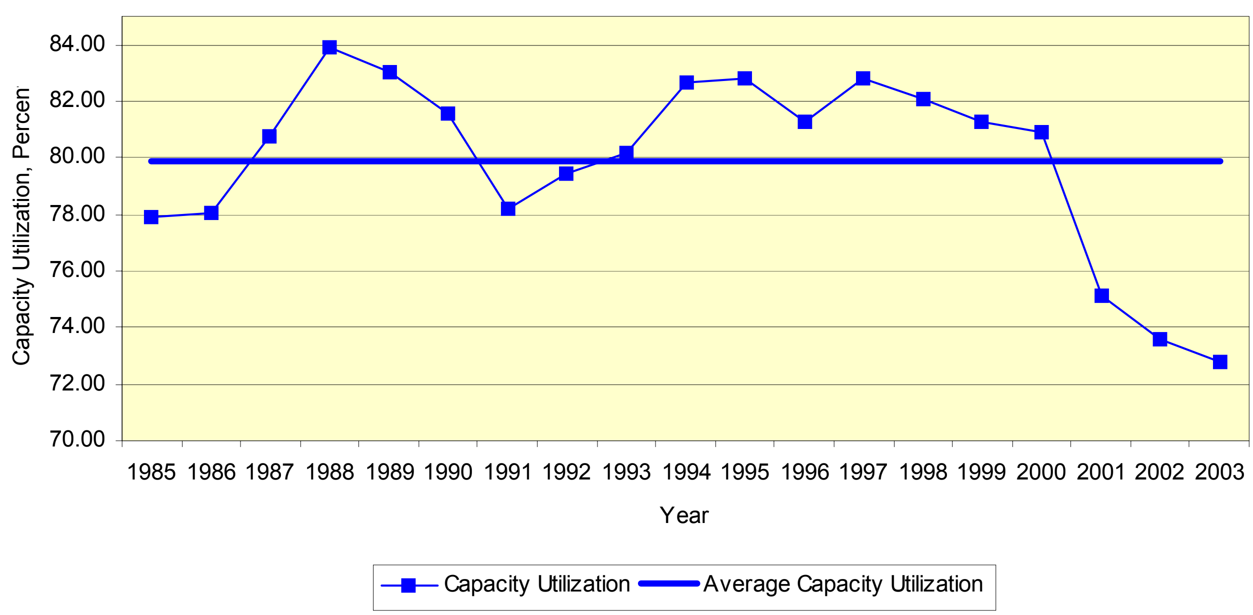
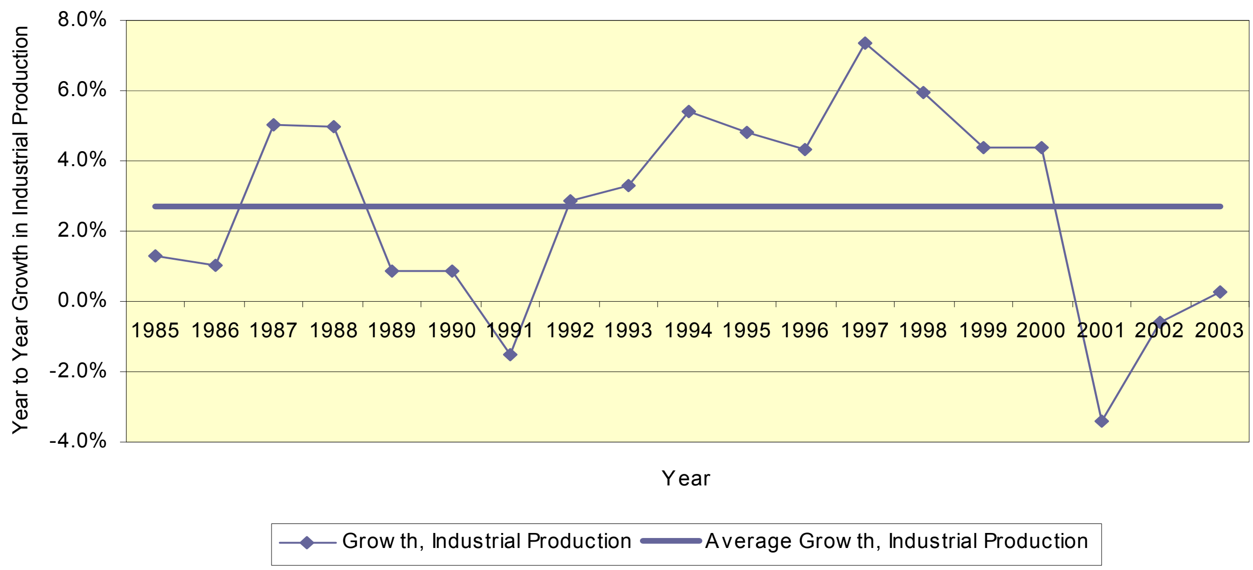


Figure B3A4.3: Growth in Industrial Production, 1985-2003



B3A4-2 Framing and Executing the Analysis

The objective of this analysis was to understand (1) the extent to which the business conditions and financial performance of the Phase III manufacturing industries reflected cyclically favorable conditions during the 316(b) survey period and (2) whether these industries show a non-neutral longer term trend in economic/financial performance – e.g., deterioration in performance over time independent of cyclical variation. If either or both of these conditions were found, then the data used to test for these conditions would be used to adjust relevant survey data items to a level consistent with normal business conditions and/or the longer term of performance.

To meet these objectives, EPA set, as its overall approach, identification and analysis of a financial performance data series for the 316(b) manufacturing industries. This data series would be used to test whether financial performance at the time of the 316(b) survey differed from the longer term trend. At the outset, EPA recognized that, in all likelihood, such a data series would not report financial performance at the level of the individual facility – which is the unit of analysis for the 316(b) facility impact analysis – but would report performance for individual firms or for some industry aggregate. As a result, EPA would need to infer the trend of performance in facility financial performance from firm- or industry-level performance and, in turn, apply adjustments, if needed, to facility financial data based on analysis of the firm- or industry-level performance. Although the use of firm- or industry-level information for adjusting facility data necessarily represents a limitation in this analysis, EPA judges that the effort is warranted given: (1) the potential for the facility impact analysis to yield erroneous findings if it is based on data that reflect cyclically favorable conditions and (2) the absence of facility data to support a more precise analysis.

Key steps in framing and executing the analysis are described below.

B3A4-2.1 Identifying the Financial Data Concept to Be Analyzed

EPA determined that the financial data concept to be analyzed should be equivalent, or close in concept, to the business performance and valuation metrics used in the Phase III impact analysis. For the facility impact analysis, the key financial metric is after-tax, pre-interest cash flow, calculated as income before interest, depreciation and amortization, and adjusted to be on an after-tax basis. In the facility impact analysis, this metric is used to calculate the business value of a sample facility, on both a baseline – i.e., before imposition of compliance costs – and post-compliance basis. Using this, or a closely related, measure in the analysis of financial performance at the time of the facility survey would therefore support a direct test of whether and how the survey financial data – *to be subsequently used in the facility impact analysis* – might reflect cyclically favorable conditions or differ from the longer term trend of financial performance in an analysis. If either or both of these conditions were found, the data would also readily support development of a necessary adjustment to offset these potential biases in the survey data.

EPA recognized that the after-tax, pre-interest cash flow measure used in the facility impact analysis would very likely not be directly available from financial datasets that might be practically used in this analysis. However, reasonable surrogates for this measure that would likely be available include: after-tax cash flow from operations (net income plus depreciation and amortization); earnings before interest, taxes, depreciation and amortization (EBITDA); net income; and earnings before interest and taxes (EBIT).

B3A4-2.2 Selecting Appropriate Data

Other key requirements of the data to be used in the analysis include:

- The financial data need to be a time series, preferably annual, over a sufficiently long period (and including the survey period) to allow testing of (1) whether survey period business conditions were cyclically favorable; and (2) whether financial performance in the industries exhibits a longer-term, non-neutral trend.

- The data need to be at a sufficient level of industry resolution to account for variations in business conditions and performance not only across the five manufacturing sectors but also *within* certain sectors, where there may be substantial variation in performance by important segments. Of particular importance is the ability to segment the chemicals sector into its segments such as basic chemicals and pharmaceuticals, and the primary metals sector into the ferrous and non-ferrous metals segments.

Based on these requirements, EPA selected the *Value Line Investment Survey* firm financial dataset as the data source for this analysis. The *Value Line* dataset meets analysis requirements as follows:

- The general company dataset of the Value Line Investment Survey (VL) reports summary financial information for nearly all publicly traded companies in the United States for a 12-year period, 1992-2003, which includes the 1996-1998 Phase III survey period. The individual years in this 12-year period may be categorized in three broad categories of economic performance: (1) six years of "normal" economic performance - 1992-1996 and 2000; (2) three years of "subnormal" economic performance - 2001-2003; and (3) three years of years of "supra-normal" economic performance - 1997-1999. The 12-year period thus captures reasonable diversity of business conditions before, after, and during the survey period. By including financial results for full-year 2003, the dataset also comes as close as possible to the present (2004) and thus would provide a basis for adjusting facility baseline financial data to essentially current conditions.

- VL identifies and groups companies in a business content classification scheme that approximates 3-digit SIC or 4-digit NAICS classifications. These business classifications support identification of firms within the Phase III manufacturing industries at a level of sector detail sufficient for this analysis. Because (1) the dataset is by company instead of by aggregate groups and (2) the business classifications are defined by practical business content instead of in a rigid SIC or NAICS classification scheme, the VL dataset avoids the challenge confronted elsewhere in the Phase III analysis of the change in economic classification schemes and resulting inconsistency of aggregated data series over the year of the change[1].

- The VL dataset reports key accounting items that will readily support calculation of a financial metric, after-tax cash flow, that very nearly matches the principal financial metric (after-tax, pre-interest cash flow) underlying the Phase III facility impact analysis.

EPA recognizes that the VL dataset, by definition, excludes firms that are not publicly traded. The studied industries include private, non-publicly traded firms, for which no comparable database of financial information is available. As a result, use of the VL dataset in this analysis could yield findings that are not representative of the overall industry, including the non-publicly traded firms, to the extent that non-public firms in the studied industries faced materially different business conditions or achieved materially different business performance than publicly traded firms in the same industries. Overall, EPA expects that the business conditions faced by, and performance achieved by, non-public firms in the studied industries are not likely to have been materially different from those of the public firms. As a result, EPA judges that use of the VL dataset for this analysis is appropriate and likely to yield reasonably representative findings for to overall industries, including publicly traded and non-traded firms.

In addition to the VL dataset, EPA considered a range of other data sources, including:

- Economic and business performance data published by the Federal Reserve, in particular the *Federal Reserve Economic Data* (*FRED II*) data series compiled by the Federal Reserve Bank of St. Louis.
- The *Quarterly Financial Report for Manufacturing, Mining, and Trade Corporations* (QFR) published by the U.S. Census Bureau.
- Data series from the Bureau of Economic Analysis and data specifically available in *The Survey of Current Business*.

These data sources were each deficient for the analysis in some material way, including:

- Data being too aggregate to provide the industry sector and sub-sector level of resolution needed to assess business conditions and trends within the Phase III manufacturing sectors.
- Data items being descriptive of general economic/financial conditions in an industry but not being sufficiently close to the financial performance concept needed for the analysis.
- Data being reported in inconsistent economic classification frameworks over the desired analysis period. In addition to the problem of the SIC/NAICS break itself, data are sometimes reported at different levels of resolution before and after the SIC/NAICS break – e.g., at a 4-digit or finer level in the NAICS framework but only 2-digit level of resolution in the SIC framework.
- Data not being readily available in an electronic format needed for efficient performance of the analysis.

B3A4-2.3 Selecting Industry Groups and Firms for Use in the Analysis

As discussed above, VL organizes firms by industry groups, which, in most instances, approximate 3-digit SIC or 4-digit NAICS classifications. From review of the VL industry groups and the 316(b) Phase III manufacturing industries, EPA selected 10 VL industry groups and the firms within these industry groups as candidates for this

[1] As described in the industry profiles, the change from SIC-based to NAICS-based reporting of economic data by federal government and other data sources at around 1997/98 created difficulties in aligning and ensuring consistency of time series data that are organized within these frameworks.

analysis. Following review of the firms within these industry groups, EPA retained 6 firms for use in this analysis. Key considerations in selecting the firms are as follows:

- The selected VL industry groups are those that most closely correspond to the 316(b) Phase III manufacturing industries.

- Within the industry groups, only those firms whose business operations reasonably match the profile of business activities of the 316(b) Phase III manufacturing industries were considered candidates for the analysis. In some industry groups, a substantial number of firms included in the VL industry groups were excluded from the analysis:

  - VL includes Aluminum industry firms in its Metals and Mining industry group. However, most firms in this VL industry group are not involved in the Aluminum industry and thus were excluded from the analysis dataset.

  - EPA retained from the Paper and Forest Products group only those firms engaged in pulp mill, paper mill and/or paper and paperboard manufacturing operations. Firms engaged only in timber and lumber production were excluded from the analysis.

- EPA retained only those firms that are based in the United States or Canada, and for which financial information is available in U.S. dollars.

- After defining an initial set of firms according to these procedures and criteria, EPA retained only those firms for which a full 12 years of data were available.

- Finally, EPA excluded firms that had undergone a significant restructuring – e.g., a merger or acquisition – which materially disrupted the continuity of financial reporting. Since the analysis to be performed would start from a time series of cash flow, measured in absolute dollars – as opposed, for example, to a time series of profit percentage values – including data from firms whose continuity of financial reporting had been affected by merger or acquisition activity would tend to bias the analysis. In particular, firms engaging in mergers and acquisitions that were accounted for on a purchase-accounting basis instead of a pooling-of-interests basis, would be likely to show sudden jumps in revenue, net income, and cash flow. These sudden jumps would bias the analysis by suggesting greater business growth than could be reasonably be achieved by the firm or facilities within the firm on a simple, organic growth basis. Similarly, large contractions in business volume resulting from divestiture or termination of a line of business would bias the analysis in the downward direction. To apply this restriction, EPA examined the year-to-year revenue profiles for all firms over the 12-year analysis period. EPA researched annual reports and other financial reporting for those firms showing large increases or decreases from year to year and excluded those firms where a material business event was found that would otherwise disrupt the continuity of financial reporting. *EPA followed this rule with only two exceptions. First, EPA kept firms in the analysis when the only business event/disruption of financial reporting occurred in the last year of financial reporting – 2003. EPA kept these firms in the analysis but excluded the final year of data from the analysis. Second, in its research on one firm in the paper industry, EPA found that the firm had recorded an unusual, non-recurring stock gain transaction in 1995 that caused revenue and net income to increase abnormally in that year. Although the VL net income item used in the analysis generally excluded income from unusual, non-recurring events, the VL data series did not exclude income from this transaction. Because EPA had already set aside a substantial number of firms from the paper industry, EPA decided to keep this firm in the analysis but exclude the single year of unusual financial performance from the analysis dataset*[2]. Applying this restriction substantially reduced the number of

[2] EPA considered removing the non-recurring item from the income statement but, because of uncertainty about the correct tax adjustment, rejected this approach.

firms that were included in the analysis dataset. In particular, for the Aluminum industry, all of the firms in the initial VL dataset were found to have some significant discontinuity of financial reporting.[3]

EPA organized these 60 firms into six 316(b) Industry Groups for the analysis. Table B3A4.1, below, lists the VL industry groups, the 316(b) Phase III manufacturing industries and/or industry segments (as discussed in the industry profiles) to which the VL industry groups approximately correspond, the 316(b) Industry Groups for this analysis, and the number of VL firms used in the analysis for each industry group.

Table B3A4.1: Value Line Industry Groups Selected for Analysis

Value Line Industry Group	316(b) Phase III Manufacturing Industry	316(b) Industry Segment(s) (as relevant)	316(b) Phase III Industry Group for Analysis	Number of Firms Used in Analysis
Metals and Mining	Aluminum		Aluminum	none
Paper and Forest Products	Pulp and Paper Mills		Pulp and Paper Mills	6
Chemical (basic)	Chemicals Industry	Organic Chemicals Inorganic Chemicals	Industrial Chemicals	15
Chemical (diversified)	Chemicals Industry	Organic Chemicals Inorganic Chemicals		
Chemical (specialty)	Chemicals Industry	Plastics Material and Resins	Plastics Material and Resins	15
Biotechnology	Chemicals Industry	Pharmaceuticals	Pharmaceuticals	4
Drug	Chemicals Industry	Pharmaceuticals		
Petroleum (integrated)	Petroleum Refining		Petroleum Refining	6
Steel (General)	Steel		Steel	14
Steel (Integrated)	Steel			

Source: Value Line Investment Survey and U.S. EPA analysis, 2004.

B3A4-2.4 Structuring the Analysis

The general objectives of this analysis were to:

- Test, by 316(b) Industry Group, whether after-tax cash flow performance deviated, during the 316(b) survey data collection years, from *normal* performance over the 12-year analysis period.

- Test, by 316(b) Industry Group, whether after-tax cash flow performance might be following a non-neutral trend over the 12-year analysis period.

[3] Because no Aluminum industry firms were able to be retained in the analysis, EPA was unable to develop an after-tax cash flow adjustment factor for facilities in the Aluminum industry. EPA considered adjusting the pre-event financial statements for the Aluminum industry firms – in effect, converting the purchase-accounting treatment of transactions to a pooling basis – but rejected this approach as requiring too many judgments. However, EPA assessed the potential effect of applying a cash flow adjustment factor to facilities in this industry by testing hypothetical factor values that substantially exceeded the adjustments – both for decrease and increase – estimated and applied for the facilities in other industries. This analysis found that the facility impact analysis results for the Aluminum industry did not change over this wide range of hypothesized cash flow adjustment factors.

- Given a finding that either or both of these conditions are true, to develop an adjustment to baseline after-tax cash flow to account for these effects, and, to yield after-tax cash flow values for the facility impact analysis that more closely reflect *current* financial performance in the 316(b) Phase III industries.

The overall approach to the analysis was to analyze, for each industry group, the trend of financial performance over the 12-year analysis period and to assess where the industry's financial performance lay relative to that trend during the 316(b) survey data collection years of 1996-1998. For each industry group. EPA used as analysis observations, an index of constant dollar-adjusted after-tax cash flow for each of the firms in the industry group. To analyze the trend, EPA calculated a simple regression of the index values against time. The estimated regression relationship provided a direct measure of the real (i.e., inflation-adjusted) trend of financial performance for each industry group. The 1996-1998 average of index values for each industry group were then compared with the trend values predicted from the estimated regression coefficients – both for the 1996-1998 years and for the end of the analysis period – to determine the extent to which 1996-1998 survey values should be adjusted to reflect (1) the deviation from trend at 1996-1998 and (2) the trend from 1996-1998 to the end of the analysis period.

Specific steps in this analysis were as follows:

- <u>Calculate After-Tax Cash Flow (ATCF) as Net Profit *plus* Depreciation for each firm by year</u>. As discussed above, EPA sought to analyze ATCF as a close approximation of the key financial metric – after-tax, pre-interest cash flow – used in the facility impact analysis. EPA calculated ATCF on a year-by-year basis for each firm in the analysis dataset as the sum of the VL data items: Net Profit and Depreciation. In the VL data framework, Net Profit is defined as net income from continuing operations and excluding non-recurring items. Depreciation includes both non-cash items, depreciation and amortization.

- <u>Adjust ATCF to constant dollar values at mid-year 2003, using the GDP deflator</u>. To eliminate the effects of inflation in analyzing the trend of financial performance, EPA deflated the ATCF values for all firms to mid-year 2003 using the GDP Deflator series published by the Department of Commerce, Bureau of Economic Analysis.

- <u>Calculate an index of each company's ATCF values by year using, as an index numerator, the average ATCF value for the company over the 12-year period</u>. As summarized above, the overall approach of the analysis involved a regression analysis of the trend of ATCF values for the firms in an industry group over the 12-year analysis period. To allow individual firms' ATCF values to be combined in a single regression requires eliminating the scale effect of the different sizes of firms. For this reason, the inflation-adjusted ATCF values for each firm were normalized to an index series by dividing the yearly values by the average of values for each firm over the 12-year period. EPA used the 12-year average of values for this index calculation instead of the value for a single year to prevent anomalously large swings in the index series when the ATCF value for the year selected as the base year for the index calculation was very small relative to other values in the 12-year series. In addition, in calculating the index values for the 12-year series, EPA first removed any negative values from the series for each firm by adding to each value in the firm's 12-year series, the absolute value of the most negative value for the firm plus the absolute value of the smallest non-negative value in the series. This adjustment has the effect of "vertically" shifting the ATCF values for a firm so that all values are positive while retaining the mathematical "shape" of the series for the trend analysis. This adjustment was necessary to prevent the undesirable inversion of the index trend that would occur if a negative index numerator is combined with a positive series values in calculating the index series.

- <u>Regress ATCF index values against year by industry group to calculate the time trend of constant dollar ATCF over the period 1992-2003</u>. The preceding calculations yield a constant dollar series of ATCF indexed to one and with an average value of one over the 12-year analysis period. To calculate the trend indicated by these index ATCF values, EPA estimated a weighted linear regression of the index ATCF values against year by industry group. These regressions were performed on a revenue-weighted basis –

i.e., each ATCF value was weighted by the firm's revenue value for the year – so that each firm's *individual* ATCF trend carries a weight in proportion to its revenue in estimating the trend relationship. As a result, the estimated trend relationship reflects a revenue-weighted average of the ATCF trends of the individual firms, instead of an arithmetic average, which would overweight the presence of smaller firms in estimating the trend relationship. The estimated ATCF index coefficient from the regression for each industry indicates the trend in constant dollar ATCF over the analysis period: a negative coefficient indicates declining constant dollar ATCF over the analysis period; a positive coefficient indicates growing constant dollar ATCF over the analysis period.[4]

- <u>Calculate the predicted trend of ATCF index values for each industry group</u>. Used together, the estimated ATCF index coefficient and regression intercept yield a predicted trend line of ATCF index values for the 12-year period , for each industry group analyzed. The actual ATCF index values for an industry group can then be compared with *predicted* trend line to assess whether the ATCF values during the 1996-1998 survey data collection period deviate from the trend. The predicted trend line also indicates *where* the ATCF index values would be at the end of the analysis period if the ATCF index values followed the predicted trend.

- <u>Calculate the revenue-weighted average of *actual* ATCF index values by industry group for the 1996-1998 period</u>. The revenue-weighted average of actual ATCF values for the 1996-1998 period is compared with the predicted trend values to assess the extent to which the actual ATCF index values deviate from trend and to provide a basis for estimating the adjustment needed to bring the ATCF values to the trend, or to the predicted trend value at the end of the analysis period. These values were calculated by, first, averaging the 1996, 1997, and 1998 ATCF index values for each firm, and, second, averaging these firm-average values over the firms in an industry group using, as weights, the 1996-1998 average revenue of each firm in the industry group.

B3A4-3 SUMMARY OF FINDINGS

Table B3A4.2, below, summarizes key results from the analyses outlined above. Items reported in the table are as follows:

- <u>Estimated Trend</u>: the revenue-weighted average of annual change in ATCF Index values for firms in the industry group over the analysis period, 1992-2003. This value is the estimated coefficient of ATCF Index against time from the simple linear regression, as described above. Because the trend is estimated from an index series with an average value of one over the analysis period, the estimated trend may also be interpreted as equal approximately to the annual percent change in ATCF Index. A negative estimated trend value indicates that ATCF Index values decline, on average, over the analysis period; a positive estimated trend value indicates that ATCF Index values increase, on average, over the analysis period.

- <u>Average of ATCF Index Values at 1996-1998</u>: the revenue-weighted average of *actual* ATCF Index values for firms in the industry analysis set over the 1996-1998 period. The values in this column are compared with values in the next two columns, respectively, to assess (1) the extent to which financial performance during the 1996-1998 survey data period deviated from the analysis period trend *at 1996-1998* and (2) the overall change in financial performance from the 1996-1998 survey data period to the end of the analysis period resulting from the combination of deviation from analysis period trend and the trend, itself (see following paragraphs for further discussion).

- <u>Average of Predicted Trend Values at 1996-1998</u>: the average of *predicted* ATCF Index values over the 1996-1998 survey data period *as predicted from the estimated regression terms*. If ATCF performance for an individual firm or industry matched the industry trend over time, the actual ATCF Index values at

[4] In addition to testing a simple linear model of index ATCF against time, EPA also used a logarithm-adjusted series of the ATCF values to test for an exponential trend in ATCF. The log model provided no improvement in the estimated regression relationships. As a result, EPA used the coefficients estimated from the linear model for its analysis of the ATCF trend.

1996-1998 *would* equal this value. Material deviation of the *actual* ATCF Index values from this value suggests, for an industry, that ATCF performance during the 1996-1998 survey data period was: (1) abnormally favorable, if the *actual* ATCF Index values exceed the average of predicted values, or (2) abnormally unfavorable, if the *actual* ATCF Index values are less than the average of predicted values.

- Predicted Trend Value at 2003: the ATCF Index value at the end of the analysis period *as predicted from the estimated regression terms*. This value is the (statistically) expected value of ATCF Index at 2003 for a firm or for the industry, based on the estimated trend relationship. Material deviation of this value from the Average of Predicted Trend Values at 1996-1998 indicates a general trend going forward from the 1996-1998 survey data period, which, apart from cyclical deviation, which would further affect ATCF performance for firms in the industry group. For an industry, if this value is *less than* the Average of Predicted Trend Values at 1996-1998, then financial performance, as indicated by ATCF Index, generally deteriorated from 1996-1998 forward to 2003, the end of the analysis period. In addition to the cyclical deviation effect, this "trend" effect might also be taken into account in adjusting ATCF data calculated from the 316(b) survey responses. In this case, comparison of the average of *actual* ATCF Index values over the 1996-1998 survey data period with the Predicted Trend Value at 2003, would indicate the total potential adjustment, accounting for both the cyclical deviation and trend effects.

Table B3A4.2: Key Results from Analysis of After-Tax Cash Flow Trends by 316(b) Industry for 1992-2003

316(b) Phase III Industry Group	Estimated Trend	Average of ATCF Index Values at 1996-1998	Average of Predicted Trend Values at 1996-1998	Predicted Trend Value at 2003
Aluminum	Analysis not undertaken for the Aluminum industry			
Pulp and Paper Mills	-0.00040	0.98953	1.03058	1.02880
Industrial Chemicals	0.00120	1.10059	1.00837	1.01567
Plastics Material and Resins	0.03180	1.03865	0.99332	1.18383
Pharmaceuticals	0.05070	0.98775	0.99703	1.30096
Petroleum Refining	0.02300	0.92346	1.01441	1.15248
Steel	-0.00420	1.25879	1.03948	1.01414

Source: U.S. EPA analysis, 2004.

The following page presents charts, by industry group, of the yearly ATCF Index Values and the estimated predicted trend values over the analysis period.

Figure B3A4-4: ATCF Index vs Trend

By industry, these results indicate the following:

- Pulp and Paper Mills. The analysis indicates a very slight annual decline, approximately -0.04 percent, in constant dollar ATCF over the analysis period, meaning financial performance declined very modestly over this period. The analysis also indicates that the survey data collection years of 1996-1998 showed weaker performance than the predicted trend performance in those years. Specifically, the average actual ATCF index value at 1996-98 is 4.0 percent below the predicted ACTF trend value for those years. With negative growth in ATCF over the analysis period, the predicted ATCF index value at the end of the analysis period, 2003, declines slightly from the 1996-1998 period. As a result, the average actual ATCF index value at 1996-98 is approximately 3.8 percent below the predicted ACTF trend value in 2003.

- Industrial Chemicals. The analysis for the Industrial Chemicals segment of the Chemicals industry indicates a very slight annual increase, approximately 0.12 percent, in constant dollar ATCF over the analysis period, meaning financial performance improved slightly over this period. In contrast to the finding for the Paper and Allied Products industry, the analysis indicates that the Industry Chemicals segment achieved higher financial performance during the survey data collection years of 1996-1998 than the predicted trend performance in those years. Specifically, the average actual ATCF index value at 1996-98 is 9.1 percent above the predicted ACTF trend value for those years. With slight positive growth in ATCF over the analysis period, the predicted ATCF index value at the end of the analysis period, 2003, increase slightly from the 1996-1998 period. As a result, the average actual ATCF index value at 1996-98 is approximately 8.4 percent above the predicted ACTF trend value in 2003.

- Plastics Material and Resins. This segment of the Chemicals industry shows a moderate increase, 3.2 percent annually, in constant dollar ATCF over the analysis period. From this analysis, the Plastic Material and Resins segment, like the Industrial Chemicals segment, also achieved higher financial performance during the survey data collection years of 1996-1998 than the predicted trend performance in those years. Specifically, the average actual ATCF index value at 1996-98 is 4.6 percent above the predicted ACTF trend value for those years. However, with relatively strong positive growth in ATCF, the predicted ATCF index value at the end of the analysis period, 2003, increases sufficiently to reverse this relationship. As a result, by 2003, the average actual ATCF index value at 1996-98 is 12.3 percent *below* the predicted ACTF trend value in 2003.

- Pharmaceuticals. This third segment of the Chemicals industry also shows a strong increase, 5.1 percent annually, in constant dollar ATCF over the analysis period. Financial performance during the survey data collection years very nearly equaled the predicted ATCF index value: the average ATCF index value at 1996-98 is 0.9 percent below the predicted ACTF trend value for those years. With strong growth in ATCF over the analysis period, by 2003, the predicted ATCF value is substantially higher than the average ATCF index value at 1996-98: the average ATCF index value at 1996-1998 is 24.1 percent below the predicted trend value at 2003.

- Petroleum Refining. The analysis indicates a moderate increase, 2.3 percent annually, in constant dollar ATCF over the analysis period. The analysis also indicates that the Petroleum Refining industry achieved, on average, weaker financial performance during the survey data collection years than the predicted trend performance in those years: the average ATCF index value for 1996-1998 is 9.0 percent below the predicted trend value during those years. However, the individual yearly values during 1996-1998 show considerable volatility relative to the trend, suggesting weak confidence in this finding. Like Pharmaceuticals, with relatively strong growth in ATCF over the analysis period, by 2003, the predicted ATCF value is substantially higher than the average ATCF index value at 1996-98: the average ATCF index value at 1996-1998 is 19.9 percent below the predicted trend value at 2003.

- Steel. The analysis indicates declining performance, approximately -0.4 percent annually, in constant dollar ATCF over the analysis period. The analysis also indicates that financial performance during the survey data collection years substantially exceeded, by 21.1 percent, trend-based predicted performance during those years. With declining trend-based performance through the end of the analysis period, by

2003, the gap between the average ATCF value at 1996-1998 and the predicted trend value at 2003 widens to 24.1 percent.

Table B3A4.3, below, summarizes these findings.

Table B3A4.3: Estimated Relationship Between Actual ATCF at Survey Period and Trend Predicted Values at Survey Period and End of Analysis Period

316(b) Phase III Industry Group	Percentage Difference in Actual and Predicted ATCF Index Values at 1996-1998	Percentage Difference in Actual ATCF Index Values at 1996-1998 and Trend Predicted Value at 2003
Aluminum	Analysis not undertaken for the Aluminum industry	
Pulp and Paper Mills	-4.0%	-3.8%
Industrial Chemicals	9.1%	8.4%
Plastics Material and Resins	4.6%	-12.3%
Pharmaceuticals	-0.9%	-24.1%
Petroleum Refining	-9.0%	-19.9%
Steel	21.1%	24.1%

Source: U.S. EPA analysis, 2004.

From these results, the industries and/or segments where financial performance during the 1996-1998 survey data collection period exceeds trend-predicted performance and thus for which survey data may overstate the industry's ability to withstand compliance burdens *in comparison to the predicted trend values at 1996-1998* are:

- Pulp and Paper Mills industry,
- Industrial Chemicals segment of the Chemicals industry,
- Plastics Material and Resins segment of the Chemicals industry , and
- Steel industry.

Looking to the end of the analysis period, 2003, the industries and/or segments where financial performance during the 1996-1998 survey data collection period exceeds trend-predicted performance at 2003, and thus for which survey data may overstate the industry's ability to withstand compliance burdens at a time closer to the point of regulatory implementation are:

- Industrial Chemicals segment of the Chemicals industry, and
- Steel industry.

B3A4-4 DEVELOPING AN ADJUSTMENT CONCEPT

On the basis of these findings, EPA considered whether and how to adjust after-tax cash flow, as derived from the facility survey responses for use in the facility impact analysis. Given that several of the industries, or segments within industries, were found to have financial performance during the survey data collection period that exceeded the predicted trend financial performance for that period or that exceeded the predicted trend financial performance at the end of the analysis period, EPA concluded that development and application of an adjustment to baseline after-tax cash flow was warranted.

In deciding how to adjust cash flow, EPA considered three primary adjustment concepts:

1. Adjust baseline cash flow to account for deviation from predicted trend at the time of the survey data collection.

2. Adjust baseline cash flow to account for deviation from predicted trend at the end of the analysis period.

3. Adjust baseline cash flow to a future estimated period of compliance based on the estimated trend of change in constant dollar after-tax cash flow over time.

EPA decided to apply the ATCF adjustment according to the second of these three adjustment concepts: Adjust baseline cash flow to account for deviation from predicted trend at the end of the analysis period. This adjustment concept addresses both concerns that (1) business performance during the survey data collection period diverged from the predicted trend performance during the survey data collection period, and (2) business performance from the time of survey data collection period followed a non-neutral trend to the present. EPA considered extending the trend projection to the estimated time of compliance (concept 3) but rejected this approach since it was deemed speculative in attempting to forecast business performance into the future. In addition, the greater the number of years over which ATCF results are projected based on historical trend, the less likely that the predicted changes in ATCF reflect the performance of a static set of facilities and instead reflect capital additions, new facilities, facility closures, etc. For these reasons, EPA decided to restrict the adjustment to the end of the ATCF analysis period.

EPA also considered whether to apply the indicated adjustment factors *asymmetrically* – i.e., only to reduce the ATCF values as calculated from facility survey responses – or *symmetrically* – i.e., both to increase or to reduce the ATCF values as calculated from facility survey responses. In the case of asymmetric adjustment, the adjustment would correct for business performance during the survey data collection period that exceeded the predicted trend value – whether for the survey period or some future period – and would thus attempt to avoid overstating the a facility's ability to bear the costs of regulation compliance without material financial impact. In the case of a symmetric adjustment, the adjustment would additionally address the potential that business performance during the survey data collection period fell short of the predicted trend value and would thus attempt to avoid understating the ability of an industry or facility to bear the costs of regulatory compliance without material financial impact.

On this question, EPA decided to apply the ATCF adjustment on a symmetric basis, potentially reducing or increasing facility cash flow on the basis of the estimated adjustment factor. EPA based its decision on the principle of avoiding both overstatement and understatement of the ability of facilities in an industry to bear the costs of regulatory compliance without material financial impact.

Based on these decisions, EPA calculated the adjustment factors by dividing the *Predicted Trend Value at 2003* by the *Average of ATCF Index Values at 1996-1998*, as reported in Table B3A4-2, above. In the facility closure analysis, as described in *Chapter B3: Economic Impact Analysis for Manufacturers*, facility after-tax cash flow is simply multiplied by the appropriate adjustment factor based on the industry or industry segment to which a facility is assigned. The resulting adjusted ATCF is carried forward in the baseline and post-compliance closure analyses. Where the *Predicted Trend Value at 2003* is less than *Average of ATCF Index Values at 1996-1998*, the resulting adjustment factor value is less than one and the effect of the ATCF adjustment is to reduce the calculated value of cash flow used in the facility impact analysis. Where the *Predicted Trend Value at 2003* is greater than *Average of ATCF Index Values at 1996-1998*, the resulting adjustment factor value is greater than one and the effect of the ATCF adjustment is to increase the calculated value of cash flow used in the facility impact analysis.

EPA also used the adjustment factors to adjust the numerator values of the measures used in the facility moderate impact analysis: pre-tax return on assets and interest coverage ratio. In both cases, the numerators of the measures are closely related to cash flow, but are calculated on a pre-tax basis. As a result, in this case, the ATCF-based adjustment factor does not match as closely in concept the financial measures to which it is applied as is the case for the ATCF measure used in the facility closure analysis. Nevertheless, use of the adjustment for these measures is appropriate because the pre-tax measures used in the facility moderate impact analysis will still move closely with the after-tax cash flow measure on which the adjustment factor is based. In addition, it is important that EPA recognize the potential effect of change in financial condition since the survey data collection period in the facility moderate impact analysis as well as in the facility closure analysis.

Table B3A4.4, below, summarizes the adjustment factors implemented for each of the industries, and within the chemical industry, for the industry segments. The table also reports the number of baseline and post-compliance closures (under the proposed regulatory option) estimated with and without application of the ATCF adjustment factor.

Table B3A4.4: Using After-Tax Cash Flow Adjustment Factors in the Facility Closure Analysis

	Adjustment Factor	Number of Facilities Analyzed	Summary Results from Closure Analysis: Using Adjustment Factors		Summary Results from Closure Analysis: Not Using Factors	
			Baseline Closures	Regulatory Closures	Baseline Closures	Regulatory Closures
Aluminum	*1.0000*	21	*7*	*0*	7	0
Pulp and Paper Mills	1.0397	230	32	0	32	0
Chemicals Industry						
Industrial Chemicals	0.9228	138	4	0	4	0
Plastics Material and Resins	1.1398	34	0	0	0	0
Pharmaceuticals	1.3171	6	0	0	0	0
Petroleum Refining	1.2480	36	5	0	5	1
Steel	0.8056	68	29	0	25	0
Total		**532**	**76**	**0**	**73**	**1**

Adjustment factor not developed for Aluminum industry, so the results with use of adjustment factors are necessarily the same as those without use of the factors.

All results are sample weighted. The reported totals may differ from the apparent sums of individual data items due to rounding.

Source: U.S. EPA analysis, 2004.

As reported in Table B3A4.4, the adjustment factors for the Steel industry and Industrial Chemicals segment of the Chemicals industry are less than one, at 0.8056 and 0.9228, respectively. For these industries, the effect of the adjustment factor is to reduce the cash flow values calculated from facility survey responses. As described above, EPA did not calculate an adjustment factor for the Aluminum industry due to data limitations; accordingly, this industry's "adjustment factor" is simply 1.0000. The adjustment factors for the remaining industries are greater than one, ranging from a value of 1.0397 for the Pulp and Paper Mills industry to 1.3198 for the Pharmaceuticals segment of the Chemicals industry. For these industries, the effect of the adjustment factor is to increase the cash flow values calculated from facility survey responses.

In terms of effect on analytic results, the use of the ATCF adjustment factors caused the number of baseline closures to change in only one 316(b) industry group, the Steel industry. For this industry, the reduction in cash flow resulting from the adjustment causes an additional 4 facilities, on a sample weighted basis, to fail the baseline closure analysis.

Under the 50 MGD All Option for existing manufacturing facilities, the use of the ATCF adjustment factors eliminated one regulatory closure, in the Petroleum Refining industry. Because the calculated adjustment factor for this industry is quite large, 1.248, EPA reviewed closely the effect of the adjustment factor on the facility closure calculation. In particular, EPA was concerned that the regulatory closure was being eliminated by application of a large ATCF adjustment. From this review, EPA determined that the single Petroleum Refining industry closure, *without the ATCF adjustment*, is a very marginal closure. Specifically, an ATCF adjustment factor of 1.0195 (compared to the calculated 1.248) provides a sufficient increase in baseline cash flow to eliminate the closure under the compliance requirements of the 50 MGD All Option. Another way of understanding the 1.0195 adjustment factor is to calculate the annual trend factor (year-to-year change in predicted trend ATCF Index) that would yield the 1.0195 value. In this case, the year-to-year change required to generate the 1.0195 value is 0.0038, or an annual change factor that is very close to zero (approximately 0.38 percent annual average change). Given these findings, EPA concludes that the extent of improvement in cash flow needed to eliminate the regulatory closure in the Petroleum Refining industry is extremely small and is thus quite plausible within the overall improving business performance trend exhibited by the Petroleum Refining industry. Under the other two co-proposed options, the 200 MGD All Option and the 100 MGD SWB Option, the use of the ATCF adjustment factors would have no closure effect.

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Appendix 5 to Chapter B3: Estimating Capital Outlays for Section 316(b) Phase III Manufacturing Sectors Discounted Cash Flow Analyses

INTRODUCTION

APPENDIX CONTENTS

The analysis of economic impacts to Phase III manufacturing facilities associated with the proposed Section 316(b) Regulation involves calculation of the business value of sample facilities on the basis of a discounted cash flow (DCF) analysis of operating cash flow as reported in the detailed industry questionnaires.[1] Business value is calculated on a pre- and post-compliance basis and the change in this value serves as an important factor in estimating regulatory impacts in terms of potential facility closures. To be accurate in concept, the business value calculation should recognize cash outlays for capital acquisition as a component of cash flow. However, the Section 316(b) Detailed Industry Questionnaire did not request information from surveyed facilities on their cash outlays for capital acquisition. Absent this data, EPA developed an estimate of cash outlays for capital acquisition. This appendix describes the methodology EPA used to derive, for each sample facility, an estimate of cash outlays for capital acquisition.

EPA Office of Water (OW) previously identified that the omission of cash outlays for capital acquisition from DCF analyses may lead to overstatement of the business value of sample facilities and, as a consequence, understatement of regulatory impacts in terms of estimated facility closures (EPA, 2003). In response to this omission, the Office of Management and Budget suggested the adoption of depreciation expense as a surrogate for cash outlays for capital replacement and additions. However, for several reasons EPA believes depreciation is a poor surrogate. First, depreciation is meant to capture the consumption/use of previously acquired assets, *not* the cost of replacing, or adding to, the existing capital base. Therefore, depreciation is fundamentally the wrong concept to use as a surrogate for capital outlays for capital replacement and additions. Second, depreciation is estimated based on the historical asset cost, which may understate or overstate the real replacement cost of assets. Third, both book and tax depreciation schedules generally understate the assets' useful life. Thus, reported depreciation will overstate real depreciation value for recently acquired assets that are still in the depreciable asset base, and conversely, understate the real depreciation value of assets that have expired from the depreciable asset base but still remain in valuable use. Finally, depreciation does not capture the important variations in capital outlays that result from differences in revenue growth and financial performance among firms. Businesses with real growth in revenue will need to expand both their fixed and working capital assets to support business growth, and all else being equal, growing businesses will have higher ongoing outlays for fixed and working capital assets. Similarly, the ability of businesses to renew and expand their asset base depends on the financial productivity of the deployed capital as indicated by measures such as return on assets or return on invested capital. As a result, businesses with "strong" asset productivity will attract capital for renewal and expansion of their asset base, while businesses with "weak" asset productivity will have difficulty attracting the capital for renewal and expansion of the business' asset base. All else being equal, businesses with strong asset productivity

[1] This analysis is limited to potentially affected facilities in primary SIC codes 26, 28, 29, and 33.

will have higher ongoing outlays for capital assets; businesses with weak asset productivity will have lower ongoing outlays for capital assets.

As an approach to addressing the absence of capital acquisition cash outlay data to support the Phase III DCF analysis, EPA estimated a regression model of capital outlays using reported capital expenditures and relevant explanatory financial and business environment information for public-reporting firms in the Phase III manufacturing sectors. The resulting estimated model is used to estimate capital outlays for facilities in the Phase III sample dataset. The estimated capital outlay values were then used in the DCF analyses to calculate business value of sample facilities and estimate regulatory impacts in terms of facility closures.

The approach and regression model described above are based largely on the approach and regression model developed in support of the analysis of economic impacts for the Metal Products and Machinery Regulation (MP&M), which provides a recent example of the need to address the omission of capital acquisition cash outlay data from a DCF analysis. EPA notes that the facilities/industry sectors examined in the Section 316(b) Phase III analysis are similar to those analyzed in the MP&M analysis: both analyses estimate impacts to facilities in manufacturing industries only and facilities in SIC 33 are covered under both regulations. In addition, the Section 316(b) Detailed Industry Questionnaire and the MP&M survey instruments are similar; therefore, similar data are available for Phase III and MP&M survey facilities. As such, EPA relied heavily on prior experience from the MP&M final regulation in estimating the regression model used to estimate of capital outlays for facilities in the Phase III sample dataset.

This appendix reports the results of the effort to estimate capital outlays for Phase III manufacturing facilities, including: an overview of the analytic concepts underlying the analysis of capital outlays; specific variables included in the regression analysis; summary of data selection and preparation; general specification of regression models to be tested; and the findings from the regression analyses.[2]

B3A5-1 ANALYTIC CONCEPTS UNDERLYING ANALYSIS OF CAPITAL OUTLAYS

On the basis of general economic and financial concepts of investment behavior, EPA began its analysis by outlining a framework relating the level of a firm's capital outlays to explanatory factors that:

- can be observed for public-reporting firms – either as firm-specific information or general business environment information – and thus be included in a regression analysis; and
- for firm-specific information, are also available from the Phase III sample facility dataset.

To aid in identifying the explanatory concepts and variables that might be used in the analysis and as well in specifying the models for analysis, EPA reviewed recent studies of the determinants of capital outlays. EPA's review of this literature generally confirmed the overall approach in seeking to estimate capital outlays and helped to identify additional specific variables that other analysts found to contribute important information in the analysis of capital outlays (e.g., the decision to test capacity utilization as an explanatory variable, see below, resulted from the literature review). Articles reviewed are listed in Attachment B3A5A to this appendiB3A5

Table B3A5.1, beginning below and continuing on the subsequent page, summarizes the conceptual relationships between a firm's capital outlays and explanatory factors that EPA sought to capture in this analysis. In the table, EPA outlines the concept of influence on capital outlays, the general explanatory variable(s) that EPA identified

[2] Since the estimated regression model for the Phase III facilities is based on an earlier model developed for the MP&M final regulation, much of the underlying research involved in the analytic development of the model had been previously completed and was not required to be redone. Nonetheless, in order to present a lucid discussion of the analytic concepts underlying the model and the rationale behind specifying variables for the analysis and specification of the regression model, a complete discussion of how the regression model was developed is presented. During the course of the discussion, instances where prior experience gained during estimating the regression model for the MP&M final regulation had a significant influence in the development of the current model are clearly highlighted.

to capture the concept in a regression analysis, and the hypothesized mathematical relationship (sign of estimated coefficients) between the concept and capital outlays. Table B3A52 identifies the specific variables included in the analysis, including any needed manipulations and the correspondence of the variables to Phase III survey information.

Table B3A5.1: Summary of Factors Influencing Capital Outlays

Explanatory Factor/Concept To Be Captured in Analysis	Translation of Concept to Explanatory Variable(s)	Expected Relationship
Availability of attractive opportunities for additional capital investment. A firm's owners, or management acting on behalf of owners, should expend cash for capital outlays only to the extent that the expected return on the capital outlays – whether for replacement of, or additions to, existing capital stock – are sufficient to compensate providers of capital for the expected return on alternative, competing investment opportunities, taking into account the risk of investment opportunities.	Historical ***Return On Assets*** of establishment as a indicator of investment opportunities and management effectiveness, and, hence, of desirability to expand capital stock and ability to attract capital investment. Use of a historical variable implicitly assumes past performance is indicative of future expectations.	Positive
Business growth and outlook as a determinant of need for capital expansion and attractiveness of investment opportunities. All else equal, a firm is more likely to have attractive investment opportunities and need to expand its capital base if the business is growing and the outlook for business performance is favorable.	***Revenue Growth***, from the prior time period(s) to the present, provides a *historical* measure of business growth and is a potential indicator of need for capital expansion. Use of a historical variable implicitly assumes past performance is indicative of future expectations.	Positive
	Clearly, the theoretical preference is for a forward-looking indicator of business growth and need for capital expansion. Options EPA identified include ***Index of Leading Indicators*** and current ***Capacity Utilization***, by industry. Higher current *Capacity Utilization* may presage need for capital expansion.	Positive
Importance of capital in business production. All else equal, the more capital intensive the production activities of a business, the greater will be the need for capital outlay to replenish, and add to, the existing capital stock. More capital intensive businesses will spend more in capital outlays to sustain a given level of revenue over time.	The ***Capital Intensity*** of production as measured by the production capital required to produce a dollar of revenue provides an indicator of the level of capital outlay needed to sustain and grow production. As an alternative to a firm-specific concept such as Capital Intensity of production, differences in business characteristics might be captured by an ***Industry Classification*** variable.	Positive
Life of capital equipment in the business. All else equal, the shorter the useful life of the capital equipment in a business, the greater will be the need for capital outlay to replenish, and add to, the existing capital stock.	No information is available on the actual useful life of capital equipment by business or industry classification. However, the ***Capital Turnover Rate***, as calculated by the ratio of book depreciation to net capital assets, provides an indicator of the rate at which capital is depleted, according to book accounting principles: the higher the turnover rate, the shorter the life of the capital equipment. However, the measure is imperfect for reasons of both the inaccuracies of book reporting as a measure of useful life, and as well the confounding effects of growth in the asset base due to business expansion – which will tend to lower the indicated turnover rate, all else equal, without a real reduction in life of capital equipment. As above, an alternative to a firm-specific concept, differences in business characteristics might be captured by an ***Industry Classification*** variable.	Positive, generally, but with recognition of the potential for counter-trend effects

Table B3A5.1: Summary of Factors Influencing Capital Outlays

Explanatory Factor/Concept To Be Captured in Analysis	Translation of Concept to Explanatory Variable(s)	Expected Relationship
The cost of financial capital. The cost at which capital – both debt and equity – is made available to a firm will determine which investment opportunities can be expected to generate sufficient return to warrant use of the financial capital for equipment purchases. All else equal, the higher the cost of financial capital, the fewer the investment/capital outlay opportunities that would be expected to be profitable and the lower the level of outlays for replacement of, or additions to, capital stock.	Preferably, measures of cost-of-capital would be developed separately for debt and equity. The ***Cost of Debt Capital***, as measured by an appropriate benchmark interest rate, provides an indication of the terms of debt availability and how those terms are changing over time. Preferably, the debt cost/terms would reflect the credit condition of the firm, which could be based on a credit safety rating (e.g., S&P Debt Rating).	Negative
	The cost of equity capital is more problematic than the cost of debt capital since it is not directly observable for either public-reporting firms or, in particular, private firms in the Phase III dataset. However, a readily available surrogate such as ***Market-to-Book Ratio*** provides insight into the terms at which capital markets are providing equity capital to *public-reporting firms*: the higher the Market-to-Book Ratio, the more favorable the terms of equity availability.	Negative
The price of capital equipment. The price of capital equipment – in particular, how capital equipment prices are changing over time – will influence the expected return from capital outlays. All else equal, when capital equipment prices are increasing, the expected return from incremental capital outlays will decline and vice versa. However, although the generally expected effect of higher capital equipment prices is to remove certain investment opportunities from consideration, the potential effect on *total capital outlay* may be mixed. If expected returns are such that the demand to invest in capital projects is relatively inelastic, the effect of higher prices for capital equipment may be to raise, instead of lower, the total capital outlay for a firm.	Index provides an indicator of the change in capital equipment prices.	Negative, generally, but with recognition of the potential for counter-trend effects

Source: U.S. EPA analysis, 2004.

B3A5-2 SPECIFYING VARIABLES FOR THE ANALYSIS

Working from the general concepts of explanatory variables outlined above, EPA defined the specific explanatory variables to be included in the analysis. A key requirement of the regression analysis is that the firm-specific explanatory variables included in the regression analysis later be able to be used as the basis for estimating capital expenditures for facilities in the Phase III dataset. As a result, in defining the firm-specific variables, it was necessary to ensure that the definition of variables selected for the regression analysis using data on public-reporting firms be consistent with the data items available for facilities in the Phase III dataset.

Also, EPA's selection of firm-specific variables was further constrained by the decision to use the Value Line Investment Survey (VL) as the source of firm-specific information for the regression analysis. The decision to use VL as the source of firm-specific data for the analysis was driven by several considerations:

- *Reasonable breadth of public-reporting firm coverage.* The VL dataset includes 8,500 firms.
- *Reasonable breadth of temporal coverage.* VL provides data for the most recent 11 years – i.e., 1992-2002. Although ideally EPA would have preferred a longer time series to include more years

not in the "boom" business investment period of the mid- to late-1990s.

- *Reasonable coverage of concepts/data needed for analysis.* The VL data includes a wide range of financial data that are applicable to the analysis (VL provides 37 data items over the 11 reporting years; see Attachment DB). However, because of the pre-packaged nature of the VL data, it was not possible to customize any data items to support more precise definition of variables in the analysis. In particular, EPA found that certain balance sheet items were not reported to the level of specificity preferred for the analysis. Overall, though, EPA expects the consequence of using more aggregate, less-refined concepts should be minor.

The decision to use VL data for the analysis constrained, in some instances, EPA's choice of variables for the analysis.

Table B3A5.2 reports the specific definitions of variables included in the analysis (both the dependent variable and explanatory variables), including any needed manipulations, the data source, the Phase III estimation analysis equivalent (either the corresponding variable(s) in the Section 316(b) Phase III Detailed Industry Questionnaire or other source outside the questionnaire), and any issues in variable definition.

Table B3A5.2: Variables For Capital Expenditure Modeling Analysis

Variables for Regression Analysis			Phase III Analysis Equivalent	Comment / Issue
Variable	**Source**	**Calculation**		
Dependent Variable				
***Gross* expenditures on fixed assets: CAPEX**, includes outlays to replace, and add to, existing capital stock	Value Line	Obtained from VL as **Capital Spending per Share**. **CAPEX** calculated by multiplying by **Average Shares Outstanding**.	None: to be estimated based on estimated coefficients.	*This value and all other dollar values in the regression analysis were deflated to 2002 using 2-digit SIC PPI values.*
Explanatory Variables				
Firm-Specific Variables				
Return On Assets: ROA	Value Line	**ROA = Operating Income / Total Assets**. Both **Operating Income**, defined as Revenue less Operating Expenses (CoGS+SG&A), and **Total Assets** were obtained directly from VL.	From Survey: **Revenue** *less* **Total Operating Expenses** (**Material & Product Costs** + **Production Labor** + **Cost of Contract Work** + **Fixed Overhead** + **R&D** + **Other Costs & Expenses**)	Would have preferred an after-tax concept in numerator *and* a deployed production capital concept in denominator. However, VL provides no tax value *per se* and would require calculation of tax using an estimated tax rate, which could introduce error. Also neither VL nor Phase III survey data provide sufficient information to get at deployed production capital.

Table B3A5.2: Variables For Capital Expenditure Modeling Analysis

Variables for Regression Analysis			Phase III Analysis Equivalent	Comment / Issue
Variable	**Source**	**Calculation**		
Revenue: REV	Value Line	**REV = Revenues**. **Revenues** directly available from VL.	From Survey: **Revenue**	In the log-linear formulation this variable captures percent change/growth in revenues. However, the use of the log-linear formulation, eliminates the potential to set the growth term to zero in estimating baseline capital outlays for Phase III facilities. During the specification of the regression model for the MP&M final regulation, **Total Assets** was also tested as a scale variable. Since it provided a good, but not as strong, an explanation, as **REV** it was not included in the final specification. Based on this previous finding, **Total Assets** was not considered while specifying the Phase III regression model.
Capital Turnover Rate: CAPT	Value Line	**CAPT = Depreciation / Total Assets. Depreciation** and **Total Assets** directly available from VL.	From Survey: **Depreciation / Total Assets**	Would have preferred denominator of *net fixed assets* instead of *total assets*. However, VL provides detailed balance sheet information for only the four most recent years. Not possible to separate current assets and intangibles from total assets.
Capital Intensity: CAPI	Value Line	**CAPI = Total Assets / Revenue. Total Assets** and **Revenue** directly available from VL	From Survey: **Total Assets / Revenue**	As above, would have preferred *net fixed assets* instead of *total assets*, but needed data are not available from VL for the full analysis period.
Market-to-Book Ratio: MV/B	Value Line	**MV/B** = average market price of common equity (**Price**) divided by book value of common equity (**Book Value per Share**). **Price** and **Book Value per Share** directly available from VL.	N/A (see Comment/Issue)	During specification of the MP&M regression model, **MV/B** was found to highly correlated with other, more important explanatory variables, which makes sense, given that equity terms would be derived from more fundamental factors, such as **ROA**. Thus, **MV/B** was omitted from the MP&M regression model. As a result, **MV/B** was not considered during the specification of the Phase III regression model which eliminated the need to define an approach to use this variable with Phase III survey data.

Table B3A5.2: Variables For Capital Expenditure Modeling Analysis

Variables for Regression Analysis			Phase III Analysis Equivalent	Comment / Issue
Variable	**Source**	**Calculation**		
General Business Environment Variables				
Interest on 10-year, A-rated industrial debt: DEBTCST	Moody's Investor Services	**DEBTCST =** annual average of rates for each data year	Use average of **DEBTCST** rates at time of Phase III survey.	10-year maturity, industry debt selected as reasonable benchmark for industry debt costs. 10 years became "standard" maturity for industrial debt during 1990s.
Index of Leading Indicators: ILI	Conference Board	Monthly index series available from Conference Board. **ILI** = geometric mean of current year values.	Use average of **ILI** values at time of Phase III survey.	During specification of the MP&M regression model, EPA found that **ILI** and the **CAPPRC** (see below) are highly correlated. Thus, **ILI** was omitted from the MP&M regression model. As a result, **ILI** was not considered during the specification of the Phase III regression model.
Capacity Utilization by Industry: CAPUTIL	Federal Reserve Board (Dallas Federal Reserve)	Monthly index series available from Federal Reserve. **CAPUTIL =** current year average value.	Use average of **CAPUTIL** values at time of Phase III survey.	
Producer Price Index series for capital equipment: CAPPRC	Bureau of Labor Statistics (BLS)	Annual average values available from BLS. **CAPPRC** = current year average value as reported by BLS.	Use average of **CAPPRC** values at time of Phase III survey.	BLS reports PPI series for capital equipment based on "consumption bundles" defined for manufacturing and non-manufacturing industries. For this analysis, EPA used the PPI series based on the manufacturing industry bundle.

Source: U.S. EPA analysis, 2004.

B3A5-3 SELECTING THE REGRESSION ANALYSIS DATASET

In addition to specifying the variables to be used in the regression analysis, EPA also needed to select the public firm dataset on which the analysis would be performed.

As noted above, EPA used the Value Line Investment Survey as the source for public firm data. VL includes over 8,500 publicly traded firms and identifies firms' principal business both by a broad industry classification (e.g., Paper/Forest) and by an SIC code assignment. Value Line's SIC code definitions do not match the U.S. Census Bureau's SIC code definitions; however, in most instances a Value Line SIC code can be reasonably matched to one or several U.S. Census Bureau defined SIC codes. To build the public firm dataset corresponding to the Phase III sectors (SIC 26: Paper and allied products, SIC 28: Chemicals and allied products, SIC 29: Petroleum and coal products, and SIC 33 Primary metal industries) , EPA initially selected all firms included in the Value Line SIC code families:

- 2600: Paper/forest products,
- 2640: Packaging and container,
- 2810: Chemical (basic),
- 2813: Chemical (diversified),
- 2820: Chemical (speciality),
- 2830: Biotechnology,

- 2834: Drug,
- 2840: Household products,
- 2844: Toiletries/cosmetics,
- 2900: Petroleum (integrated),
- 3311: Steel (general), and
- 3312: Steel (integrated).

In order to derive a dataset of firms whose business activities closely match the activities of firms included in the Phase III sample survey EPA made or attempted to make the following revisions to the initial dataset:

- EPA found that the VL SIC code definition does not include categories which match SIC 331 and SIC 335 (combined together to form the aluminum sector in the Phase III analysis). Since U.S. aluminum companies are generally vertically integrated (S&P, 2001), most aluminum companies own large bauxite reserves and mine bauxite ore. As such, these firms are classified in VL under SIC 1000: Metals and mining. EPA reviewed the business activities of firms listed in SIC 1000: Metals and mining, and included only those firms described as aluminum companies in the regression analysis dataset.

- EPA reviewed the business activities of firms listed in SIC 3400: Metal fabricating, however, no firms whose activities matched those described within the profiles of the Phase III Manufacturing Sectors were found.[3]

- EPA reviewed the business activities of firms listed in SIC 2840: Household products and SIC 2844: Toiletries/cosmetics, and retained only those firms in the dataset whose activities matched those described within the profiles of the Phase III Manufacturing Sectors (see footnote 4).

- EPA deleted firms within SIC 2600: Paper/forest products whose business activities are solely limited to timber/lumber production. These facilities are unlikely to use cooling water intake structures and therefore fall outside the Phase III Manufacturing Sectors.

- EPA reviewed the business activities of firms listed in SIC 2830: Biotechnology and SIC 2834: Drug in order to exclude firms that are exclusively research and development (R&D) firms and are unlikely to use cooling water intake structures. However, based on the information provided by Value Line EPA was unable to segregate R&D firms from the rest of the firms listed in these SIC codes.

- EPA only retained firms in the VL dataset if they are situated in the U.S. or Canada, and for whom financial information is available in U.S. dollars.

On inspection, EPA found that a substantial number of firms did not have data for the full 11 years of the analysis period. The general reason for the omission of some years of data is that the firms did not become publicly listed in their current operating structure – whether through an initial public offering, spin-off, divestiture of business assets, or other significant corporate restructuring that renders earlier year data inconsistent with more recent data – until after the beginning of the 11-year data period.[4] As a result, the omission of observation years for a firm always starts at the beginning of the data analysis period. This systematic front-end truncation of firm observations in the dataset could be expected to bias the analysis in favor of the capital expenditure behavior nearer the end of the 1990s decade. To avoid this problem, EPA removed all firm observations that have fewer than 11 years of data. As a result, the dataset used in the analysis has a total of 2,244 yearly data observations and represents 204 firms.

[3] The profiles only focus on 4-digit SIC categories represented in the sample of facilities which received the Section 316(b) detailed industry questionnaire.

[4] When VL adds a firm to its dataset, it fills in the public-reported data history for the firm for the lesser of 11 years or the length of time that the firm has been publicly listed and thus subject to SEC public reporting requirements.

Table B3A5.3 presents the number of firms by industry classifications.

Table B3A5.3: Number of Firms by Industry Classifications

SIC Industry Classification	Number of Firms
26: Paper and allied products	24
28: Chemicals and allied products	136
29: Petroleum and coal products	20
33: Primary metal industries	24

B3A5-4 SPECIFICATION OF MODELS TO BE TESTED

On the basis of the variables listed above and their hypothesized relationship to capital outlays, EPA specified a time-series, cross sectional model to be tested in the regression analysis. EPA's dataset consisted of 204 cross sections observed at 11 years (1992 through 2002). The general structure of this model was as follows:

$$CAPEX_{i,t} = f(ROA_{i,t}, REV_{i,t}, CAPT_{i,t}, CAPI_{i,t}, DEBTCST_{i,t}, CAPPRC_t, CAPUTIL_{j,t})$$

Where:

$CAPEX_{i,t}$	=	capital expenditures of firm *i*, in time period *t*;[5]
t	=	year (year = 1992, . . . , 2002);
i	=	firm *i* (*i* = 1, . . . , 204);
j	=	industry classification *j*
$ROA_{i,t}$	=	return on total assets for firm *i* in year *t*;
$REV_{i,t}$	=	revenue ($ millions) for firm *i* in year *t*;
$CAPT_{i,t}$	=	capital turnover rate for firm *i* in year *t*;
$CAPI_{i,t}$	=	capital intensity for firm *i* in year *t*;
$DEBTCST_t$	=	financial cost of capital in year *t*;
$CAPPRC_t$	=	price of capital goods in year *t*;
$CAPUTIL_{j,t}$	=	the Federal Reserve Board's Index of Capacity utilization for a given industry *j* in year *t*.

EPA only tested log-linear model specifications for this analysis.[6] The main advantage of the log-linear model is that it incorporates directly the concept of percent change in the explanatory variables. Specifying the key regression variables as logarithms permitted EPA to estimate directly as the coefficients of the model, the elasticities of capital expenditures with respect to firm financial characteristics and general business environment factors. The following paragraphs briefly discuss testing of the log-linear forms of the model. Parameter estimates are presented for the final log-linear model only.

EPA specified a log-linear model, as follows:

$$\ln(CAPEX_{i,t}) = \alpha + \Sigma[\beta_x \ln(X_{i,t})] + \Sigma[\gamma_y \ln(Y_t)] + \epsilon$$

[5] All dollar values were deflated to 2002 using 2-digit SIC PPI values.

[6] While specifying the MP&M regression model, EPA tested both linear and log-linear model specifications. The pattern of coefficient significance was found to be better in the log-linear model. In addition, the log-linear model offered advantages in terms of retention of early time period observations (by eliminating the need to use percent change variables) and variable specifications, and helped to reduce outlier effects in the model . As a result, EPA selected a log-linear specification as the final regression model for the MP&M final regulation. Based on these reasons and the similarity of industry sectors analyzed for the two regulations, EPA decided to test only log-linear model specifications for the Phase III regression model.

Where:

$CAPEX_{i,t}$	=	capital expenditures of firm *i*, year *t*;
β_x	=	elasticity of capital expenditures with respect to firm characteristic X;
$X_{i,t}$,	=	a vector of financial characteristics of firm *i*, year *t*;
γ_y	=	elasticity of capital expenditures with respect to economic indicator Y;
Y_t	=	a vector of economic indicators, year *t*; for CAPUTIL, Y is also differentiated by industry classification
ϵ	=	an error term; and
$\ln(x)$	=	natural log of *x*

Based on this model, the elasticity of capital expenditures with respect to an explanatory variable, for example, return on assets is calculated as follows:

$$E(CAPEX) = \frac{d\ln(CAPEX)}{d\ln(ROA)} = \frac{d(CAPEX)/CAPEX}{d(ROA)/ROA}$$

Since logarithmic transformation is not feasible for negative and zero values, such values in the VL public firm dataset required linear transformation to be included in the analysis. The following variables in the sample required transformation:

- CAPEX: Eighteen firms in the sample reported zero capital expenditures at least in one time period. EPA set these expenditures to $1.

- REVENUE: Seven firms reported negative revenues in at least one time period. Because these are likely due to accounting adjustments from prior period reporting, EPA set negative revenues for these firms to $1.

- ROA: the values for return on assets in the public firm sample range from -2.9 to 0.7. Approximately 34 percent of the firms in the dataset reported negative ROAs in at least one year. To address this issue while reducing potential effects of data transformation on the modeling results, EPA used the following data transformation approach:[7]

  - EPA excluded 27 firms with *any* annual ROA values below the 95th percentile of the ROA distribution (i.e., ROA ≤ - 0.51).

  - EPA used an additive data transformation to ensure that remaining negative ROA values were positive in the logarithm transformation. The additive transformation was performed by adding 0.51 to all ROA values.

As a result of the data transformation procedures outlined above, the VL public firm dataset on which the regression model is based was reduced to 177 firms (204 - 27 firms) and 1,947 yearly data observations.

The analysis tested several specifications of a log-linear model, including models with the intercept and slope dummies for different industrial sectors and models with the intercept suppressed.[8] Slope dummies were used to

[7] While specifying the MP&M regression model EPA conducted a sensitivity analysis to examine the degree to which the estimated model was affected by this data transformation. Results of this analysis showed that the data transformation produces results that are compatible with a model considering only positive ROA values and a model considering all ROA values. As a result, the Phase III regression model utilized the same data transformation procedure.

[8] While specifying the MP&M regression model, EPA also tested specifications that included the following structural modifications: (1) testing contemporary vs. lagged specification of certain explanatory variables: e.g., using prior, instead of current period revenue, REV, as an explanatory variable; (2) testing scale-normalized specification of the dependent variable: e.g., using CAPEX/REV as the dependent variable instead of simple CAPEX; (3) testing flexible functional forms that included quadratic terms; and (4) testing additional explanatory variables including the index of 10 leading economic indicators (ILI) and market-to-book ratio (MV/B). Because EPA found

test the influence of industry classification on the elasticity of capital expenditures with respect to an explanatory variable: e.g., using the product of an industry classification dummy variable and CAPPRC to test whether certain industries responded differently to change in price of capital equipment over time. Following review of the different models tested, EPA concluded that the estimated coefficients did not vary, significantly, by industry and thus selected the simple log-linear model, with the intercept and no slope dummies as the basis for the 316(b) Phase III capital expenditures analysis. The results for this model are summarized below.

Cross-sectional, time-series datasets typically exhibit both autocorrelation and group-wise heteroscedasticity characteristics. Autocorrelation is frequently present in economic time series data as the data display a "memory" with the variation not being independent from one period to the next. Heteroscedasticity usually occurs in cross-sectional data where the scale of the dependent variable and the explanatory power of the model vary across observations. Not surprisingly, the dataset used in this analysis had both characteristics. Therefore, EPA estimated the specified model using the generalized least squares procedure. This procedure involves the following two steps:

- First, EPA estimated the model using simple OLS, ignoring autocorrelation for the purpose of obtaining a consistent estimator of the autocorrelation coefficient (ρ);

- Second, EPA used the generalized least squares procedure, where the analysis is applied to transformed data. The resulting autocorrelation adjustment is as follows:

$$Z_{i,t} = Z_{i,t} - \rho Z_{i,t-1}$$

where Z_{it} is either dependent or independent variables.

EPA was unable to correct the estimated model for group-wise heteroscedasticity due to computational difficulties. The statistical software used in the analysis (LIMDEP) failed to correct the covariance matrix due to the very large number of groups (i.e., 177 firms) included in the dataset. Application of other techniques to correct for group-wise heteroscedasticity was not feasible due to time constraints. The estimated coefficients remain unbiased; however, they are not minimum variance estimators. Regression results reveal strong systematic elements influencing capital expenditures: the analysis finds both statistically significant and intuitive patterns that influence firm's investment behavior. We find a strong systematic element of capital expenditures variation which allows forecasting of capital expenditures based on firm and business environment characteristics.

Table B3A5.4 presents model results. The model has a fairly good fit, with adjusted R^2 of 0.81. All coefficients have the expected sign and all but one variable (cost of debt capital) are significantly different from zero at the 95th percentile.

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that these structural modifications either did not improve the fit of the MP&M regression model or resulted in the introduction of multicollinearity among variables, these structural modifications were not tested while specifying the Phase III regression model.

Table B3A5.4: Time Series, Cross-Sectional Model Results

Variable	Coefficient	t-Statistics
Constant	21.880	2.618
Ln(ROA)	0.526	3.964
Ln(REV)	1.129	58.450
Ln(CAPT)	0.687	11.085
Ln(CAPI)	1.078	18.491
Ln(DEBTCST)	-0.789	-1.605
Ln(CAPPRC)	-5.957	-4.369
Ln(CAPUTIL)	1.716	2.842
Autocorrelation Coefficient		
r	0.385	18.402

The empirical results show that among the firm-specific variables, the output variable (REV) is a dominant determinant of firms' investment spending. A positive coefficient on this variable means that larger firms invest more, all else equal, which is clearly a simple expected result. In addition, as expected, firms with higher financial performance and better investment opportunities (ROA) invest more, all else equal: for each one percent increase in ROA, a firm is expected to increase its capital outlays by 0.53 percent. Other firm-specific characteristics were also found important and will aid in differentiating the expected capital outlay for Phase III facilities according to firm-specific characteristics. Firms that require more capital to produce a given level of business activity (i.e., firms that have high capital intensity, CAPI) tend to invest more: a one percent increase in capital intensity leads to a 1.08 percent increase in capital spending. Higher capital turnover/shorter capital life (CAPT) also has a positive effect on investment decisions: a one percent increase in capital turnover rate translates to a 0.69 percent increase in capital outlays.

The model also shows that current business environment conditions play an important role in firms' decision to invest. Negative signs on the capital price (CAPPRC) and debt cost (DEBTCST) variables match expectations, indicating that falling (either relatively or absolutely) capital equipment prices and less costly credit are likely to have a positive effect on firms' capital expenditures. The most influential factor is capital equipment prices for manufacturing facilities. A one percent increase in the capital price index (CAPPRC) leads to a 5.96 percent decrease in capital investment. Capacity utilization is also an influential factor: a one percent increase in the Federal Reserve Index of Capacity Utilization for the relevant industrial sector (CAPUTIL) leads to a 1.7 percent increase in capital investments. The fact that these systematic variables are significant in the regression analysis means that EPA will be able to control for economy- and industry-wide conditions in estimating capital outlays for Phase III facilities.

B3A5-5 MODEL VALIDATION

To validate the results of the regression analysis, EPA used the estimated regression equation to calculate capital expenditures and then compared the resulting estimate of capital expenditures with actual data. EPA used two methods to validate its results:

- EPA used median values for explanatory variables from the Value Line data as inputs to estimate capital expenditures and then compared the estimated value to the median reported capital expenditures, and

- EPA used Phase III survey data to estimate capital expenditures and then compared the estimated values to depreciation reported in the survey.

First, EPA estimated capital expenditures for a hypothetical firm based on the median values of the four dependent variables from the Value Line data and the relevant values of the three economic indicators. The estimated capital expenditures for this hypothetical firm are $43 million. EPA then compared this estimate to the median value of capital expenditures from the Value Line data. The median capital expenditure value in the dataset is $36 million, which provides a close match to the estimated value. This is not surprising since the same dataset was used to estimate the regression model and to calculate the median values used in this analysis.

EPA also used Phase III survey data to confirm that the estimated capital expenditures seem reasonable. Because the Phase III survey does not provide information on capital expenditures, EPA compared the capital expenditure estimates to the depreciation values reported in the survey. Depreciation had been proposed as a possible surrogate for cash outlays for capital replacements and additions. However, depreciation does not capture important variations in capital outlays that result from differences in firms' financial performance.

For this analysis, EPA chose a representative facility from each of the four Phase III primary manufacturing sectors for model validation. The selected facility for each sector corresponds as closely as possible to the hypothetical median facility in the sector based on the distribution of facility revenues and facility return on assets. For each of the four facilities, EPA estimated capital expenditures using the estimated regression equation and facility financial data. Table B3A55 shows the estimated regression coefficients, financial averages for the four Phase III sectors, estimated facility capital expenditures, reported facility depreciation, and the comparison of capital expenditures and depreciation.

As shown in Table B3A5.5, the estimated model provides reasonable estimates of capital expenditures.

Table B3A5.5: Estimation of Capital Outlays for Phase III Sample Facilities: Median Facilities Selected by Revenue and ROA Percentiles

Sectors	Pre-Tax Return on Assets (ROA)	Revenue ($2003, millions)	Capital Turnover Rate	Capital Intensity	Cost of Debt	Price of Capital Goods	Capacity Utilization	Estimated Capital Expenditures ($2003, millions)	Depreciation ($2003, millions)	Difference between Depreciation and Capital Expenditures ($2003, millions)
Coefficient Intercept (21.88)	*0.53*	*1.13*	*0.69*	*1.08*	*-0.79*	*-5.96*	*1.72*			
Paper and allied products	0.16	$244	0.09	0.89	7.71	137.60	86.24	$18.94	$16.16	($2.78)
Chemicals and allied products	0.22	$237	0.06	1.14	7.71	137.60	79.36	$15.25	$13.66	$1.59
Petroleum and coal products	0.15	$1,470	0.05	0.58	7.71	137.60	91.88	$45.58	$62.95	$17.37
Primary metals industries	0.11	$444	0.06	0.52	7.71	137.60	88.77	$15.58	$18.55	$2.97

Source: U.S. EPA analysis, 2004.

One of the possible implications of the hypothesized relationships and estimated coefficient values from the prior analysis is that a facility's predicted capital expenditures might be expected to increase relative to the facility's actual depreciation as the facility's ROA increases. An extension and somewhat version of this hypothesis is that, at lower ROA values, predicted capital expenditures would be less than the depreciation but, that at higher ROA values, predicted capital expenditures exceed depreciation. These hypotheses are consistent with the expectation that businesses with higher financial performance will have relatively more attractive investment opportunities and are more likely to attract the capital to undertake those investments. EPA examined whether these relationships occur in the 316(b) sample facilities. Specifically, EPA calculated the predicted capital expenditure for each facility and compared these values to the facilities' reported depreciation values. To remove the scale effect of revenue, EPA normalized both the predicted capital expenditure and reported depreciation values by dividing by the three-year average of revenue for each facility. EPA then estimated the simple linear relationship of the resulting revenue-normalized capital expenditure and deprecation values against facility ROA. The four graphs on the following pages present, for each of the four two-digit SIC code sectors, the normalized capital expenditure and deprecation values, and the estimated trend lines for each sector's depreciation and capital expenditures with respect to ROA.[4] The graphs indicate the following:

- The Paper and Allied Products (SIC 26) graph shows depreciation exceeding predicted capital expenditure at low ROA values but this relationship reverses with predicted capital expenditure exceeding depreciation as ROA increases. Thus, the calculations for these facilities match the hypothesized relationship.

- The Chemicals and Allied Products (SIC 28) graph also shows depreciation exceeding predicted capital expenditure at low ROA values, but again the relationship reverses with predicted capital expenditure exceeding depreciation as ROA increases. This predicted relationship is observed more strongly for facilities in the Chemicals and Allied Products industry than in the Paper and Allied Products industry.

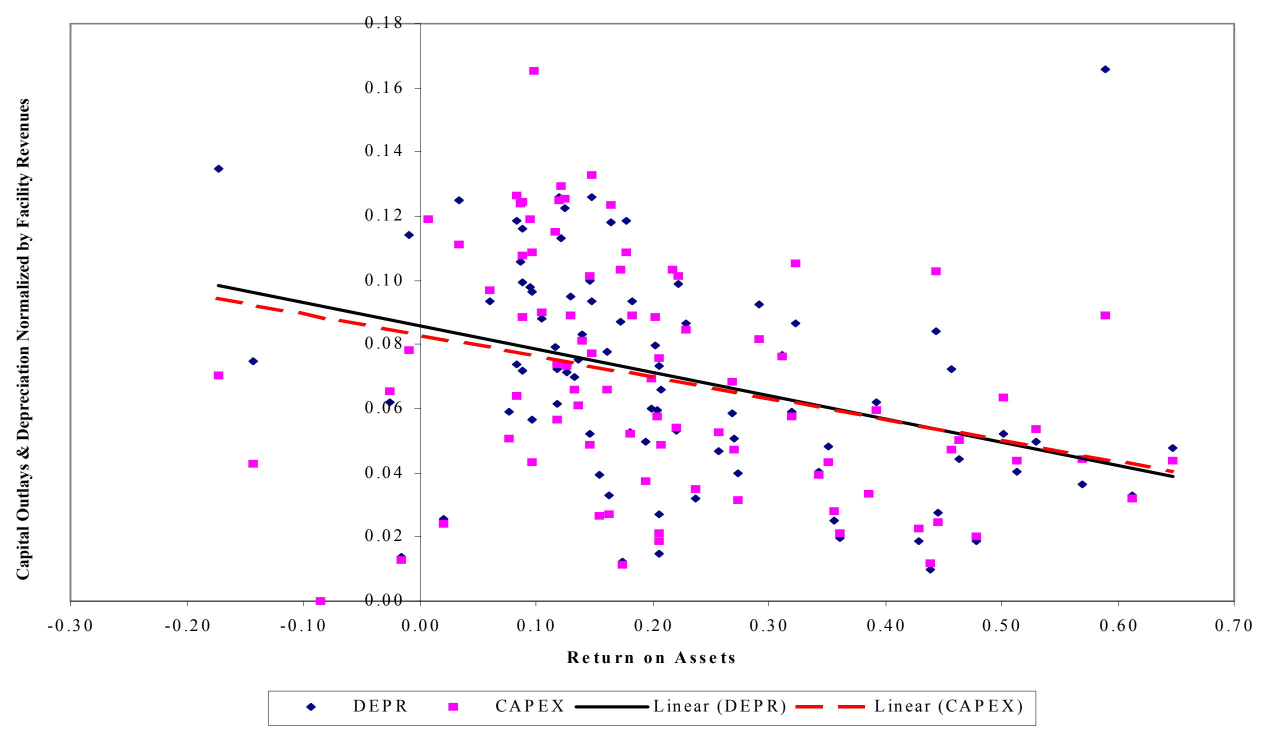
- The Petroleum and Coal Products (SIC 29) graph shows predicted capital expenditures exceeding depreciation over the ROA range analyzed. However, the extent of difference does not materially change as ROA increases.

- The Primary Metal Industries (SIC 33) graph also shows predicted capital expenditures exceeding depreciation over the ROA range analyzed. However, unlike for the Petroleum and Coal Products facilities, the amount by which predicted capital expenditures exceeds depreciation increases as ROA increases, thus matching the hypothesized relationship.

In summary, with the exception of facilities in the Petroleum and Coal Products industry, the estimated model produces capital expenditure values that increase relative to reported depreciation with increasing ROA, which matches the hypothesized relationship.

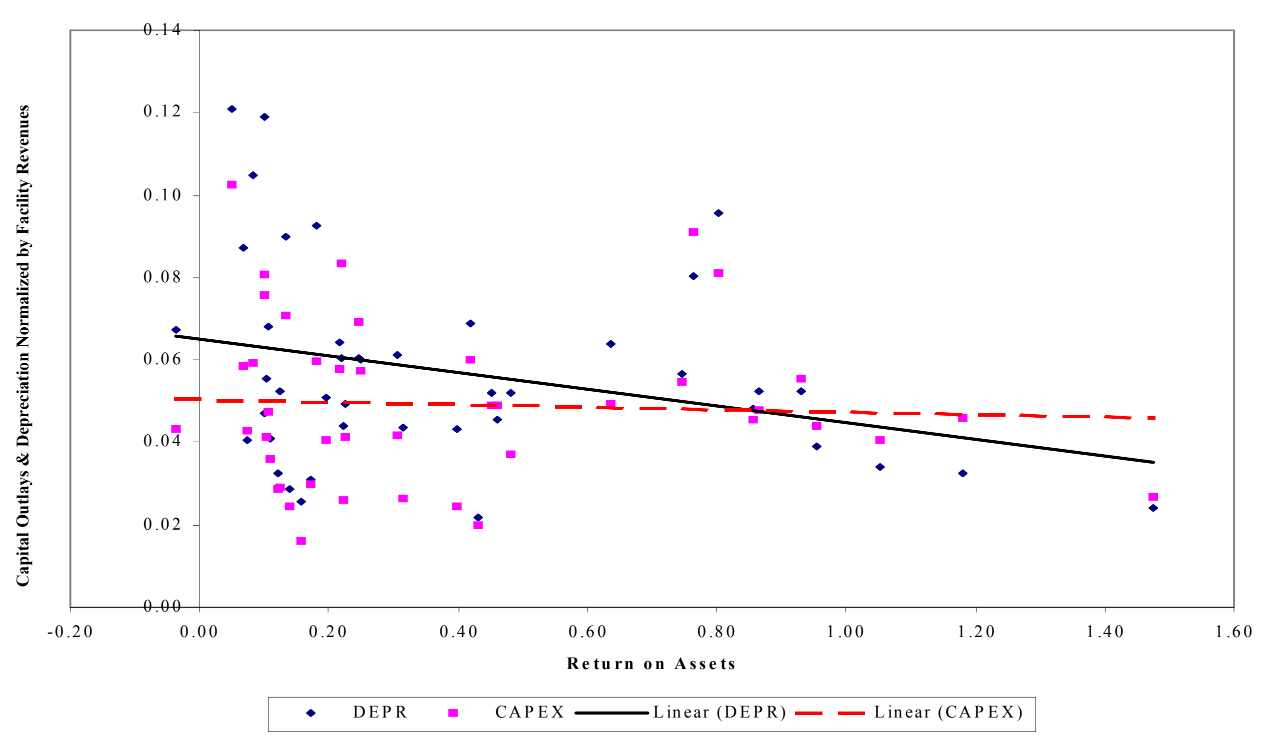
[4] For presentation purposes, two outlier facilities were excluded from the graph for SIC 28: Chemicals and allied products, and one outlier facility was excluded from the graph for SIC 26: Paper and allied products.

Figure B3A5.1: Comparison of Estimated Capital Outlays to Reported Depreciation for Phase III Survey Facilities in the Paper and Allied Products Sector



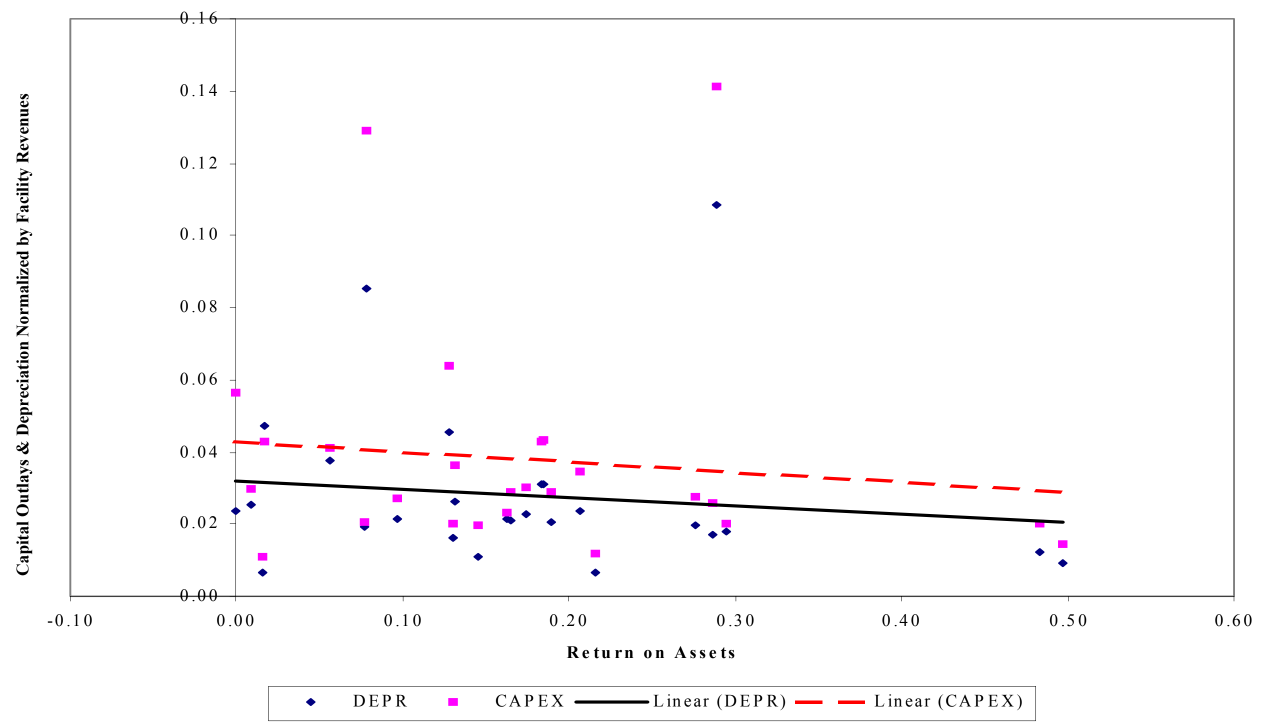
Source: U.S. EPA analysis, 2004.

Figure B3A5.2: Comparison of Estimated Capital Outlays to Reported Depreciation for Phase III Survey Facilities in the Chemicals and Allied Products Sector



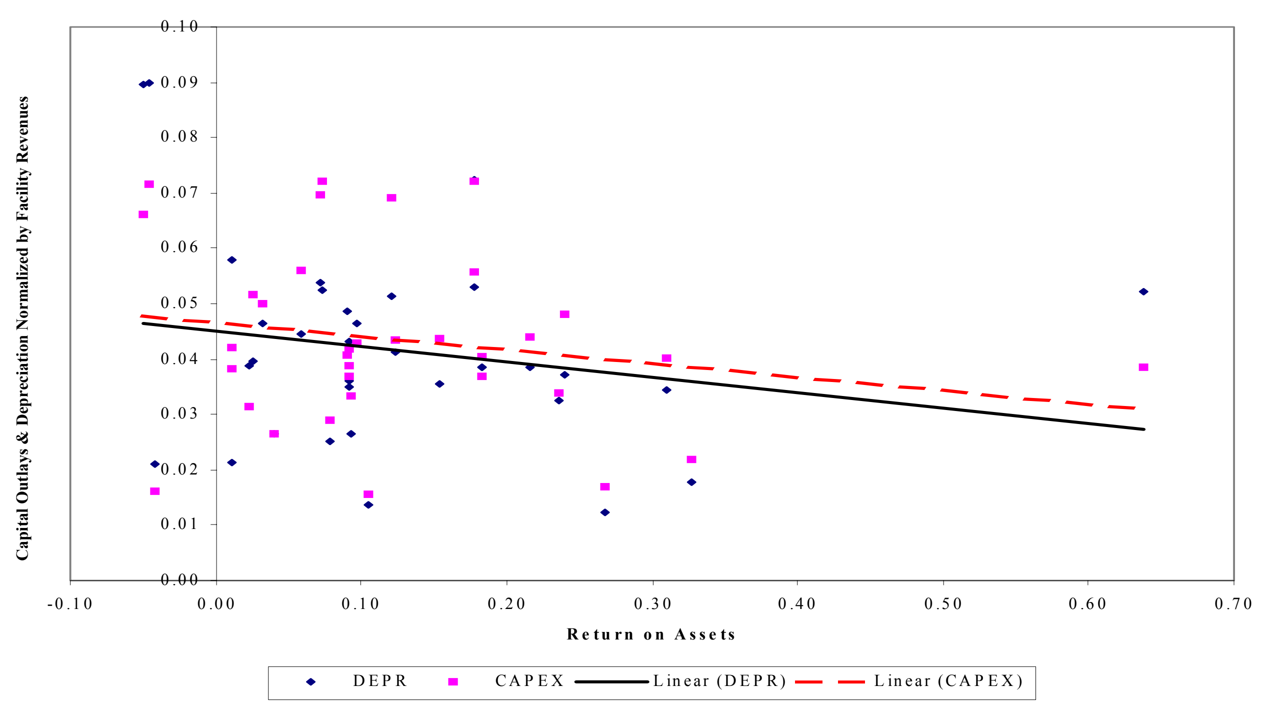
Source: U.S. EPA analysis, 2004.

Figure B3A5.3: Comparison of Estimated Capital Outlays to Reported Depreciation for Phase III Survey Facilities in the Petroleum and Coal Products Sector



Source: U.S. EPA analysis, 2004.

Figure B3A5.4: Comparison of Estimated Capital Outlays to Reported Depreciation for Phase III Survey Facilities in the Primary Metal Industries Sector



Source: U.S. EPA analysis, 2004.

ATTACHMENT B3A5.A: BIBLIOGRAPHY OF LITERATURE REVIEWED FOR THIS ANALYSIS

As noted above, EPA relied on previous studies of investment behavior to select critical determinants of firms' capital expenditures. Empirical results from these studies suggest that investment is most sensitive to quantity variables (output or sales), return-over-cost, and capital utilization (R. Chirinko). Empirical results from more recent studies further found that increasing depreciation rates and capital equipment prices were of first-order importance in the equipment investment behavior in the 1990 (T. Tevlin, K. Whelan). Specifically, declining prices of micro-processor based equipment played a crucial role in the investment boom in the 1990.

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ATTACHMENT B3A5.B: HISTORICAL VARIABLES CONTAINED IN THE VALUE LINE INVESTMENT SURVEY DATASET

All variables are provided for 10 years (except where a firm has been publicly listed for less than 10 years):

- Price of Common Stock
- Revenues
- Operating Income
- Operating Margin
- Net Profit Margin
- Depreciation
- Working Capital
- Cash Flow per share
- Dividends Declared per share
- Capital Spending per share
- Revenues per share
- Average Annual Price-Earnings Ratio
- Relative Price-Earnings Ratio
- Average Annual Dividend
- Return Total Capital
- Return Shareholders Equity
- Retained To Common Equity
- All Dividends To Net Worth
- Employees
- Net Profit
- Income Tax Rate
- Earnings Before Extras
- Earnings per share
- Long Term Debt
- Total Loans
- Total Assets
- Preferred Dividends
- Common Dividends
- Book Value
- Book Value per share
- Shareholder Equity
- Preferred Equity
- Common Shares Outstanding
- Average Shares Outstanding
- Beta
- Alpha
- Standard Deviation

Appendix 6 to Chapter B3: Summary of Moderate Impact Threshold Values by Industry

INTRODUCTION

APPENDIX CONTENTS

Facilities subject to *moderate impacts* from the proposed regulation are expected to experience financial stress short of closure. This analysis uses two financial indicators: (1) Pre-Tax Return on Assets (PTRA) and (2) Interest Coverage Ratio (ICR). These threshold values were calculated at the industry-level and compared to pre- and post-compliance PTRA and ICR values for sample facilities to determine if facilities choosing to remain in business after promulgation of effluent guidelines would experience moderate impacts on their ability to attract and finance new capital. The six industries considered in this analysis are: Paper, Chemicals, Petroleum, Steel, Aluminum (the "Primary Manufacturing Industries"), and Other Industries. The remainder of this appendix describes the sources and methodology used to derive industry-specific moderate impact threshold values.

EPA calculated the thresholds using income and financial structure information by 4-digit SIC code from the Risk Management Association (RMA) *Annual Statement Studies* for eight years 1994-2001 (RMA, 2001; RMA 1998). This source provides quartile values derived from statements of commercial bank borrowers and loan applicants for firms having less than $250 million in total assets. These criteria may introduce bias, since firms with particularly poor financial statements might be less likely to apply to banks for loans, and some types of firms may be more likely to use bank financing than others. However, the RMA data offers the advantage of being available by 4-digit SIC codes and for quartile ranges.

RMA did not provide data for all 4-digit SIC codes associated with an in-scope Section 316(b) facility. Out of 26 SIC codes associated with facilities in the Primary Manufacturing Industries and 14 SIC codes associated with facilities in Other Industries, 10 SIC codes associated with facilities in the Primary Manufacturing Industries (38 percent) and 7 SIC codes associated with facilities in Other Industries (50 percent), had no years of data available. In addition, no data were available for the Aluminum industry, so EPA applied a combined Steel/Aluminum industry value to facilities in those industries.

The 4-digit SIC code data were consolidated into weighted industry averages, weighted by 1997 value of shipments from the Economic Censuses (U.S. DOC, 1997). For each industry and impact measure, a separate threshold was calculated. The use of the RMA data for calculating the threshold values for pre-tax return on assets and interest coverage ratio is outlined below.

B3A6.1 DEVELOPING THRESHOLD VALUES FOR PRE-TAX RETURN ON ASSETS (PTRA)

Pre-tax return on total assets measures management's effectiveness in employing the capital resources of the business to produce income. A low ratio may indicate that a borrower would have difficulty financing treatment investments and continuing to attract investment.

The following data from Risk Management Association *Annual Statement Studies* were used to calculate PTRA:

- *% Profit Before Taxes / Total Assets$_{25th}$* — Ratio of profit before taxes divided by total assets and multiplied by 100 for the lowest quartile of values in each 4-digit SIC code.
- *Operating Profit* — Gross profit minus operating expenses.
- *Profit Before Taxes* — Operating profit minus all other expenses (net).

RMA provides a measure of pre-tax return on assets that approximates the measure that EPA defined for the moderate impact analysis. As defined by RMA, this measure is the ratio of pre-tax *income* to assets, designated ROA_{RMA}:

ROA_{RMA} = Pre-Tax Income (EBT) / $ASSETS_{25th}$

However, as defined by EPA for its analysis, the numerator of the PTRA measure requires the use of earnings before interest and taxes (EBIT) instead of pre-tax income (EBT). Defined as EBIT, the PTRA numerator will capture all return from assets, whether going to debt or equity. To derive a pre-tax, total return value, EPA adjusted RMA's measure of PTRA using the median percentage values of EBIT and EBT available from RMA. This adjustment yields the PTRA measure that EPA used in the moderate impact analysis, designated $ROA_{316(b)}$:

$ROA_{316(b)} = ROA_{RMA} * EBIT / EBT$

Negative values are included in the weighted-industry PTRA averages but a different method is used to adjust the ROA values reported in RMA to the value used in the moderate impact analysis. Specifically, using only those observations (i.e., 4-digit SIC code and year combinations) with positive values for % Profit Before Taxes / Total Assets, Operating Profit, and Profit Before Taxes, EPA calculated an adjustment factor by subtracting the difference between $ROA_{316(b)}$ and ROA_{RMA} as follows:

$ROA_{316(b)}$-ROA_{RMA} = adjustment factor.

Those values were consolidated into industry-specific adjustment factors, weighted by 1997 value of shipments from the Economic Censuses (U.S. DOC, 1997). Each negative PTRA observation from RMA was adjusted by its industry specific adjustment factor to approximate the measure used in the moderate impact analysis:

ROA_{RMA} + industry specific adjustment factor = $ROA_{316(b)}$

The industry specific adjustment factors average 0.40 and range from 0.12 for Paper to 0.55 for the combined Steel/Aluminum industry.

B3A6-2 DEVELOPING THRESHOLD VALUES FOR INTEREST COVERAGE RATIO (ICR)

Interest coverage ratio measures a business' ability to meet current interest payments and, on a pro-forma basis, to meet the additional interest payments under a new loan. A high ratio may indicate that a borrower would have little difficulty in meeting the interest obligations of a loan. This ratio serves as an indicator of a firm's capacity to take on additional debt.

The following data from Risk Management Association *Annual Statement Studies* were used to calculate ICR:

- *EBIT/Interest$_{25th}$* — Ratio of earnings (profit) before annual interest expense and taxes (EBIT) divided by annual interest expense for the lowest quartile of values in each 4-digit SIC code.
- *% Depr., Dep., Amort./Sales$_{med}$* — Median ratio of annual depreciation, amortization and depletion expenses divided by net sales and multiplied by 100.
- *Operating Profit* — Gross profit minus operating expenses.

RMA provides a measure of interest coverage that approximates the measure that EPA defined for the moderate impact analysis. As defined by RMA, this measure is the ratio of earnings before interest and taxes to interest, designated ICR_{RMA}:

ICR_{RMA} = EBIT / $INTEREST_{25th}$

However, as defined by EPA for its analysis, the numerator of the ICR measure requires the use of earnings before interest, taxes, depreciation, and amortization (EBITDA) instead of earnings before interest and taxes (EBIT). Defined this way, the ICR numerator will include all operating cash flow that could be used for interest payments. To derive the desired ICR value (designated $ICR_{316(b)}$), EPA adjusted the RMA value as outlined below:

$ICR_{316(b)}$ = EBITDA / INTEREST

Therefore, $ICR_{316(b)} = ICR_{RMA} * (EBIT + DA) / EBIT$
or $ICR_{316(b)} = ICR_{RMA} * \{1+ [(DA / SALES) / (EBIT / SALES)]\}$

For consistency of calculation, EPA used the median values available from RMA for the adjusting both the numerator (DA / SALES) and denominator (EBIT / SALES) terms.[1]

EPA used the same method as described above to adjust the negative ICR values reported in RMA to the value used in the moderate impact analysis. Including only those observations with positive values for EBIT/Interest, % Depr., Dep., Amort./Sales, and Operating Profit, an adjustment factor was calculated by subtracting the difference between $ICR_{316(b)}$ and ICR_{RMA} as follows:

$ICR_{316(b)}$-ICR_{RMA} = adjustment factor.

An industry specific adjustment factor was calculated for ICR values similar to the PTRA. Each negative ICR observation from RMA was adjusted by its industry specific adjustment factor to approximate the measure used in the moderate impact analysis:

ICR_{RMA} + industry specific adjustment factor = $ICR_{316(b)}$

The industry specific adjustment factors average 0.65 and range from 0.55 for Petroleum to 0.70 for Paper and the combined Steel/Aluminum industry.

[1] Numerator (% Depr., Dep., Amort./Sales) is available for quartile values; denominator (Operating Profit) only for median values.

B3A6-3 SUMMARY OF RESULTS

Table B3A6.1 reports the resulting threshold values for PTRA and ICR by industry. The PTRA values range from 1.8 percent for Other Industries to 2.9 percent for Chemicals. The ICR values range from 2.0 for Other Industries to 2.4 for Chemicals.

Table B3A6.1: Summary of Moderate Impact Thresholds by Industry
based on 25th percentile value of firms reporting data to RMA

Industry	Pre-Tax Return on Assets (PTRA)	Interest Coverage Ratio (ICR)
Paper	2.1%	2.2
Chemicals	2.9%	2.4
Petroleum	2.1%	2.2
Steel/Aluminum	2.0%	2.1
Other Industries	1.8%	2

Source: RMA, 2001; RMA, 1998; U.S. Economics Census, 1997; U.S. EPA Analysis, 2004.

REFERENCES

U.S. Department of Commerce. 1997. Bureau of the Census. *Census of Manufacturers, Census of Transportation, Census of Wholesale Trade, Census of Retail Trade, Census of Service Industries.*

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Appendix 7 to Chapter B3: Analysis of Baseline Closure Rates

INTRODUCTION

This appendix presents information on the annual entry and closure of establishments in the Primary Manufacturing Industries.

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B3A7-1 ANNUAL ESTABLISHMENT CLOSURES

EPA used the *dynamic data* from the Statistics of U.S. Businesses (SUSB) to estimate the rate at which facilities in these industries leave the industry each year. The SUSB data report numbers of establishments starting up, closing, expanding employment and contracting employment each year from 1989 through 2001 (the latest year currently available).

EPA compared the percent of facilities predicted to close in the baseline closure analysis to typical closure rates in the five primary industries. The SUSB data are organized by 3-digit SIC code for years 1990 through 1998, and 4-digit NAICS code for years 1999 through 2001. As a result, it is not possible to compile a series of data consistently aligned with the industries profiled. Nevertheless, EPA believes the SUSB data can provide a general measure of establishment closures for comparison for the broad industry segments.

Table B3A7.1 shows the percentage of facilities assessed as closures in the baseline analysis, and the range and average of closure rates for each of the five Primary Manufacturing Industries. As reported in the table, between 1.4 percent and 12.5 percent of all facilities in these industries close annually. The estimated baseline closure rates for facilities in the Steel and Aluminum industries are higher than the observed closure rates in these industries, as reported in SUSB data. However, EPA's baseline closure rates are estimated from sample survey data and are thus subject to the statistical uncertainty of the sample survey. EPA believes the individual sample facility analyses accurately represent the baseline financial condition of the facilities, based on the data provided in the facility questionnaires.

Table B3A7.1: Predicted Baseline Closures and Annual Percentage of Closures for Primary Manufacturing Industries (1990-2001)

Sector	Percent of 316(b) Facilities Assessed as Baseline Closures	Percent of Establishments Closing	
		Range	Average
Paper	13.6%	1.4% - 9.8%	5.0%
Chemicals	2.2%	2.3% - 9.2%	6.4%
Petroleum	13.9%	3.3% - 10.6%	6.6%
Steel	36.8%	4.6% - 10.0%	6.5%
Aluminum	33.3%	2.3% - 12.5%	6.2%
Total	**13.6%**	**1.4% - 12.5%**	**6.1%**

Source: Small Business Administration, Statistics of U.S. Businesses.

REFERENCES

Small Business Administration. *Statistics of U.S. Businesses*.
Available at: http://www.sba.gov/ADVO/stats/data.html.

U.S. Department of Commerce (U.S. DOC). 1997. Bureau of the Census. *1997 Economic Census Bridge Between NAICS and SIC.*

Chapter B4: 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 that could result from regulation of facilities in Phase III. Based on the proposed design intake flow threshold-based options in today's proposed rule, Electric Generators would not be subject to national categorical requirements under the proposed Phase III rule. However, in developing the proposed rule, EPA analyzed other flow threshold options that would have subjected Electric Generators to national requirements. This chapter provides a profile of this industry, while Chapter B5 provides the economic impact analysis for this industry, based on the other threshold options considered – but not proposed – by EPA.

CHAPTER CONTENTS

The electric power industry is one of the most extensively studied industries. The Energy Information Administration (EIA), among others, publishes a multitude of reports, documents, and studies on an annual basis. This profile is not intended to duplicate those efforts. Rather, this profile compiles, summarizes, and presents those industry data that are important in the context of the proposed rule for Phase III existing facilities. 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.

The remainder of this profile is organized as follows:

- Section B4-1 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 B4-2 provides data on industry production, capacity, and geographic distribution.
- Section B4-3 focuses on electric generating facilities potentially subject to Phase III regulation. This section provides information on the physical, geographic, and ownership characteristics of the potential Phase III generators.
- Section B4-4 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.

B4-1 INDUSTRY OVERVIEW

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

B4-1.1 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, 2004):[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) regulation. The remainder of this profile will focus on the generation sector of the industry.

B4-1.2 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, 2004):

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[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.

- ***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 (MW)*** 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, 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 Unit:*** "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 Unit***: "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."

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 options evaluated for this proposed 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 B4-1 provides data on the number of existing power plants, by prime mover and regulatory status. 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.

[3]Form EIA-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.

Table B4-1: Number of Existing Utility and Nonutility Plants by Prime Mover in 2001

Prime Mover	Number of Plants		
	Utility[a]	**Nonutility**[a]	**Total**
Steam Turbine	635	903	1,538
Combined-Cycle	59	239	298
Gas Turbine	308	426	734
Internal Combustion	557	346	903
Hydroelectric	900	490	1,390
Other	22	134	156
Total	**2,481**	**2,538**	**5,019**

[a] See definition of utility and nonutility in Section B4-1.3.

Source: U.S. DOE, 2001a.

B4-1.3 Ownership

The U.S. electric power industry consists of two broad categories of firms that own and operate electric generating plants: traditional electric utilities and nontraditional participants. Generally, they can be defined as follows (adapted from U.S. DOE, 2003a):

❖ ***Traditional electric utilities***

Traditional electric utilities are regulated and traditionally vertically integrated entities. They 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. Electric utilities can be further divided into four major ownership categories: investor-owned utilities, publicly-owned utilities, rural electric cooperatives, and Federal utilities. Each category is discussed below (U.S. DOE, 2004).

- **Investor-owned utilities (IOUs)** are privately owned entities. Like all private businesses, investor-owned electric utilities have the fundamental objective of producing a return for their investors. These utilities either distribute profits to stockholders as dividends or reinvest the profits. Investor-owned electric utilities are granted service monopolies in certain geographic areas and are obliged to serve all consumers. As franchised monopolies, these utilities are regulated and required to charge reasonable prices, to charge comparable prices to similar classifications of consumers, and to give consumers access to services under similar conditions. Most investor-owned electric utilities are operating companies that provide basic services for the generation, transmission, and distribution of electricity. The majority of investor-owned utilities perform all three functions. In 2001, IOUs operated 1,148 facilities, which accounted for approximately 44% of all U.S. electric generation capacity (U.S. DOE, 2001a).

- **Publicly-owned utilities** are nonprofit local government agencies established to provide service to their communities and nearby consumers at cost. Publicly owned electric utilities include municipalities, State authorities, and political subdivisions (e.g., public power districts, irrigation projects, and other State agencies established to serve their local municipalities or nearby communities). Excess funds or “profits” from the operation of these utilities are put toward 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, however, generate and transmit electricity as well. 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, municipalities operated 785 facilities (4.9% of U.S. capacity), States operated 85 facilities (2.1% of U.S. capacity), and political subdivisions operated 103 facilities (2.0% of U.S. capacity) (U.S. DOE, 2001a).

- **Cooperative utilities** (or "coops") are member-owned entities created to provide electricity to those members. These utilities, established under the Rural Electrification Act of 1936, operate in rural areas with low concentrations of consumers because these areas historically have been viewed as uneconomical operations for IOUs. 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 3.2% of all U.S. electric generation capacity (U.S. DOE, 2001a).

- **Federal electric utilities** are part of several agencies in the U.S. Government: the Army Corps of Engineers (Department of Defense), the Bureau of Indian Affairs and the Bureau of Reclamation (Department of the Interior), the International Boundary and Water Commission (Department of State), the Power Marketing Administrations (Department of Energy), and the Tennessee Valley Authority (TVA). Three Federal agencies operate generating facilities: TVA, the largest Federal producer; the U.S. Army Corps of Engineers; and the U.S. Bureau of Reclamation. In 2001, the ten Federal electric utilities operated 194 facilities, accounting for 7.6% of total U.S. electric generation capacity (U.S. DOE, 2001a).

Traditional electric utilities are hereafter referred to as "***utilities***".

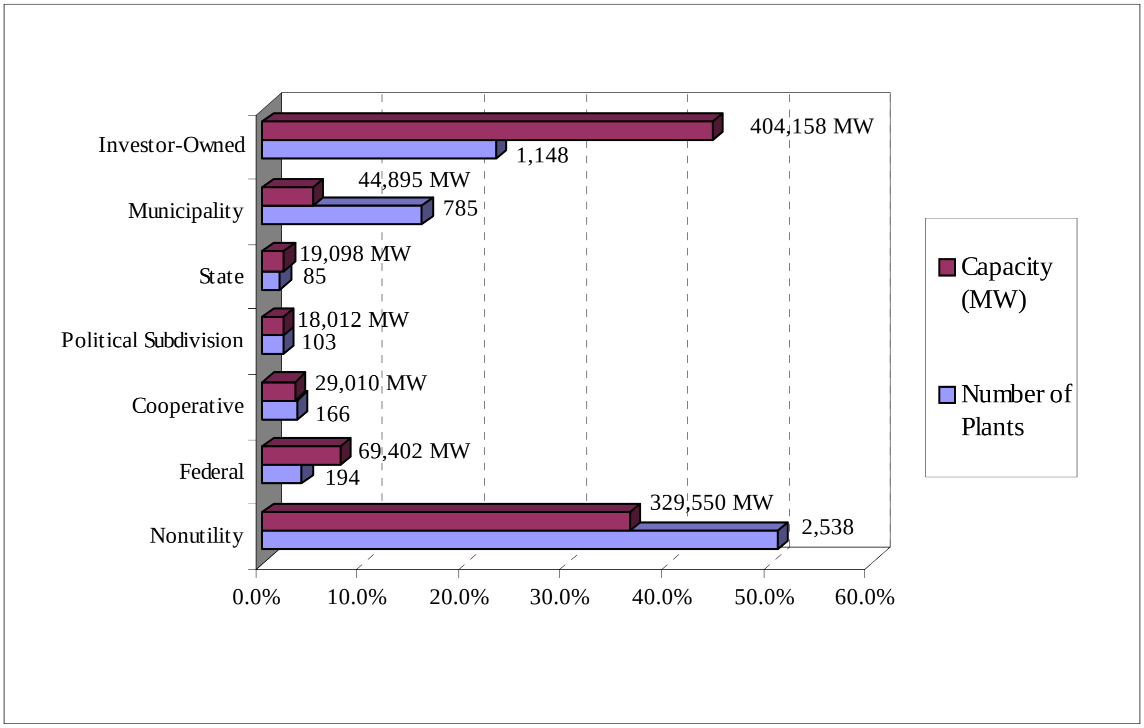
❖ ***Nontraditional participants***

Nontraditional participants are unregulated entities and include energy service providers, power marketers, independent power producers (IPPs), and combined heat and power plants (CHPs, formerly referred to as cogenerators). IPPs own or operate facilities whose primary business is to produce electricity for use by the public; they are not aligned with distribution facilities. CHPs are plants designed to produce both heat and electricity from a single heat source. CHPs can be independent power producers, or industrial or commercial establishments. In 2001, nontraditional participants operated 2,538 facilities, accounting for 36.1% of total U.S. electric generation capacity (U.S. DOE, 2001a).

Nontraditional participants in the electric power industry are hereafter referred to as "***nonutilities***".

Figure B4-1 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 approximately 51%), but only represent 36% of total U.S. generating capacity. Investor-owned utilities operate the second largest number of facilities, 1,147, and account for 44.1% of total U.S. capacity.

Figure B4-1: Distribution of Facilities and Capacity by Ownership Type in 2001



Source: U.S. DOE, 2001a.

B4-2 DOMESTIC PRODUCTION

This section presents an overview of U.S. generating capacity and electricity generation. Section B4-2.1 provides data on capacity, and Section B4-2.2 provides data on generation. Section B4-2.3 presents an overview of the geographic distribution of generation plants and capacity.

B4-2.1 Generating Capacity

Utilities own and operate the majority of the generating capacity (65%) in the United States. Nonutilities owned only 35% of total capacity in 2001. Nonutility capacity has increased substantially in the past few years, as a result of both new plant construction by independent power producers and plant divestitures by investor-owned utilities. Nonutility capacity has increased 537% between 1991 and 2001, compared with a decrease in utility capacity of 21% over the same time period (U.S. DOE, 2003a).

Figure B4-2 shows the growth in utility and nonutility capacity from 1991 to 2001. The growth in nonutility capacity, combined with a decrease in utility capacity, has resulted in a modest growth in total generating capacity. The significant increase in nonutility capacity and decrease in utility capacity since 1997 is mainly attributable to utility plants being sold to nonutilities.

CAPACITY/CAPABILITY

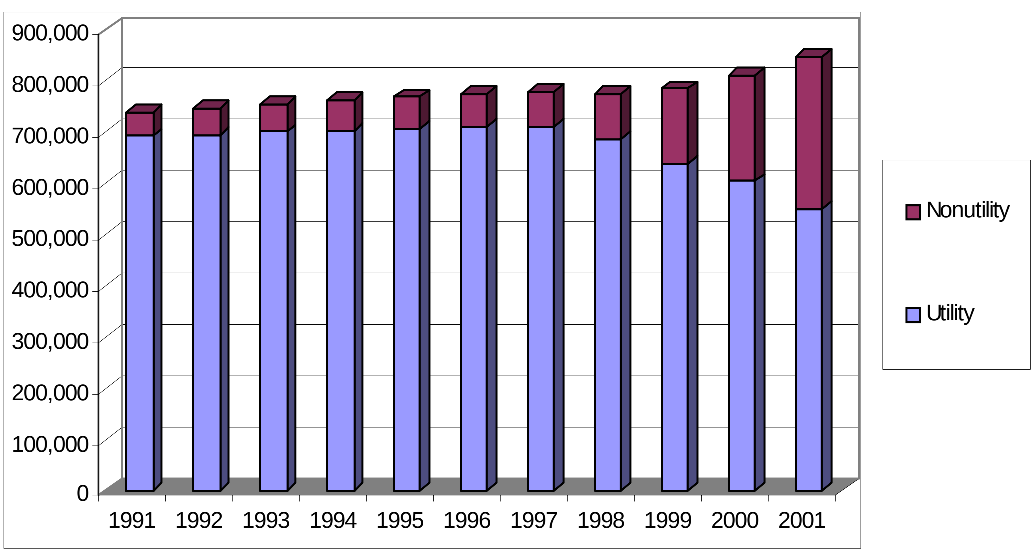
The rating of a generating unit is a measure of its ability to produce electricity. Generator ratings are expressed in megawatts (MW). Capacity and capability are the two common measures:

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

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

U.S. DOE, 2004

Figure B4-2: Net Summer Capacity, 1991 to 2001 (MW)



Source: U.S. DOE, 2003a.

B4-2.2 Electricity Generation

In 2001, total net electricity generation in the U.S. was 3,737 million MWh. Utility-owned plants accounted for 70% of this amount. Total net generation has increased by 22% over the 11 year period from 1991 to 2001. During this period, nonutilities increased their electricity generation by 345%. In comparison, generation by utilities decreased by 7% (U.S. DOE, 2003a). This trend is expected to continue with deregulation in the coming years, as more facilities are purchased and built by nonutility power producers.

Table B4-2 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% of net generation is lost during the transmission and distribution process.

U.S. DOE, 2004

Table B4-2: Net Generation by Energy Source and Ownership Type, 1991 to 2001 (million MWh)

Energy Source	Utilities			Nonutilities			Total		
	1991	2001	% Change	1991	2001	% Change	1991	2001	% Change
Coal	1,551	1,560	0.6%	39	344	771.4%	1,591	1,904	19.7%
Nuclear	613	534	-12.8%	-	235	n/a	613	769	25.5%
Natural Gas	264	264	0.1%	117	375	219.2%	382	639	67.5%
Hydropower	276	190	-31.0%	9	18	101.9%	284	208	-26.8%
Oil	111	79	-29.2%	8	46	454.7%	120	125	4.3%
Renewables[a]	10	2	-78.8%	59	76	29.3%	69	78	13.4%
Other Gases	-	-	-	11	9	-20.3%	11	9	-20.3%
Other[b]	-	-	-	5	5	-1.1%	5	5	-1.0%
Total	**2,825**	**2,630**	**-6.9%**	**249**	**1,107**	**344.9%**	**3,074**	**3,737**	**21.6%**

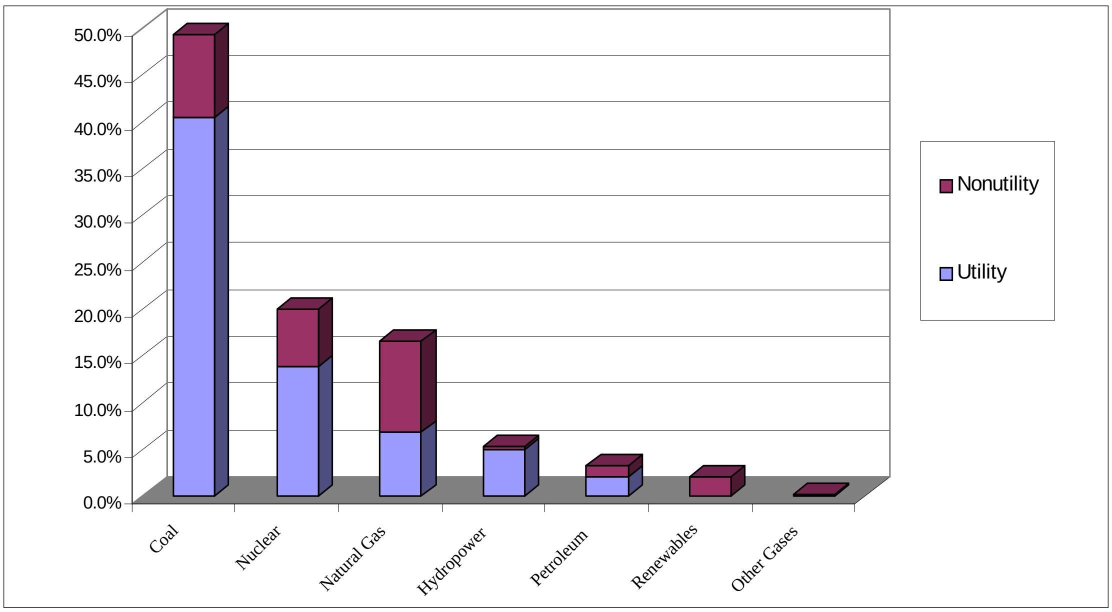
[a] Renewables include solar, wind, wood, biomass, and geothermal energy sources.
[b] Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies

Source: U.S. DOE, 2003a.

As shown in Table B4-2, natural gas generation grew the fastest among the fuel source categories, increasing by 68% between 1991 and 2001. Nuclear generation increased by 26%, while coal generation increased by 20%. Generation from renewable energy sources increased 13%. Hydropower, however, experienced a decline of 27%. 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. Coal generation was the fastest growing nonutility energy source, increasing 771% between 1991 and 2001. Generation from oil-fired facilities also increased substantially, by 455%.

Figure B4-3 shows total net generation for the U.S. by primary fuel source, for utilities and nonutilities. Electricity generation from coal-fired plants accounted for 51% of total 2001 generation. Electric utilities generated 82% (1,560 billion kWh) of the 1,904 billion kWh of electricity generated by coal-fired plants. This represents approximately 59% of total utility generation. The remaining 18% (344 billion kWh) of coal-fired generation were provided by nonutilities, accounting for 31% of total nonutility generation. The second largest source of electricity generation was nuclear power plants, accounting for 20% total utility generation and 21% of nonutility generation. Another significant source of electricity generation were gas-fired power plants, which accounted for 34% of nonutility generation and 17% of total generation.

Figure B4-3: Percentage of Electricity Generation by Primary Fuel Source in 2001



Source: U.S. DOE, 2003a.

The options evaluated for this proposed rule would affect facilities differently based on the fuel sources and prime movers used to generate electricity. As described in Section B4-1.2 above, only prime movers with a steam electric generating cycle use substantial amounts of cooling water and are potentially subject to Phase III regulation.

B4-2.3 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, but 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.

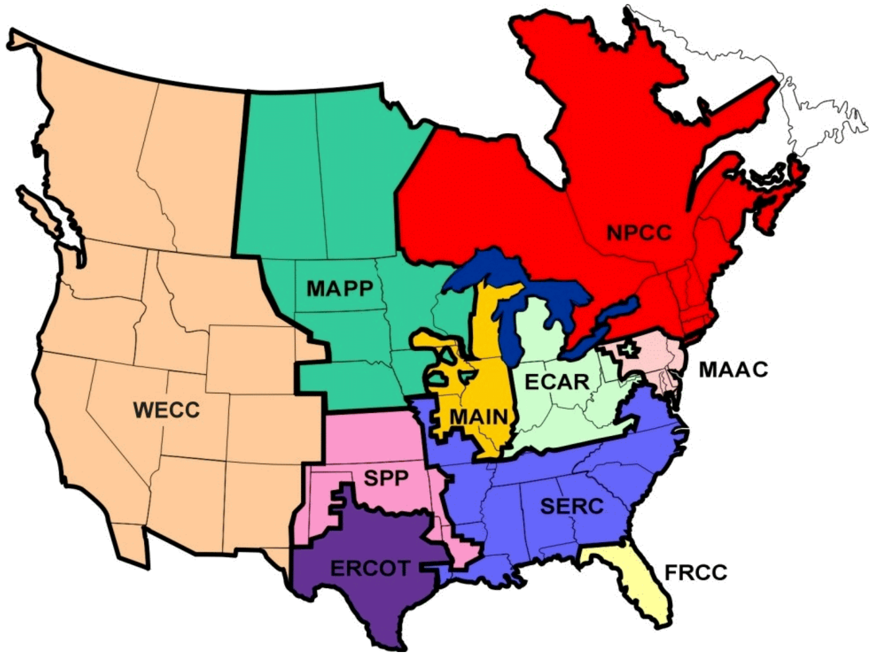
The North American Electric Reliability Council (NERC) is responsible for the overall reliability, planning, and coordination of the power grids. This voluntary organization was formed in 1968 by electric utilities, following a 1965 blackout in the Northeast. NERC is organized into ten regional councils 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. Historically, almost all wholesale trade was within the NERC regions, but utilities are expanding wholesale trade beyond those traditional boundaries (U.S. DOE, 2004).

Figure B4-4 below provides a map of the NERC regions, which include:

- ECAR – East Central Area Reliability Coordination Agreement
- ERCOT – Electric Reliability Council of Texas, Inc.
- FRCC – Florida Reliability Coordinating Council
- MAAC – Mid-Atlantic Area Council
- MAIN – Mid-America Interconnected Network, Inc.
- MAPP – Mid-Continent Area Power Pool
- NPCC – Northeast Power Coordinating Council
- SERC – Southeastern Electric Reliability Council
- SPP – Southwest Power Pool, Inc.
- WECC – Western Electricity Coordinating Council (formerly the Western Systems Coordinating Council)

Alaska and Hawaii are not shown in Figure B4-4. 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 B4-4: North American Electric Reliability Council (NERC) Regions



Source: NERC, 2004.

The options evaluated for Phase III existing facilities may affect plants located in different NERC regions differently. Economic characteristics of existing facilities affected by the analyzed options 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 an option on profitability, electricity prices, and other impact measures. However, as discussed in the appendix to *Chapter B5: Economic Impact Analysis for Electric Generators*, the three proposed options are estimated to have no impact on electricity prices in each region since none of the three options requires any power plants to comply with the national categorical requirements of the proposed rule.

Table B4-3 shows the distribution of all existing plants and capacity by NERC region. The table shows that 1,306 plants, equal to 26% of all facilities in the U.S., are located in the Western Electric Coordinating Council (WECC). However, these plants account for only 17% of total national capacity. Conversely, only 13% of generating plants are located in the Southeastern Electric Reliability Council (SERC), yet these plants account for 22% of total national capacity.

Table B4-3: Distribution of Existing Plants and Capacity by NERC Region in 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	128	2.6%	45,505	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%
WECC	1,306	26.0%	157,287	17.2%
Total	**5,019**	**100%**	**914,124**	**100%**

Source: U.S. DOE, 2001a.

B4-3 POWER PLANTS POTENTIALLY SUBJECT TO PHASE III 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 potentially subject to Phase III regulation. These are existing, steam electric power generating facilities that meet all of the following conditions:[4]

- 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 a National Pollutant Discharge Elimination System (NPDES) permit or are required to obtain one; and

- they have a design intake flow (DIF) of 2 million gallons per day (MGD) or greater but were not covered by the final Phase II rule (i.e., their DIF is at least 2 MGD but less than 50 MGD).

[4]Existing manufacturing facilities as well as new offshore oil and gas extraction facilities are also potentially subject to Phase III regulation. See chapters A1, B2, and C2 for more information on these industries.

Phase III regulation also covers substantial additions or modifications to operations undertaken at such facilities. While all electric generators that meet these criteria are potentially subject to Phase III regulation, this Economic Analysis (EA) focuses on 113 steam electric power generating facilities identified in EPA's 2000 Section 316(b) Industry Survey. These 113 facilities represent 117 facilities nation-wide.[5] The remainder of this chapter will refer to these potentially regulated facilities as "potential Phase III Electric Generators."

> **WATER USE BY STEAM ELECTRIC POWER PLANTS**
>
> Steam electric generating plants are the single largest industrial users of water in the United States. In 2000:
>
> - steam electric plants withdrew an estimated 195 billion gallons per day, accounting for 48% of total water withdrawals and 60% of total surface water withdrawals in the U.S.;
> - steam electric plants accounted for 96% of all saline withdrawals in the U.S.;
> - steam electric water withdrawals have increased by 3% between 1995 and 2000;
> - surface water accounted for more than 99% of steam electric water withdrawals;
> - approximately 69% of water intake by the electric power industry was from freshwater sources, 31% was from saline sources;
> - 91% of water withdrawal by power plants was used in once-through cooling systems; 9% was used in closed-loop cooling systems;
> - Illinois, Texas, and Tennessee combined accounted for 22% of steam electric freshwater withdrawals; California and Florida combined accounted for 41% of steam electric saline withdrawals;
> - the average amount of water used to produce one kilowatthour (kWh) decreased from 63 gallons in 1950 to 21 gallons in 2000.
>
> USGS, 2004

The following sections present a variety of physical, geographic, and ownership information about the potential Phase III Electric Generators. Topics discussed include:

- ***Ownership type:*** Section B4-3.1 discusses potential Phase III Electric Generators with respect to the electric utility entities that own them (referred to as "owner-utilities").

- ***Ownership size:*** Section B4-3.2 presents information on the size of the ultimate parent entities of potential Phase III Electric Generators.

- ***Plant size:*** Section B4-3.3 discusses the size distribution of potential Phase III Electric Generators by generation capacity.

- ***Geographic distribution:*** Section B4-3.4 discusses the distribution of potential Phase III Electric Generators by NERC region.

- ***Cooling Water Characteristics:*** Section B4-3.5 presents information on the type of waterbody from which potential Phase III Electric Generators draw their cooling water, the type of cooling system they operate, and the design intake flow of their cooling water intake structures.

B4-3.1 Ownership Type

The owners and operators of power plants can be divided into two broad ownership categories: traditional utilities and nonutilities. Utilities can further be classified as investor-owned utilities, publicly-owned utilities (municipalities, State authorities, and political subdivisions), cooperatives, and Federal electric utilities (see also Section B4-1.3 above). This classification is important because EPA has separately considered impacts on governments in its regulatory development (see *Chapter D2: UMRA Analysis* for the analysis of government impacts of the proposed rule).

[5] EPA applied sample weights to the 113 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 B4-4 shows the number of owner-utilities,[6] plants, and capacity by ownership type. Numbers are presented for the industry as a whole and the portion of the industry potentially subject to Phase III regulation. Overall, 2.9% of all owner-utilities, 2.3% of all plants, and 7.5% of all capacity is potentially subject to Phase III regulation. The table further shows that most potential Phase III Electric Generators (55) are owned by investor-owned utilities. An additional 34 potential Phase III Generators are owned by nonutilities. For all ownership types, less than 6% of all power plants are potentially subject to Phase III regulation. However, the percentage of capacity potentially subject to Phase III regulation is higher for State-owned power plants and cooperatives (26% and 20%, respectively) compared to the other ownership types.

Table B4-4: Utilities, Plants, and Capacity by Ownership Type in 2001[a]

Ownership Type	Owner-Utilities[b]			Plants			Capacity (MW)		
	Total[c]	With Potential Phase III Plants	% With Potential Phase III Plants	Total[c]	Potential Phase III[d]	% Potential Phase III	Total[c]	Potential Phase III[d]	% Potential Phase III
Investor-Owned	467	37	7.9%	1,148	55	4.8%	404,158	41,681	10.3%
Federal	8	1	12.5%	194	1	0.5%	69,402	2,409	3.5%
State	20	3	15.0%	85	4	4.7%	19,098	4,946	25.9%
Municipal	532	12	2.3%	785	13	1.7%	44,895	688	1.5%
Political Subdivision	46	0	0.0%	103	0	0.0%	18,012	0	0.0%
Cooperative	85	8	9.4%	166	9	5.4%	29,010	5,812	20.0%
Total Utility	**858**	**61**	**7.1%**	**2,481**	**83**	**3.3%**	**584,574**	**55,537**	**9.5%**
Nonutility[e]	**2,127**	**26**	**1.2%**	**2,538**	**34**	**1.4%**	**329,550**	**12,961**	**3.9%**
Total	**2,985**	**87**	**2.9%**	**5,019**	**117**	**2.3%**	**914,124**	**68,498**	**7.5%**

[a] Numbers may not add up to totals due to independent rounding.
[b] Owner-utilities are the direct owners of generating plants. They are not necessarily the ultimate parents of the plants. Numbers exclude utilities that engage solely in transmission and distribution.
[c] Information on the total number of owner-utilities 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 owner-utilities is not directly comparable to the information on total plants or total capacity.
[d] The number of potential Phase III Electric Generators and capacity was sample weighted to account for survey non-respondents.
[e] Total nonutilities from Form EIA-860; Form EIA-861 does not provide information for nonutilities.

Source: U.S. DOE, 2001a; U.S. DOE, 2001b; U.S. EPA, 2000; U.S. EPA Analysis, 2004.

B4-3.2 Ownership Size

In developing the proposed rule, EPA conducted an analysis of small entity impacts. The small entity analysis is conducted at the ultimate parent firm level which, for investor-owned utilities and nonutilities, is often different from the owner-utility level. EPA estimates that the 87 owner-utilities with plants potentially subject to Phase III regulation, presented in Table B4-4 above, are owned by 73 ultimate parent firms. Of these 73 entities, EPA

[6]Owner-utilities are the direct owners of generating plants. They are not necessarily the ultimate parents of the plants.

estimates that 13, or 17.8%, are small.[7] The size distribution varies considerably by ownership type: none of the potential Phase III investor-owned entities are small, compared to 75% of potential Phase III municipalities, 25% of potential Phase III cooperatives, and 9.5% of potential Phase III nonutilities. By definition, States and the Federal government are considered large parent entities. In general, traditional utility entities that own potential Phase III Electric Generators are larger than other entities in the industry. Of the 817 traditional utility parent entities in the industry, 412 entities, or 50.4%, are small. In contrast, only 21.2% of potential Phase III traditional utility entities are small. Overall, EPA estimates that 2.7% of all small utility parent entities own plants that are potentially subject to Phase III regulation. For nonutilities, the industry-wide number of small entities is not available.

For a detailed discussion of the identification and size determination of parent entities, see *Chapter D1: Regulatory Flexibility Analysis.* The chapter also documents how EPA considered the economic impacts on small entities when developing this regulation.

Table B4-5: Existing Parent Entities by Ownership Type and Size in 2001[a]

Ownership Type	Total Number of Parent Entities[b]				Total Number of Parent Entities That Own Potential Phase III ElectricGenerators				% of Small Entities That Own Potential Phase III Electric Generators
	Small	Large	Total	% Small	Small	Large	Total	% Small	
Investor-Owned	6	120	126	4.8%	-	28	28	0.0%	0.0%
Federal	-	8	8	0.0%	-	1	1	0.0%	0.0%
State	-	20	20	0.0%	-	3	3	0.0%	0.0%
Municipal	302	230	532	56.8%	9	34	12	75.0%	3.0%
Political Subdivision	37	9	46	80.4%	-	-	-	0.0%	0.0%
Cooperative	67	18	85	78.8%	2	6	8	25.0%	3.0%
Total Utility	**412**	**405**	**817**	**50.4%**	**11**	**41**	**52**	**21.2%**	**2.7%**
Nonutility[c]	**n/a**	**n/a**	**1,718**	**n/a**	**2**	**19**	**21**	**9.5%**	**n/a**
Total	**n/a**	**n/a**	**2,535**	**n/a**	**13**	**60**	**73**	**17.8%**	**n/a**

a Numbers may not add up to totals due to independent rounding.
b 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.
c Total nonutilities from Form EIA-860; Form EIA-861 does not provide data on nonutilities.

Source: U.S. DOE, 2001a; U.S. DOE, 2001b; U.S. EPA Analysis, 2004.

Table B4-6 presents the sample-weighted number of potential Phase III Electric Generators that are owned by small entities. The table shows that 14 of the 117 potential Phase III Electric Generators, or 12.2%, are owned by

[7] Small entities are defined as: (1) a small business according to the Small Business Administration (SBA) size standards; (2) a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of less than 50,000; or (3) a small organization that is a not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

small entities. Ten of the 14 potential Phase III Generators owned by small entities are municipalities, two are nonutilities, and two are rural electric cooperatives. There are no potential Phase III investor-owned utilities that are owned by a small entity. By definition, States and the Federal government are considered large parent entities.

Table B4-6: Potential Phase III Power Plants by Ownership Type and Size in 2001

Ownership Type	Number of Potential Phase III Facilties[a]			
	Small	Large	Total	% Small
Investor-Owned	0	55	55	0.0%
Federal	0	1	1	0.0%
State	0	4	4	0.0%
Municipal	10	3	13	76.9%
Cooperative	2	7	9	21.2%
Total Utility	**12**	**71**	**83**	**14.5%**
Nonutility	**2**	**32**	**34**	**6.4%**
Total	**14**	**103**	**117**	**12.2%**

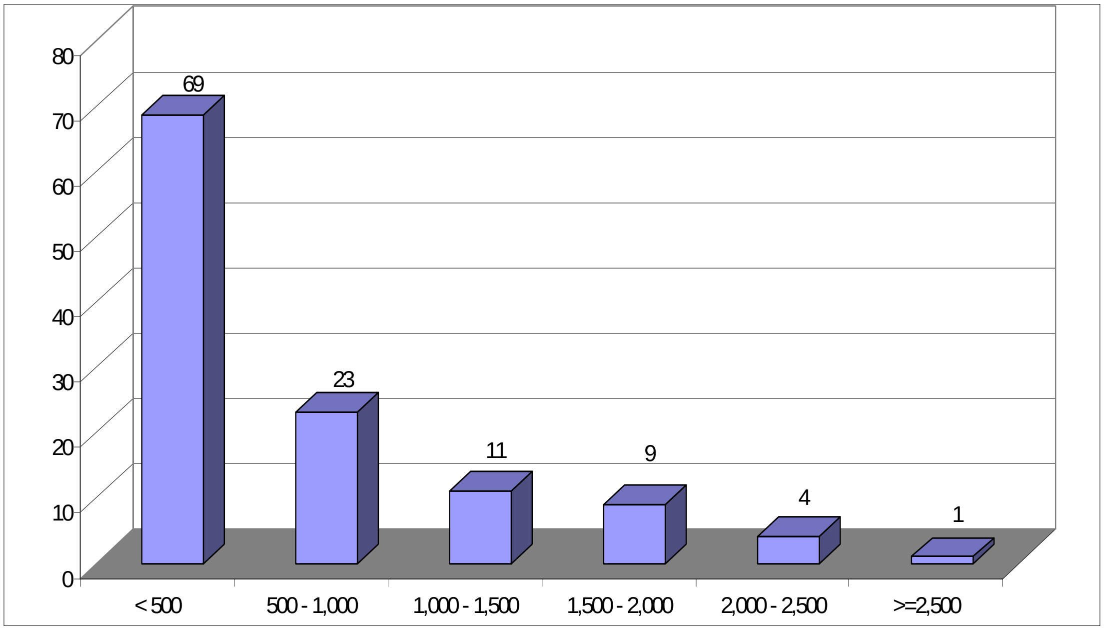
[a] The number of potential Phase III Electric Generators was sample weighted to account for survey non-respondents. Numbers may not add up to totals due to independent rounding.

Source: U.S. EPA analysis, 2004.

B4-3.3 Plant Size

EPA also analyzed the potential Phase III Electric Generators with respect to their generating capacity. The size of a Generator is important because it partly determines its need for cooling water and its importance in meeting electricity demand and reliability needs. Figure B4-5 shows that most potential Phase III Electric Generators have small generating capacities. Of the 117 potential Phase III facilities, 69 facilities (59%) have a capacity of less than 500 MW; 23 facilities (20%) have a capacity between 500 MW and 1,000 MW. Only five facilities have a capacity of greater than 2,000 MW, one of which has capacity of 2,500MW or greater. Of the 69 facilities with capacities less than 500 MW, 37 have a capacity of less than 100 MW, 17 have a capacity between 100 and 250 MW, and 15 have a capacity between 250 and 500 MW.

Figure B4-5: Number of Potential Phase III Electric Generators by Plant Size in 2001[a] (MW)



[a] The number of plants was sample weighted to account for survey non-respondents.

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

B4-3.4 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 in any one region, the higher the likelihood that there may be economic and/or system reliability impacts as a result of the regulation.

Table B4-7 shows the distribution of potential Phase III Electric Generators by NERC region. The table shows that there are only moderate differences between the regions both in terms of the number of potential Phase III Electric Generators and the percentage of all plants that they represent. Excluding Alaska and Hawaii, which have no generators potentially subject to Phase III regulation, the percentage of potential Phase III Electric Generators in each region ranges from 1% in the Western Electric Coordinating Council (WECC) and Northeast Power Coordinating Council (NPCC) to 5% in the East Central Area Reliability Coordination Agreement (ECAR). ECAR also has the highest absolute number of potential Phase III power plants with 22 facilities, followed by WECC with 18 facilities.

Table B4-7: Existing Plants by NERC Region in 2001

NERC Region	Total Number of Facilities	Potential Phase III Electric Generators[a]	
		Number	% of Total in Region
ASCC	124	-	0%
ECAR	448	22	5%
ERCOT	215	8	4%
FRCC	128	4	3%
HICC	34	-	0%
MAAC	246	10	4%
MAIN	412	6	2%
MAPP	445	10	2%
NPCC	718	11	1%
SERC	661	17	3%
SPP	282	11	4%
WECC	1,306	18	1%
Total	**5,019**	**117**	**2%**

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

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

B4-3.5 Cooling Water Characteristics

The main determinants of the compliance actions potentially required of Phase III Electric Generators include (1) the waterbody type from which they withdraw cooling water, (2) the type of cooling system they have in place in the baseline, and (3) the design intake flow of their cooling water intake structure. Table B4-8 shows that most of the potential Phase III Electric Generators draw water from a freshwater river or stream (87 plants or 75%). The next most frequent waterbody types are lakes or reservoirs (19 plants or 16%) and the Great Lakes (seven plants or 5%). The table also shows that most of the potential Phase III Electric Generators (86 plants or 74%) employ a recirculating cooling system.[8] Of the four plants that withdraw from an estuary, the most sensitive type of waterbody, two use a recirculating system. Plants with once-through cooling water systems withdraw between 70% and 98% more water than those with recirculating systems.

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

Table B4-8: Number of Potential Phase III Electric Generators by Water Body Type and Cooling System Type[a]

Waterbody Type	Cooling System Type						Total
	Recirculating		Once-Through		Combination/Other		
	No.	% of Total	No.	% of Total	No.	% of Total	
Estuary/ Tidal River	2	1.8%	2	1.7%	-	0.0%	**4**
Ocean	-	0.0%	-	0.0%	-	0.0%	**-**
Lake/ Reservoir	14	12.4%	4	3.7%	-	0.0%	**19**
Freshwater River/Stream	69	58.9%	14	11.6%	5	4.3%	**87**
Great Lake	1	0.9%	6	4.8%	-	0.0%	**7**
Total	**86**	**73.9%**	**26**	**21.8%**	**5**	**4.3%**	**117**

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

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

Table B4-9 presents the distribution of Electric Generators potentially subject to Phase III regulation by water body type and design intake flow (DIF) category. Many of the options evaluated by EPA differentiate compliance requirements based on the facility's DIF. Table B4-9 shows that more than half of the potential Phase III Electric Generators (66) have a DIF of less than 20 million gallons per day (MGD). Fifty-one, or 44%, of the facilities have a design intake flow of between 20 and 50 million MGD. None of the potential Phase III Electric Generators have a flow of 50 MGD or greater because those plants were regulated under the final Phase II rule (promulgated in July of 2004).

Table B4-9: Number of Potential Phase III Electric Generators by Water Body Type and Design Intake Flow Category[a]

Waterbody Type	Design Intake Flow[b]						Total
	< 20 MGD		20 - 50 MGD		50+ MGD		
	No.	% of Total	No.	% of Total	No.	% of Total	
Estuary/ Tidal River	4	3.5%	-	0.0%	-	0.0%	**4**
Ocean	-	0.0%	-	0.0%	-	0.0%	**-**
Lake/ Reservoir	12	10.7%	6	5.4%	-	0.0%	**19**
Freshwater River/Stream	47	39.9%	41	34.9%	-	0.0%	**87**
Great Lake	2	2.1%	4	3.5%	-	0.0%	**7**
Total	**66**	**56.2%**	**51**	**43.8%**	**-**	**0.0%**	**117**

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

[b] The three design intake flow (DIF) categories are defined as follows: "< 20 MGD" includes facilities that with a DIF of at least 2 MGD but less than 20 MGD; "20 - 50 MGD" includes facilities with a DIF of at least 20 MGD but less than 50 MGD; "50+ MGD" includes facilities with a DIF of at least 50 MGD.

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

B4-4 INDUSTRY OUTLOOK

This section discusses industry trends that are currently affecting the structure of the electric power industry and may therefore affect the magnitude of impacts from the Proposed Section 316(b) Rule for Phase III Facilities. 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 B4-4.1 discusses the current status of deregulation. Section B4-4.2 presents a summary of forecasts from the Annual Energy Outlook 2003.

B4-4.1 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.[9] The industry has traditionally been regulated based on the premise that the supply of electricity is a natural monopoly, where a single supplier could provide electric services at a lower total cost than could be provided by several competing suppliers. Today, the relationship between electricity consumers and suppliers is undergoing substantial change. Some States have implemented plans that will change the procurement and pricing of electricity significantly, and many more plan to do so during the first few years of the 21st century (Beamon, 1998).

a. Key changes in the industry's structure

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

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

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

- ***Electricity prices:*** Under the traditional system, State and Federal authorities regulated all aspects of utilities' business operations, including their prices. Electricity prices were determined administratively for each utility, based on the average cost of producing and delivering power to customers and a reasonable rate of return. As a result of deregulation, competitive market forces will set generation prices. Buyers and sellers of power will negotiate through power pools or one-on-one to set the price of electricity. As in all competitive markets, prices will reflect the interaction of supply and demand for electricity. During most time periods, the price of electricity will be set by the generating unit with the

[9]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).

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 February 2003, eighteen States had operating competitive retail electricity markets. Oregon did not have customers participating in the retail program, but nonresidential customers were allowed access (U.S. DOE, 2003b).

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).

B4-4.2 Energy Market Model Forecasts

This section discusses forecasts of electric energy supply, demand, and prices based on data and modeling by the Energy Information Administration (EIA) and presented in the *Annual Energy Outlook 2003* (U.S. DOE, 2003c). 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 Phase III rulemaking effort (see appendix to *Chapter B5: Economic Impact Analysis for Electric Generators*). 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% annually between 2000 and 2025. This growth is driven by an estimated 2.2% annual increase in the demand for electricity from the commercial sector associated with a projected annual growth in commercial floor space of 1.6%. EIA expects electricity demand from the industrial sector to increase by 1.7% annually, largely in response to an increase in industrial output of 2.6% per year. Residential demand is expected to increase by 1.6% annually over the same forecast period, due mostly to an increase in the number of U.S. households of 1.0% per year between 2000 and 2025.

b. Capacity retirements

The AEO2003 projects total fossil fuel-fired generation capacity to decline due to retirements. EIA forecasts that total fossil-steam capacity will decrease by an estimated 12% (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% (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% 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% 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 3% 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% to an estimated 50%. 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% in 2000 to an estimated 27% 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

Definitions are adapted from the following sources:

U.S. Department of Energy's *Electric Power Industry Overview*.
At: http://www.eia.doe.gov/cneaf/electricity/page/prim2/toc2.html

U.S. Department of Energy's *International Energy Annual 2002 - Glossary*.
At: http://www.eia.doe.gov/emeu/iea/glossary.html#W

U.S. Department of Energy's *Electric Power Annual Volume I - Glossary of Electricity Terms*.
At: http://www.eia.doe.gov/cneaf/electricity/epav1/glossary.html

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 (i.e., base load, intermediate load, and peak load units).

Combined-Cycle Unit: 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 delivery of electricity to retail customers (including homes, businesses, etc.).

Electricity Available to Consumers: Power available for sale to customers. Approximately 8% to 9% 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 in 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 or natural river current.

Intermediate load: Intermediate-load generating units meet system requirements that are greater than base load but less than peak load. Intermediate-load units are used during the transition between base load and peak load requirements.

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): 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. Nameplate capacity is expressed in ***watts*** or ***megawatts (MW)***.

Net Capability: 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.

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.

Other Prime Movers: Methods of power generation other than ***steam turbines***, ***combined-cycle units***, ***gas combustion turbines***, ***internal combustion engines***, and ***hydroelectric generating units***. Other prime movers include: geothermal, solar, wind, and biomass.

Peak load: A peakload generating unit, normally the least efficient of the three unit types (i.e., base load, intermediate load, and peak load units), is used to meet requirements during the periods of greatest, or peak, load on the system.

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.

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.

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.

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: Prudent costs incurred by a utility that may not be recoverable under market based retail competition. Examples are undepreciated generating facilities, deferred costs, and long-term contract costs.

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.

Watt: The electrical unit of power. The rate of energy transfer equivalent to one ampere flowing under the pressure of one volt at unity power factor.

Watthour (Wh): An electrical energy unit of measure equal to one watt of power supplied to, or taken from, an electric circuit steadily for one hour.

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Chapter B5: Economic Impact Analysis for Electric Generators

INTRODUCTION

CHAPTER CONTENTS

The design intake flow (DIF) applicability thresholds for national categorical requirements for the three proposed options for existing facilities are 50 MGD, 100 MGD, and 200 MGD, respectively. Since Electric Generators with a DIF of 50 MGD or greater were covered by the final Phase II rule, no Electric Generator would be subject to the national categorical requirements under any of the three proposed options; therefore there would be no compliance costs and no direct impacts on any Electric Generators, nor any indirect impacts on the Electric Generating Industry as a result of the proposed rule. However, Electric Generators would be regulated and incur compliance costs under several other options that were analyzed but ultimately not proposed by EPA. This chapter assesses the expected economic effect on Electric Generators of these other options. This chapter (1) describes the methodology used to estimate the private cost to Electric Generators potentially subject to Phase III regulation and presents summary cost statistics; (2) summarizes EPA's electricity market model analysis for Electric Generators potentially subject to Phase III regulation and the electric power industry as a whole; and (3) presents an additional assessment of the magnitude of compliance costs to Electric Generators, 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. The appendix to this chapter presents the detailed methodology and results of EPA's electricity market model analysis.

B5-1 ESTIMATION OF PRIVATE COMPLIANCE COSTS

This section summarizes EPA's analysis of private compliance costs that would be incurred by Electric Generators under various regulatory options that were considered but not proposed by EPA. The first subsection presents methodological components of estimating private costs that are unique to Electric Generators. For information on cost categories and cost methodologies that are common to all industry segments analyzed in developing the proposed requirements for Phase III existing facilities, please see *Chapter B1: Summary of Cost Categories and Key Analysis Elements for Existing Facilities*. The second subsection presents summary cost statistics for each analyzed option, including facility counts and compliance costs by cost category.

B5-1.1 Methodology

a. Development of Present Value and Annualized Costs

The estimation of compliance costs incurred by Electric Generators potentially subject to Phase III regulation starts with facility-level compliance cost estimates for each model facility developed in EPA's engineering analysis. EPA included the following compliance cost categories in this analysis: capital cost, annual operating and maintenance cost, administrative cost, and the loss of business income from potential shutdown of facilities during installation of compliance equipment. Of these cost categories, only operating and maintenance costs and certain administrative costs recur annually. The remaining costs occur only once at the beginning of compliance or in multi-year intervals over the period of the compliance analysis. Some of the impact analyses require combining the annually recurring and non-recurring costs into a single, annual equivalent value. For combining the annually recurring and non-recurring costs in this analysis, EPA calculated the annual equivalent cost of the non-recurring cost categories and added these *annualized* costs to the annually recurring operating and maintenance cost.

To derive the constant annual value of the non-annual costs, EPA calculated the present value as of the first year of compliance of each facility (for this analysis, assumed to be 2010 to 2014) and then annualized it, using a 7.0% pre-tax discount rate in both steps. The costs of compliance equipment were annualized over 10 years; initial permitting cost and the income loss from installation shutdown were annualized over 30 years; and repermitting costs were annualized over 5 years. EPA then added these annualized costs to annual O&M and administrative costs to derive each facility's total annual pre-tax cost of complying with each evaluated option.

For more information on the compliance cost components developed for this analysis and EPA's methodology of discounting, see Chapter B1 and the *Technical Development Document for the Proposed Section 316(b) Rule for Phase III Facilities* (TDD; U.S. EPA, 2004b).

b. Consideration of taxes

For understanding the economic impact of a regulation on facilities, the costs incurred by complying facilities are adjusted for taxes and calculated on an after-tax basis. The tax treatment of compliance outlays and income effects shifts part of these costs to the tax-paying public and reduces the actual cost to private, tax-paying businesses. For this reason, the after-tax costs of compliance are a more meaningful measure of the financial burden on complying facilities than the pre-tax costs. In analyzing and reporting the impact of compliance costs on private facilities, annualized costs are therefore calculated on an after-tax basis.

EPA used combined Federal and State tax rates, specific to the State of each facility, to estimate the annual after-tax cost of compliance. The total effective tax rate was calculated as follows:

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

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.[1] A reduction in tax liability was only applied to privately-owned facilities subject to income taxes, i.e., costs incurred by government-owned facilities and cooperatives are not adjusted for taxes, since these facilities are not subject to income taxes.

c. Monetary valuation of installation downtime

Installation of some of the compliance technologies considered for potential Phase III Electric Generators would require a one-time, temporary downtime of the facility's cooling water intake system. During the downtime period, the facility's cooling-water dependent operations would most likely be halted, with a potential loss of revenue and income from those operations. Accordingly, a key element of the cost to facilities in complying with the proposed standards for Phase III existing facilities is the loss in income from installation downtime. In the facility impact analyses for Electric Generators, this loss in income is accounted for as a loss in revenue offset by a reduction in variable costs in the affected business operations.

For the Electric Generating industry, EPA estimated facility-specific baseline revenue losses using 2008 revenue projections from the Integrated Planning Model (IPM®; U.S. EPA, 2002; U.S. EPA, 2003). IPM® revenues consist of energy revenues and capacity revenues (see discussion of the IPM® in the appendix to this chapter). One-time losses due to installation downtime were calculated by dividing each facility's annual revenue

[1] 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.

projections by 52 weeks and multiplying this value by the estimated average downtime (in weeks) of the facility's compliance technology.

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 costs include both fuel and other variable operating and maintenance costs. Similar to revenues, each facility's annual variable production costs were divided by 52 weeks and multiplied by the facility's estimated average downtime (in weeks).

The average cost of the technology installation 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 for electric generators:

$$\textit{Cost of Installation Downtime} = \textit{Revenue Loss} - \textit{Variable Production Costs}$$

where

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

This approach may overstate the cost of the installation downtime because it is based on average annual revenues and average 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.

d. Converting monetary values to current year dollar values

The various economic information used in the cost and impact analyses for potential Phase III Electric Generators were initially estimated in dollars of different years. To ensure consistent analyses and to present the estimated cost of regulatory compliance in approximately current values, EPA adjusted all dollar values to constant dollars of the year 2003 (average or mid-year, depending on availability) using an appropriate inflation adjustment index. For adjusting compliance costs, EPA used the ***Construction Cost Index (CCI)*** published by the Engineering News-Record (ENR, 2004; see Chapter B1 for index values used in this analysis).

The economic analysis for Electric Generators also uses revenue, cost, and electricity price data from the IPM® and electricity price data from the Annual Energy Outlook 2003 (U.S. DOE, 2003) and the Energy Information Administration's Form EIA-861 (U.S. DOE, 2001). These values were adjusted to year 2003 values using the Commodity Producer Price Index (PPI) for Industrial Electric Power (U.S. DOL, 2004). Table B5-1 below presents the PPI values used in this analysis.

Table B5-1: PPI Series for Industrial Electric Power

Year	Value	% Change
1997	130.8	
1998	130.0	-0.6%
1999	128.9	-0.8%
2000	131.5	2.0%
2001	141.1	7.3%
2002	139.9	-0.9%
2003	145.8	4.2%

Source: U.S. DOL, 2004.

B5-1.2 Summary Cost Statistics

a. Number of facilities with regulatory requirements

In conducting the economic impact analyses for Electric Generators, EPA first eliminated from the analysis those facilities estimated to be in severe financial distress independent of Phase III regulation. EPA judges these facilities, which are referred to as "baseline closures," to be at substantial risk of financial failure regardless of any additional financial burden that might result from the proposed rule or any of the other evaluated options. EPA identified three of the 117 potentially regulated Electric Generators as baseline closures. The identification of baseline closures is based on EPA's IPM® analyses. The IPM® considers a generator as a closure if the net present value of future operation is negative (see the appendix to this chapter).

After setting aside baseline closures, EPA determined which facilities would be subject to the national categorical requirements under each evaluated option. Facilities that do not meet the design intake flow (DIF)/source waterbody threshold for an option would be subject to permitting based on best professional judgment (BPJ). These facilities do not incur incremental costs under this rule and are therefore excluded from EPA's cost and economic impact analyses.

Table B5-2 below presents, for each evaluated option, the DIF applicability threshold, the number of Electric Generators potentially subject to Phase III regulation, the number of baseline closures, the number of Electric Generators subject to best professional judgment, and, by DIF Category, the number of Electric Generators subject to the national requirements.

Table B5-2: Phase III Electric Generator Counts for Evaluated Options

	DIF Applicability Threshold	Potentially Subject to Regulation	Baseline Closures	Subject to Best Professional Judgment	Subject to National Requirements			
					Total	DIF Category		
						2-20 MGD	20-50 MGD	50+ MGD
50 MGD All (proposed)	**50 MGD**	**117**	**3**	**114**	**-**	**-**	**-**	**-**
200 MGD All (proposed)	**200 MGD**	**117**	**3**	**114**	**-**	**-**	**-**	**-**
100 MGD Cert. (proposed)[a]	**100 MGD (C) BPJ (O)**	**117**	**3**	**114**	**-**	**-**	**-**	**-**
Option 3	20 MGD	117	3	63	51	-	51	-
Option 4[b]	20 MGD (C) 50 MGD (O)	117	3	110	4	-	4	-
Option 2	20 MGD	117	3	63	51	-	51	-
Option 1	20 MGD	117	3	63	51	-	51	-
Option 6	2 MGD	117	3	-	114	63	51	-

[a] The applicability threshold for the "100 MGD for Certain Waterbodies" option is 100 MGD for facilities withdrawing from certain waterbodies (estuaries/tidal rivers and oceans) and the Great Lakes. Facilities withdrawing from other waterbodies (freshwater rivers, and lakes/reservoirs) are subject to best professional judgment.

[b] The applicability threshold for Option 4 is 20 MGD for facilities withdrawing from certain waterbodies (estuaries/tidal rivers and oceans) and the Great Lakes and 50 MGD for facilities withdrawing from other waterbodies (freshwater rivers, and lakes/reservoirs).

Source: U.S. EPA, 2000.

b. Distribution of Electric Generators by NERC region and compliance year

Table B5-3 presents the distribution of the existing Electric Generators potentially subject to Phase III regulation (excluding baseline closures) by North American Electric Reliability Council (NERC) region and compliance year.[2] 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
- WECC – Western Electricity Coordinating Council

Table B5-3: Weighted Number of Phase III Electric Generating Facilities by NERC Region and Compliance Year[a]

NERC Region	2010	2011	2012	2013	2014	Total
ASCC	-	-	-	-	-	-
ECAR	4	2	4	4	7	22
ERCOT	2	-	2	3	1	8
FRCC	4	-	-	-	-	4
HI	-	-	-	-	-	-
MAAC	3	4	1	-	1	10
MAIN	-	1	1	3	1	6
MAPP	1	1	4	3	1	10
NPCC	3	1	1	2	3	11
SERC	10	2	-	-	3	16
SPP	1	2	4	3	1	11
WECC	6	2	4	3	1	16
Total	**35**	**15**	**22**	**21**	**20**	**114**

[a] Note that compliance years were estimated for this analysis. Actual compliance years might be different than stated in this table. Numbers only include facilities estimated to operate in the baseline.

Source: U.S. EPA Analysis, 2004.

c. Summary of compliance requirements

Table B5-4 shows estimated compliance requirements for each evaluated option, based on the performance standard each Electric Generator would need to meet (depending on each Generator's waterbody type, design intake flow, capacity utilization, and annual intake flow as a percent of source waterbody mean annual flow) and its baseline technologies in-place.

[2] For a detailed discussion of the NERC regions, see the appendix to this chapter. For a description of how EPA determined compliance years, see Chapter B1, Section B1-2.1 (Compliance Schedule).

Table B5-4: Number of Electric Generators by Compliance Requirement

Facility Compliance Requirement	Proposed Options	Option 3	Option 4	Option 2	Option 1	Option 6
Total Generators Potentially Subject to Regulation (excluding baseline closures)	**114**	114	114	114	114	114
Facilities Subject to Best Professional Judgment	**114**	63	110	63	63	-
Facilities Subject to National Categorical Requirements	-	51	4	51	51	114
No compliance requirement[a]	-	*39*	*2*	*38*	*36*	*94*
Impingement controls only	-	*12*	-	*11*	*10*	*14*
Impingement and entrainment controls	-	-	*2*	*2*	*5*	*6*

[a] These facilities meet compliance requirements in the baseline and thus would require no action to comply with the regulation.

Source: U.S. EPA Analysis, 2004.

d. Summary of estimated private compliance costs

Table B5-5 below presents, for each evaluated option, the annualized pre-tax and after-tax compliance costs estimated to be incurred by Electric Generators subject to the national categorical requirements.

Table B5-5: Private Compliance Costs for Electric Generators by Cost (annualized, 2003$)

	Number of Facilities Subject to National Require-ments	One-Time Costs				Recurring Costs			Total Annualized Costs
		Capital Technology	Down-time	Initial Permit Application	Pilot Study	O&M	Monitoring, Record Keeping & Reporting	Permit Renewal	
Pre-Tax Compliance Costs									
Proposed Options	-	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Option 3	51	$503,000	$0	$479,000	$0	$318,000	$328,000	$397,000	$2,025,000
Option 4	4	$168,000	$72,000	$250,000	$0	$70,000	$229,000	$183,000	$972,000
Option 2	51	$552,000	$72,000	$609,000	$0	$354,000	$492,000	$483,000	$2,562,000
Option 1	51	$608,000	$134,000	$625,000	$0	$419,000	$625,000	$490,000	$2,901,000
Option 6	114	$687,000	$151,000	$994,000	$0	$459,000	$872,000	$801,000	$3,963,000
After-Tax Compliance Costs									
Proposed Options	-	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Option 3	51	$393,000	$0	$411,000	$0	$247,000	$283,000	$338,000	$1,673,000
Option 4	4	$168,000	$72,000	$219,000	$0	$70,000	$203,000	$156,000	$888,000
Option 2	51	$443,000	$72,000	$510,000	$0	$282,000	$420,000	$399,000	$2,127,000
Option 1	51	$497,000	$120,000	$521,000	$0	$328,000	$519,000	$403,000	$2,388,000
Option 6	114	$558,000	$136,000	$791,000	$0	$358,000	$696,000	$630,000	$3,169,000

Source: U.S. EPA Analysis, 2004.

B5-2 SUMMARY OF ELECTRICITY MARKET MODEL ANALYSIS

EPA used an electricity market model, the IPM®, to assess potential economic and operational impacts of this proposal. As noted above, the three proposed options would not apply national requirements to any facilities in the Electric Generators segment; thus, the three proposed options have no effects to be considered in an IPM® analysis. Since conducting electricity market model analyses is time- and resource-intensive, EPA only analyzed one of the other options evaluated for this proposal. EPA chose to conduct an IPM® analysis of the most inclusive and most costly option, Option 6, to identify the upper bound of potential effects under any of the evaluated options.

EPA conducted impact analyses at the market level (by NERC region) and for facilities subject to the national requirements under Option 6. Analyzed characteristics include changes in electricity prices, capacity, generation, revenue, cost of generation, and income. These changes were identified by comparing outcomes in the post-compliance scenario ("Policy Case") with outcomes in the base case. Because of the interrelationships between the final Phase II rule (promulgated in July 2004) and Phase III regulation, EPA developed two base cases for this analysis:

- The first base case (referred to as "Base Case 1") models operational characteristics of the electricity market in the absence of any section 316(b) regulation (i.e., pre-Phase II regulation);
- The second base case (referred to as "Base Case 2") models operational characteristics of the electricity market including compliance costs of the final Phase II rule (but pre-Phase III regulation).

For the market-level analysis, EPA compared the Policy Case (after the implementation of Phase III compliance requirements) with Base Case 2 (including Phase II compliance costs). This comparison allows EPA to identify the incremental market-level effects of Phase III regulation, beyond the effects of Phase II regulation. In contrast, for the analysis of facilities subject to Phase III regulation, EPA compared the Policy Case with Base Case 1 (excluding Phase II compliance costs). This comparison was done to determine the "true" effect of Phase III regulation, net of any temporary effects that might be introduced as the result of the staggering of Phases II and III. Because Phase II facilities have to comply before Phase III facilities are projected to comply (on average by two years), Phase III facilities may experience a short-term competitive advantage during the time when Phase II facilities incur the new incremental section 316(b) compliance costs while Phase III facilities do not. The post-compliance economic performance of Phase III facilities should not be compared to this potential short-term improvement in operating characteristics but to their steady-state, pre-section 316(b) regulation economic condition.

EPA used the most current version of the IPM®, V.2.1.6 released in 2003, for the analysis in developing this proposal.[3] The 2003 version of the IPM® has been updated to include, among other things, compliance costs of the State Multi-Pollutant regulations and the New Source Review settlements, and updated costs for existing facilities, such as life extension costs.

A detailed discussion of the IPM®, the methodology used in this analysis, and the analysis results for Option 6 is presented in the appendix to this chapter.

B5-3 ADDITIONAL IMPACT ANALYSES

This section presents an additional assessment of the magnitude of Electric Generator compliance costs associated with the options evaluated for Phase III existing facilities. The analyses presented in this section include 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.

[3] The analysis of the final Phase II rule used a predecessor version, V.2.1.

B5-3.1 Cost-to-Revenue Analysis

The cost-to-revenue ratio is used to assess the magnitude of compliance costs relative to revenues. The cost-to-revenue ratio 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. This analysis uses impact thresholds of 0.5%, 1% and 3%.

a. Facility-level analysis

EPA received survey data for 113 Electric Generators potentially subject to Phase III regulation. EPA estimates that three of these 113 Electric Generators are baseline closures; these facilities are excluded from this analysis. For the remaining 110 facilities, EPA compared each facility's annualized after-tax compliance costs under each evaluated option to the facility's annual revenues. EPA used facility-specific baseline revenue projections from the IPM® for 2008 for this analysis. The IPM® did not provide revenues for two facilities because they are not included in the model. In addition, the IPM® projects that nine facilities will have zero revenues in the baseline. For the 11 facilities without IPM® revenues, EPA researched facility-specific electricity generation and firm-specific wholesale prices, as reported to the Energy Information Administration (EIA), to calculate the cost-to-revenue ratio. This research yielded information for nine of the 11 facilities; for the remaining two facilities, EIA revenues are either zero or negative. EPA then applied sample weights to the 110 facilities to account for non-sampled facilities and facilities that did not respond to the survey. The sample-weighted facility count, excluding baseline closures, is 114.

Table B5-6 below presents the results of the facility-level cost-to-revenue analysis for each evaluated option. The table presents (1) the total number of facilities subject to the national categorical requirements; (2) the number of facilities with a cost-to-revenue ratio of less than 0.5%, at least 0.5% but less than 1%, at least 1% but less than 3%, and at least 3%; and (3) the minimum and maximum ratios.

As previously noted, no Electric Generators are subject to the national requirements nor incur compliance costs under the three proposed options. Under the other evaluated options, between four and 114 Electric Generators are subject to the national requirements; the remaining facilities are subject to best professional judgment requirements and are excluded from this analysis. Table B5-6 shows that under most options, the majority of facilities would have a cost-to-revenue ratio of less than 0.5%. Under Option 6, the most inclusive and costly of the evaluated options, 10 facilities are estimated to have a ratio of between 1% and 3%, and 13 facilities are estimated to have a ratio of greater than 3%. The maximum ratio under Option 6 is 430%; the maximum ratios under the other evaluated options are 8.7% for Option 4 and 75.6% for Options 1, 2, and 3.

Table B5-6: Facility-Level Cost-to-Revenue Measure By Ownership Type

Option	Total Number of Facilities[a]	Number of Facilities with a Ratio of					Minimum Ratio	Maximum Ratio
		< 0.5%	0.5 to <1%	1 to <3%	>= 3%	No Rev.		
Proposed Options	-	-	-	-	-	-	**0.0%**	**0.0%**
Option 3	51	35	3	3	9	1	0.0%	75.6%
Option 4	4	1	-	1	2	-	0.0%	8.7%
Option 2	51	34	3	4	9	1	0.0%	75.6%
Option 1	51	33	1	7	9	1	0.0%	75.6%
Option 6	114	88	1	10	13	2	0.0%	430.4%

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

Source: IPM® analysis, V.2.1.6: model run for Section 316(b) base case, 2008, AEO electricity demand assumptions; U.S. EPA Analysis, 2004.

b. Firm-level analysis

The facility-level analysis presented 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 Phase III regulation. EPA therefore also analyzed the firm-level cost-to-revenue ratios of the evaluated options.

EPA first identified the domestic parent entity of each of the 110 surveyed, non-baseline closure Electric Generators potentially subject to Phase III regulation (for a detailed description of this analysis, see *Chapter D1: Regulatory Flexibility Analysis*). EPA determined that 72 unique domestic parent entities own these 110 facilities. EPA identified 18 entities that own more than one Electric Generator potentially subject to Phase III regulation. EPA obtained the sales revenues for each of the 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 each parent entity's aggregated after-tax compliance costs (summed over each facility owned by the parent entity and subject to the national requirements) to its total sales revenue.

Table B5-7 below presents the results of the firm-level cost-to-revenue measure. The table presents (1) the sample-weighted 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%, at least 0.5% but less than 1%, at least 1% but less than 3%, and at least 3%; and (4) the minimum and maximum ratios.

No Electric Generators are subject to the national requirements under the three proposed options. Under the other evaluated options, between four and 72 entities own Electric Generators subject to the national requirements; the remaining entities own facilities subject to best professional judgment requirements and are excluded from this analysis. EPA estimates that Phase III compliance costs would comprise a low percentage of firm-level revenues. Under all of the evaluated options, no more than one entity would experience a cost-to-revenue ratio of greater than 3%. Depending on the option, between one and five entities would have a ratio between 1% and 3%. The highest estimated cost-to-revenue ratio under any of the evaluated options is 3.39%.

Table B5-7: Firm-Level Cost-to-Revenue Measure by Entity Type

Option	Total Number of Facilities	Total Number of Entities	Number of Entities with a Ratio of				Minimum Ratio	Maximum Ratio
			<0.5%	0.5 to <1%	1 to <3%	>= 3%		
Proposed Options	-	-	-	-	-	-	**0.00%**	**0.00%**
Option 3	51	42	38	1	3	-	0.00%	2.65%
Option 4	4	4	2	-	1	1	0.00%	3.39%
Option 2	51	42	38	-	3	1	0.00%	3.39%
Option 1	51	42	37	-	4	1	0.00%	3.39%
Option 6	114	72	66	-	5	1	0.00%	3.39%

Source: U.S. EPA Analysis, 2004.

B5.3-2 Cost Per Household Analysis

EPA also conducted an analysis that evaluates the potential cost per household, if Phase III facilities were able to pass compliance costs on to their customers. This analysis estimates the average compliance cost per household for each North American Electric Reliability Council (NERC) region, using data on residential consumers from the 2001 Form EIA-861.[4]

EPA calculated the average annual cost per household for each evaluated option by dividing the total pre-tax compliance cost of all regulated facilities in a NERC region by the total number of households in that region. This analysis assumes that Electric Generators pass costs on to consumers, on a dollar-to-dollar basis, and that there will be no reduction in electricity consumption by the consumers in response to price increases. EPA also used the conservative assumption that residential consumers bear the full burden of compliance costs; no other customer groups (e.g., commercial or industrial consumers) are assumed to bear any of the compliance costs.

Table B5-8 presents the annualized pre-tax compliance costs, by NERC region, for each evaluated option. Table B5-9 shows the number of households in each NERC region, and the estimated annual compliance cost per household. No Electric Generators would incur compliance costs under the three proposed options. The highest estimated annual cost per household, under any option and in any region, is $0.12 in the Mid-Continent Area Power Pool (MAPP) under Options 1 and 6. Under all other options and in all other regions, the estimated annual cost per household is lower.

Table B5-8: Annualized Pre-Tax Compliance Cost by NERC Region (2003$)

NERC Region[a]	Proposed Options	Option 3	Option 4	Option 2	Option 1	Option 6
ASCC	**$0**	$0	$0	$0	$0	$0
ECAR	**$0**	$256,000	$387,000	$504,000	$642,000	$917,000
ERCOT	**$0**	$7,000	$0	$7,000	$7,000	$18,000
FRCC	**$0**	$2,000	$0	$2,000	$2,000	$10,000
HI	**$0**	$0	$0	$0	$0	$0
MAAC	**$0**	$8,000	$0	$8,000	$8,000	$22,000
MAIN	**$0**	$400,000	$376,000	$482,000	$482,000	$687,000
MAPP	**$0**	$540,000	$0	$540,000	$603,000	$612,000
NPCC	**$0**	$417,000	$209,000	$623,000	$623,000	$1,109,000
SERC	**$0**	$14,000	$0	$14,000	$14,000	$36,000
SPP	**$0**	$275,000	$0	$275,000	$275,000	$289,000
WECC	**$0**	$107,000	$0	$107,000	$246,000	$262,000
U.S.	**$0**	**$2,025,000**	**$972,000**	**$2,562,000**	**$2,901,000**	**$3,963,000**

[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; WECC – Western Electricity Coordinating Council.

Source: U.S. DOE, 2001; U.S. EPA Analysis, 2004.

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

Table B5-9: Annual Compliance Cost per Residential Consumer by NERC Region (2001)

NERC Region[a]	Number of Households (2001)	Annual Compliance Cost/ Residential Consumer (2003 $)					
		Proposed Options	**Option 3**	**Option 4**	**Option 2**	**Option 1**	**Option 6**
ASCC	234,646	**$0.00**	$0.00	$0.00	$0.00	$0.00	$0.00
ECAR	15,698,205	**$0.00**	$0.02	$0.02	$0.03	$0.04	$0.06
ERCOT	7,309,073	**$0.00**	$0.00	$0.00	$0.00	$0.00	$0.00
FRCC	6,885,280	**$0.00**	$0.00	$0.00	$0.00	$0.00	$0.00
HI	351,229	**$0.00**	$0.00	$0.00	$0.00	$0.00	$0.00
MAAC	8,921,106	**$0.00**	$0.00	$0.00	$0.00	$0.00	$0.00
MAIN	8,366,132	**$0.00**	$0.05	$0.04	$0.06	$0.06	$0.08
MAPP	4,933,221	**$0.00**	$0.11	$0.00	$0.11	$0.12	$0.12
NPCC	12,676,283	**$0.00**	$0.03	$0.02	$0.05	$0.05	$0.09
SERC	20,550,922	**$0.00**	$0.00	$0.00	$0.00	$0.00	$0.00
SPP	5,002,020	**$0.00**	$0.06	$0.00	$0.06	$0.06	$0.06
WECC	23,085,962	**$0.00**	$0.00	$0.00	$0.00	$0.01	$0.01
U.S.	**114,014,079**	**$0.00**	**$0.02**	**$0.01**	**$0.02**	**$0.03**	**$0.03**

[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; WECC – Western Electricity Coordinating Council.

Source: U.S. DOE, 2001; U.S. EPA Analysis, 2004.

B5-3.3 Electricity Price Analysis

EPA also considered potential effects of Phase III regulation on electricity prices. EPA used three data inputs in this analysis: (1) total pre-tax compliance cost incurred by facilities subject to the national requirements; (2) total electricity sales projected for 2007 (the year the proposed rule would take effect), based on the Annual Energy Outlook (AEO) 2003; and (3) projected prices for 2007 by consumer type (residential, commercial, industrial, and transportation), also from the AEO 2003. All three data elements were calculated by NERC region.

Table B5-10 shows total projected electricity sales (in MWh) for 2007 and the average compliance cost per kilowatt hour (KWh) for each evaluated option, by NERC region. The average cost per kilowatt hour for each option was estimated by dividing the annualized pre-tax compliance costs for each NERC region (presented in Table B5-8 above) by the region’s total electricity sales. No Electric Generating facilities would incur compliance costs under the three proposed options. For all other evaluated options, the average cost ranges from no additional cost per KWh sales to a maximum of 0.0004 cents per KWh sales. The U.S. average is estimated to be 0.0001 additional cents per KWh sales or less under all options.

Table B5-10: Compliance Cost per KWh of Sales by NERC Region

NERC Region[a]	Total Electricity Sales (MWh; 2001)	Annualized Pre-Tax Compliance Cost (Cents / KWh Sales)					
		Proposed Options	**Option 3**	**Option 4**	**Option 2**	**Option 1**	**Option 6**
ASCC	---	**¢0.0000**	¢0.0000	¢0.0000	¢0.0000	¢0.0000	¢0.0000
ECAR	570,807,007	**¢0.0000**	¢0.0000	*¢0.0001*	*¢0.0001*	*¢0.0001*	*¢0.0002*
ERCOT	297,949,799	**¢0.0000**	¢0.0000	¢0.0000	¢0.0000	¢0.0000	¢0.0000
FRCC	208,035,233	**¢0.0000**	¢0.0000	¢0.0000	¢0.0000	¢0.0000	¢0.0000
HI	---	**¢0.0000**	¢0.0000	¢0.0000	¢0.0000	¢0.0000	¢0.0000
MAAC	280,251,282	**¢0.0000**	¢0.0000	¢0.0000	¢0.0000	¢0.0000	¢0.0000
MAIN	255,762,939	**¢0.0000**	*¢0.0002*	*¢0.0001*	*¢0.0002*	*¢0.0002*	*¢0.0003*
MAPP	172,704,269	**¢0.0000**	*¢0.0003*	¢0.0000	*¢0.0003*	*¢0.0003*	*¢0.0004*
NPCC	282,686,981	**¢0.0000**	*¢0.0001*	*¢0.0001*	*¢0.0002*	*¢0.0002*	*¢0.0004*
SERC	853,386,597	**¢0.0000**	¢0.0000	¢0.0000	¢0.0000	¢0.0000	¢0.0000
SPP	191,778,000	**¢0.0000**	*¢0.0001*	¢0.0000	*¢0.0001*	*¢0.0001*	*¢0.0002*
WECC	259,401,428	**¢0.0000**	¢0.0000	¢0.0000	¢0.0000	*¢0.0001*	*¢0.0001*
U.S.	**3,845,085,938**	**¢0.0000**	***¢0.0001***	**¢0.0000**	***¢0.0001***	***¢0.0001***	***¢0.0001***

[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; WECC – Western Electricity Coordinating Council.
The Annual Energy Outlook does not include ASCC and HI.

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

To determine potential effects on electricity prices as a result of compliance with the evaluated options, EPA compared the compliance cost per KWh of sales, presented in Table B5-10 above, to projected baseline electricity prices for different consumer types (projections for 2007).

Table B5-11 below presents the estimated percentage changes in baseline electricity prices for Option 6, the most inclusive and most costly of the evaluated options. These results therefore represent the upper bound of potential electricity price effects under any of the evaluated options. Rounded to the nearest 100th of a percent, the largest estimated percentage increases for any consumer type and in any region under Option 6 is 0.01%. For all other options, the resulting percentage increases in electricity prices would be less than, or equal to, those estimated for Option 6. Overall, EPA concludes that the compliance costs for none of the evaluated options would have an effect on electricity prices.

This analysis assumes that Electric 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.

Table B5-11: Estimated Price Increase as a Percentage of 2007 Prices by Consumer Type and NERC Region – Option 6 (All costs and prices in cents per kilowatt hour; 2003$)

Region	Annualized Pre-Tax Compliance Cost (Cents / KWh Sales)	Residential		Commercial		Industrial		Transportation		All Sectors Average	
	Opt. 6	Price	% Change	Price	% Change	Price	% Change	Price	% Change	Price	% Change
ECAR	*0.0002*	6.72	0.00%	5.95	0.00%	4.15	0.00%	5.65	0.00%	5.51	0.00%
ERCOT	0.0000	8.30	0.00%	7.74	0.00%	5.08	0.00%	6.94	0.00%	7.22	0.00%
FRCC	0.0000	8.37	0.00%	7.16	0.00%	5.33	0.00%	7.32	0.00%	7.65	0.00%
MAAC	0.0000	7.48	0.00%	5.88	0.00%	5.35	0.00%	6.16	0.00%	6.34	0.00%
MAIN	*0.0003*	7.60	0.00%	6.10	0.00%	4.18	*0.01%*	6.12	0.00%	6.01	0.00%
MAPP	*0.0004*	6.91	*0.01%*	5.80	*0.01%*	3.99	*0.01%*	5.74	*0.01%*	5.53	*0.01%*
NPCC	*0.0004*	10.64	0.00%	7.85	*0.01%*	5.47	*0.01%*	8.40	0.00%	8.37	0.00%
SERC	0.0000	7.42	0.00%	6.55	0.00%	4.16	0.00%	6.29	0.00%	6.16	0.00%
SPP	*0.0002*	7.18	0.00%	6.03	0.00%	4.06	0.00%	5.76	0.00%	5.91	0.00%
WECC	*0.0001*	6.55	0.00%	5.90	0.00%	3.38	0.00%	5.67	0.00%	5.22	0.00%
U.S.	***0.0001***	**7.86**	**0.00%**	**6.87**	**0.00%**	**4.43**	**0.00%**	**6.71**	**0.00%**	**6.54**	**0.00%**

Source: U.S. EPA Analysis, 2004.

B5-4 UNCERTAINTIES AND LIMITATIONS

❖ ***Estimation of Private Compliance Costs***

EPA's estimates of the compliance costs associated with the options evaluated in developing the proposed rule are subject to limitations because of uncertainties about the number and characteristics of Electric Generators that would potentially be subject to Phase III regulation under each option. Projecting the number of facilities that meet the design intake flow applicability thresholds 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 of data reported by the facilities in their surveys and with the projected technologies for the STQ facilities. The estimated total compliance costs for the Electric Generating industry may be over- or understated if the projected number of Phase III existing facilities subject to the national categorical requirements is incorrect or if the characteristics of the facilities are different from those assumed in the analysis.

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 would 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 evaluated options. 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.

There is also uncertainty associated with the estimates of facility revenues. Facility revenues are projected revenues from the IPM®. The IPM® is a forward looking model that simulates generator dispatch based on numerous assumptions about future conditions, including future fuel prices, electricity demand, new capacity additions, heat rates, etc. Changing these assumptions might affect the projected facility revenues and the estimated cost of installation downtime for Electric Generators.

❖ ***Electricity Market Model Analysis***

Uncertainties and limitations associated with EPA's IPM® analysis are documented in the appendix to this chapter.

❖ ***Additional Impact Analyses***

There is uncertainty associated with EPA's estimates of potential cost per household and electricity price changes. As noted in the sections above, EPA's analyses are based on the assumption that Electric Generators would be able to pass on 100% of their compliance costs to their customers. For the cost per household analysis, EPA assumed that all costs would be passed on to all residential customers in the region. The results of this analysis might differ if less than 100% of compliance costs could be passed on, or if only a subset of residential consumers in a region bore the passed-on costs. For the electricity price analysis, EPA assumed that all costs would be spread evenly among all customers. Again, the results of this analysis might differ if less than 100% of compliance costs could be passed on, or if the different customer groups bore different shares of compliance costs. However, in both analyses, the two uncertainty factors would change results in opposite directions; it is therefore unclear whether EPA's analyses might overstate or understate actual impacts. In addition, the impacts of both analyses are very minor; therefore, it is unlikely that EPA's findings would change, even if one or more of EPA's assumptions were incorrect.

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Appendix 1 to Chapter B5: Electricity Market Model Analysis

INTRODUCTION

This appendix presents EPA's analysis of impacts on Electric Generators potentially subject to Phase III regulation and to the Electric Generating Industry as a whole. While only a subset of facilities in the electric power generation industry would be subject to Phase III regulation under any option evaluated for this proposal, interdependencies within the electric power market, might result in indirect impacts throughout the industry. Direct impacts on plants subject to an evaluated option 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 Phase III regulation, 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.

APPENDIX CONTENTS

Under the proposed options, the minimum applicability threshold for national categorical requirements is 50 MGD or greater. Since Electric Generators with design intake flows of 50 MGD or greater were covered by Phase II regulation, no Phase III Generator would be subject to the national categorical requirements under any of the proposed options; therefore there would be no direct impacts on any Electric Generators nor any indirect impacts on the Electric Generating Industry as a result of the proposed rule. However, some of the other options evaluated by EPA would impose compliance costs on Electric Generators. This chapter presents an analysis of the potential effects of Option 6, the most costly option considered by EPA, and the option with the highest potential impacts. Option 6 would impose national categorical requirements on all facilities with a DIF of 2 MGD or greater.

EPA used ICF Consulting's Integrated Planning Model (IPM®), an integrated energy market model, to conduct the economic analyses supporting this rule.[1] 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 Option 6: (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");[2] and (2) potential economic impacts on facilities potentially subject to Phase III regulation.

Option 6 was evaluated under the unadjusted electricity demand from the Annual Energy Outlook (AEO) 2003. Section B5A-3 presents the results of the IPM® analysis for Option 6.

[1] The IPM® was also used for the Phase II Rule. At the time of the Phase II proposal EPA evaluated several models suitable for analysis of environmental policies that affect the electric power industry. For a full discussion of the various models EPA considered, refer to section B3-1 and Appendix B in Chapter B3 of the *Economics and Benefits Analysis for the Final Section 316(b) Phase II Existing Facilities Rule* (U.S. EPA, 2004a).

[2] Please refer to *Chapter D3: Other Administrative Requirements* for a discussion of this analysis.

B5A-1 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 Rule were developed, the latest EPA specification of the U.S. power market, "EPA Base Case 2000," was based on IPM® Version 2.1 (U.S. EPA, 2002). In July 2003, a new version of the model, Version 2.1.6, was released (U.S. EPA, 2003). The Phase III proposal analyses utilize the specifications for the new "EPA Base Case 2003". A summary table of model updates is presented in section B5A-4.

B5A-1.1 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.[3]

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.

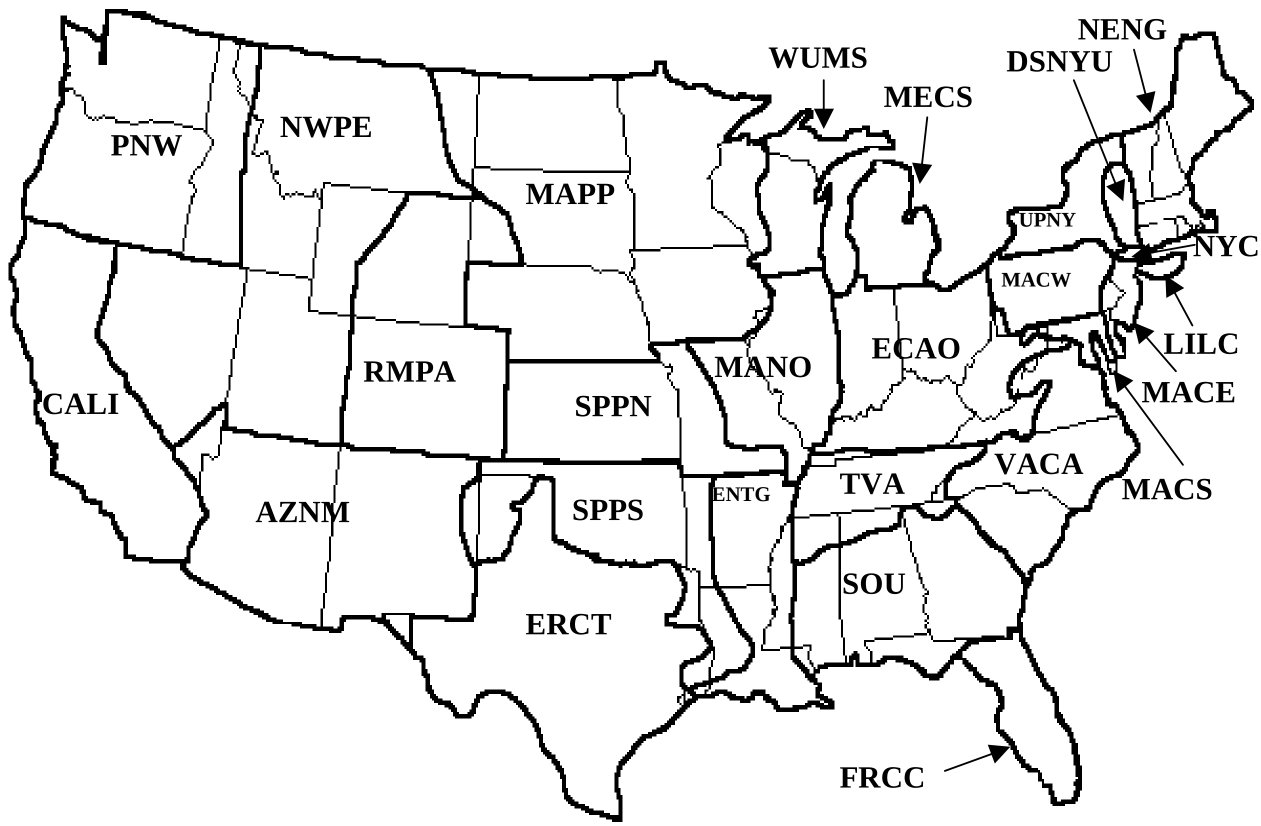
[3] EPA used the IPM® to forecast operational changes, including changes in capacity, generation, revenues, electricity prices, and plant closures, resulting from the rule. In other policy analyses, the IPM® is generally also used to determine the compliance response for each model facility. This process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

The number and aggregation scheme of model plants can be adjusted to meet the specific needs of each analysis. The EPA Base Case 2003 contains 1,703 model plants.

c. IPM® regions

The IPM® divides the U.S. electric power market into 26 regions in the contiguous U.S. It does not include generators located in Alaska or Hawaii. The 26 regions map into North American Reliability Council (NERC) regions and sub-regions. The IPM® models electric demand, generation, transmission, and distribution within each region and across the transmission grid that connects regions. For the analyses presented in this chapter, IPM® regions were aggregated back into NERC regions. Figure B5A-1 provides a map of the regions included in the IPM®. Table B5A-1 presents the crosswalk between NERC regions and IPM® regions.

Figure B5A-1: Regional Representation of U.S. Power System as Modeled in IPM®



Source: U.S. EPA, 2002.

Table B5A-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
WECC – Western Electricity 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 the Phase II analysis: 2008, 2010, and 2013, and has chosen to retain them for the Phase III analysis.[4,5]

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 B5A-2 below identifies the model run years specified for the analysis of Phase III options and the calendar years mapped to each.

[4] 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. For a discussion explaining the reasons for the selected model run years refer to section B3-2.1d of the *Economics and Benefits Analysis for the Final Section 316(b) Phase II Existing Facilities Rule* (U.S. EPA, 2004a).

[5] EPA estimates that Phase III facilities would comply between 2010 and 2014. For the analyses using the IPM® only, EPA modified this assumption and used compliance years of 2008 through 2012 by subtracting two years from the estimated compliance year of each facility. This modification allowed EPA to analyze the output for 2013 as the year when all facilities are in compliance.

Table B5A-2: Model Run Year Mapping

Run Year	Mapped Years
2008	2005-2009
2010	2010-2012
2013	2013-2015
2020	2016-2022
2026	2023-2030

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

B5A-1.2 Specifications for the Section 316(b) Analysis

The analysis for section 316(b) rulemaking required changes in the original specification of the IPM®. 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 and non-steam electric generators at facilities subject to the Phase II and Phase III rules 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 1,703 to 2,342.

- ***Use of Different Model Run Years:*** The original specification of the IPM®'s EPA Base Case 2003 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) rulemaking effort. 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 B5A-1.1.d above). The change in run years and run year mappings are summarized below.

Table B5A-3: Modification of Model Run Years

EPA Base Case 2003 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 2003 and the Section 316(b) Base Case.

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

- Base case total production costs (capital, O&M, and fuel) using the revised section 316(b) specifications are lower by 0.1% in 2010 and 2020.

- Early retirements of base case oil and gas steam capacity and coal capacity under the section 316(b) specifications are higher by 3,192 megawatt (MW) and 383 MW in 2010 and 2020, respectively.
- The change in model specifications resulted in virtually no change in base case coal and gas use in 2010 and 2020.

B5A-1.3 Model Inputs

Compliance costs and compliance-related capacity reductions are the primary model inputs in the analysis of section 316(b) rulemaking. EPA determined compliance costs for each of the 113 facilities potentially subject to Phase III regulation and 534 facilities subject to the Phase II regulation and modeled by the IPM®.[6] 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 *Technical Development Document for the Proposed Section 316(b) Rule for Phase III Facilities*; U.S. EPA, 2004b).

- ***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 after-tax payments using a discount rate of 5.34% for medium risk investments and 6.74%for high risk investments, and a capital charge rate of 12% for medium risk investments and 13.4% for high risk investments 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. High risk investments include Integrated Gasification Combined Cycle (IGCC) and repowerings-to- IGCC.[7]

- ***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.

- ***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

[6] Two of the 113 facilities potentially subject to Phase III regulation and nine of the 543 facilities subject to the Phase II rule are either not modeled in the IPM® or do not have steam-electric generators: one Phase III facility is out-of-service; one Phase II facility is retired; five facilities, one Phase III and four Phase II, are on-site generators that do not provide electricity to the grid; three Phase II facilities are in Hawaii and one Phase II facility is in Alaska, neither of which is represented in the IPM®.

[7] 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, after-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 after-tax return on equity.

average over the years that are mapped into each model run year.[8] Estimated generator downtimes due to construction and/or installation range from two to eleven weeks (see also *Chapter B1: Summary of Cost Categories and Key Analysis Elements for Existing Facilities*).

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 645 modeled section 316(b) Phase II and Phase III facilities were identified using data from the IPM®.
- Generator-specific design intake flows were obtained from Form EIA-767 (1998 and 2000).[9]
- 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 2003 cross-walk between boilers and generators.

B5A-1.4 Model Outputs

The IPM® generates a series of outputs on different levels of aggregation (boiler, model plant, region, and nation). The economic analysis for Option 6 used a subset of the available IPM® output. For each model run 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.[10]
- ***Early Retirements*** – The IPM® models economic closures as a result of negative net present value of future operation.[11] Under the Phase II analysis, all power plants that retired after the compliance year continued to carry the compliance costs after retirement. This modeling assumption has been changed for the Phase III analysis such that power plants with a compliance year in the 2005, 2006, or 2007 model run years, if endogenously retired by the model in the 2008 run year, will not carry the cost of the compliance decision over their retired life.

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[8] 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.

[9] 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 41 of 111 Phase III modeled facilities and 60 of the 534 Phase II modeled facilities.

[10] 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.

[11] Under the Phase II analysis nuclear plants were evaluated for economic viability at the end of their license term. Nuclear units that, at age 30, did not make a major maintenance investment, were provided with a 10-year life extension, if they were economically viable. These same units could subsequently undertake a 20-year re-licensing option at age 40. Nuclear units that already had made a maintenance investment were provided with a 20-year re-licensing option at age 40, if they were economically viable. All nuclear units were ultimately retired at age 60. Nuclear power plant retirements are no longer endogenous in the 2003 IPM®, and are now consistent with AEO2003. All other nuclear plants are assumed to remain operating over the modeling time horizon.

- ***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.

B5A-2 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 Option 6. EPA developed impact measures at two analytic levels: (1) the market as a whole, including all facilities and (2) the subset of facilities potentially subject to Phase III regulation. Both analyses were conducted by NERC region. The following subsections describe the impact measures used for the two levels of analysis.

B5A-2.1 Market-level Impact Measures

The market-level analysis evaluates regional changes as a result of Option 6. 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 Phase III regulation. In the short term, temporary plant shut-downs for the installation of Phase III compliance technologies may lead to reductions in available capacity.[12] When analyzing changes in

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

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 analyzed option. 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 III regulation. In the long term, electricity prices may change as a result of increased production costs of the potential Phase III 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 III 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 III 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 B5A-1.4 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.

B5A-2.2 Facility-level Impact Measures (Potential Phase III Facilities Only)

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

a. Potential Phase III facilities as a group

The analysis of the potential Phase III facilities as a group is largely similar to the market-level analysis described in Section B5A-2.1 above, except that the base case and policy option totals only include the economic activities of the 111 potentially regulated Phase III 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 potential Phase III 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 potential Phase III facilities:

- ***(1) Changes in available capacity:*** This measure considers the capacity available at the 111 potentially regulated Phase III 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 III compliance technologies may lead to reductions in available capacity.[13] Under this measure, EPA also analyzed **regulatory 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 regulatory closure facilities and closure capacity are analyzed.

- ***(2) Changes in generation:*** This measure considers the generation at the 111 potential Phase III 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 111 potential Phase III facilities. For some 316(b) facilities, Phase III 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 111 potential Phase III facilities and includes both energy revenues and capacity revenues (see definition in section B5A-1.4 above). A change in revenues could be the result of a change in generation and/or the price of electricity. For some 316(b) facilities, Phase III 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 111 Phase III 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.

b. Individual Phase III facilities

[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.

To assess potential distributional impacts among individual Phase III facilities, EPA analyzed facility-specific changes to a number of key measures. For each measure, EPA determined the number of potential Phase III facilities that experience an increase or a reduction, respectively, within three ranges: 1% or less, 1 to 3%, and more than 3%. 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% 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.

B5A-3 ANALYSIS RESULTS FOR OPTION 6

The remainder of this section presents the results of the economic impact analysis of Option 6 for the ten NERC regions modeled by the IPM®. Analyzed characteristics include changes in electricity prices, capacity, generation, revenue, cost of generation, and income. These changes were identified by comparing outcomes in the post-compliance scenario with outcomes in the base case. Because of the interrelationships between the final Phase II rule (promulgated in July 2004) and regulation of potential Phase III facilities, EPA developed two base cases for this analysis: the first base case (referred to as Base Case 1) models operational characteristics of the electricity market in the absence of any section 316(b) rulemaking (i.e., pre-Phase II regulation); the second base case (referred to as Base Case 2) models operational characteristics of the electricity market including compliance costs of the final Phase II rule (but pre-Phase III regulation). Results are presented at the market level and the Phase III facility level.

For the market-level analysis of Option 6, EPA compared the post-compliance scenario (after the implementation of Phase III compliance requirements) with Base Case 2 (including Phase II compliance costs). This comparison allows EPA to identify the incremental market-level effects of Phase III requirements, beyond the effects of Phase II regulation. In contrast, for the analysis of facilities subject to Phase III regulation, EPA compared the post-compliance scenario with Base Case 1 (excluding Phase II compliance costs). This comparison was done to determine the "true" effect of Phase III regulation, net of any temporary effects that might be introduced as the result of the staggering of the three section 316(b) phases. Because Phase II facilities have to comply before Phase III facilities (on average by two years), Phase III facilities may experience a short-term competitive advantage during the time when Phase II facilities incur section 316(b) compliance costs while Phase III facilities do not. The post-compliance economic performance of Phase III facilities should not be compared to this potential short-term improvement in operating characteristics but to their steady-state, pre-section 316(b) rulemaking economic condition.

The following subsections present the market-level analysis (including all facilities, by NERC region) and the facility-level analysis (including analyses of the in-scope Phase III facilities as a group and of individual Phase III facilities). The results are presented using data from model run year 2013. It should be noted that the results presented in this section are based on Option 6; EPA did not conduct an IPM® analysis for the other options considered for this proposal. Since Option 6 is the most inclusive and costly of any of the considered options, the results represent the upper bound estimate of potential economic impacts as a result of proposed Phase III regulation. And, as noted above, none of the three proposed options would apply national categorical requirements to any electric generating facilities; thus the proposed options have no effects to be considered in an IPM® analysis.

B5A-3.1 Market Analysis for 2013

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 potentially subject to Phase III regulation and facilities that are not subject to Phase III regulation.

Table B5A-4 presents the market-level impact measures discussed in section B5A-2.1 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 Base Case 2 and Option 6, the absolute difference between the two cases, and the percentage difference.

Table B5A-4: Market-Level Impacts of Option 6 (by NERC Region; 2013)

Economic Measures	Base Case 2	Option 6	Difference	% Change
National Totals				
(1) Total Domestic Capacity (MW)	992,564	992,549	(15)	0.0%
(1a) Existing	944,254	944,168	(86)	0.0%
(1b) New Additions	38,766	39,008	241	0.6%
(1c) Repowering Additions	9,544	9,373	(171)	(1.8)%
(1d) Closures	23,213	23,386	173	0.7%
(2a) Energy Prices ($2003/MWh)	n/a	n/a	n/a	n/a
(2b) Capacity Prices ($2003/KW/yr)	n/a	n/a	n/a	n/a
(3) Generation (GWh)	4,592,198	4,592,191	(7)	0.0%
(4) Revenues (Millions; $2003)	$181,098	$181,026	($72)	0.0%
(5) Costs (Millions; $2003)	$112,839	$112,863	$23	0.0%
(5a) Fuel Cost	$64,060	$64,075	$14	0.0%
(5b) Variable O&M	$8,393	$8,394	$1	0.0%
(5c) Fixed O&M	$35,689	$35,692	$3	0.0%
(5d) Capital Cost	$4,696	$4,702	$5	0.1%
(6) Pre-Tax Income (Millions; $2003)	$68,259	$68,164	($95)	(0.1)%
(7) Variable Production Costs ($/MWh)	$15.78	$15.78	$0.00	0.0%
East Central Area Reliability Coordination Agreement (ECAR)				
(1) Total Domestic Capacity (MW)	129,375	129,381	6	0.0%
(1a) Existing	127,266	127,264	(3)	0.0%
(1b) New Additions	2,109	2,117	8	0.4%
(1c) Repowering Additions	0	0	0	0.0%
(1d) Closures	1,699	1,703	4	0.2%
(2a) Energy Prices ($2003/MWh)	$28.81	$28.81	$0.01	0.0%
(2b) Capacity Prices ($2003/KW/yr)	$59.50	$59.55	$0.05	0.1%
(3) Generation (GWh)	711,535	711,438	(97)	0.0%
(4) Revenues (Millions; $2003)	$28,304	$28,313	$9	0.0%

Table B5A-4: Market-Level Impacts of Option 6 (by NERC Region; 2013)

Economic Measures	Base Case 2	Option 6	Difference	% Change
(5) Costs (Millions; $2003)	$15,091	$15,086	($4)	0.0%
(5a) Fuel Cost	$8,423	$8,423	$0	0.0%
(5b) Variable O&M	$1,703	$1,702	($1)	(0.1)%
(5c) Fixed O&M	$4,471	$4,471	$0	0.0%
(5d) Capital Cost	$494	$491	($3)	(0.6)%
(6) Pre-Tax Income (Millions; $2003)	$13,213	$13,226	$14	0.1%
(7) Variable Production Costs ($/MWh)	$14.23	$14.23	$0.00	0.0%
Electric Reliability Council of Texas (ERCOT)				
(1) Total Domestic Capacity (MW)	88,456	88,456	0	0.0%
(1a) Existing	80,603	80,722	119	0.1%
(1b) New Additions	6,622	6,966	345	5.2%
(1c) Repowering Additions	1,231	768	(463)	(37.6)%
(1d) Closures	178	291	113	63.4%
(2a) Energy Prices ($2003/MWh)	$39.84	$41.91	$2.07	5.2%
(2b) Capacity Prices ($2003/KW/yr)	$14.69	$5.48	($9.21)	(62.7)%
(3) Generation (GWh)	343,397	343,397	0	0.0%
(4) Revenues (Millions; $2003)	$14,972	$14,873	($98)	(0.7)%
(5) Costs (Millions; $2003)	$10,490	$10,504	$14	0.1%
(5a) Fuel Cost	$6,834	$6,844	$10	0.1%
(5b) Variable O&M	$698	$700	$2	0.2%
(5c) Fixed O&M	$2,309	$2,311	$2	0.1%
(5d) Capital Cost	$649	$650	$1	0.1%
(6) Pre-Tax Income (Millions; $2003)	$4,481	$4,369	($112)	(2.5)%
(7) Variable Production Costs ($/MWh)	$21.93	$21.97	$0.03	0.2%
Florida Reliability Coordinating Council (FRCC)				
(1) Total Domestic Capacity (MW)	56,655	56,655	0	0.0%
(1a) Existing	52,822	52,676	(146)	(0.3)%
(1b) New Additions	1,463	1,316	(146)	(10.0)%
(1c) Repowering Additions	2,370	2,662	292	12.3%
(1d) Closures	145	145	0	0.0%
(2a) Energy Prices ($2003/MWh)	$34.46	$34.43	($0.04)	(0.1)%
(2b) Capacity Prices ($2003/KW/yr)	$50.55	$50.82	$0.28	0.5%
(3) Generation (GWh)	231,180	231,180	0	0.0%
(4) Revenues (Millions; $2003)	$10,831	$10,838	$7	0.1%
(5) Costs (Millions; $2003)	$7,173	$7,177	$4	0.1%
(5a) Fuel Cost	$4,633	$4,634	$1	0.0%
(5b) Variable O&M	$432	$432	$0	0.0%
(5c) Fixed O&M	$1,870	$1,868	($1)	(0.1)%
(5d) Capital Cost	$238	$243	$5	2.1%
(6) Pre-Tax Income (Millions; $2003)	$3,658	$3,661	$3	0.1%

Table B5A-4: Market-Level Impacts of Option 6 (by NERC Region; 2013)

Economic Measures	Base Case 2	Option 6	Difference	% Change
(7) Variable Production Costs ($/MWh)	$21.91	$21.91	$0.00	0.0%
Mid-Atlantic Area Council (MAAC)				
(1) Total Domestic Capacity (MW)	70,973	70,973	0	0.0%
(1a) Existing	68,977	68,977	0	0.0%
(1b) New Additions	1,997	1,997	0	0.0%
(1c) Repowering Additions	0	0	0	0.0%
(1d) Closures	949	949	0	0.0%
(2a) Energy Prices ($2003/MWh)	$31.55	$31.56	$0.01	0.0%
(2b) Capacity Prices ($2003/KW/yr)	$44.06	$44.06	$0.01	0.0%
(3) Generation (GWh)	314,261	314,253	(8)	0.0%
(4) Revenues (Millions; $2003)	$13,039	$13,044	$5	0.0%
(5) Costs (Millions; $2003)	$8,131	$8,131	$0	0.0%
(5a) Fuel Cost	$3,744	$3,744	$0	0.0%
(5b) Variable O&M	$537	$537	$0	0.0%
(5c) Fixed O&M	$3,619	$3,619	$0	0.0%
(5d) Capital Cost	$230	$230	$0	0.0%
(6) Pre-Tax Income (Millions; $2003)	$4,908	$4,913	$5	0.1%
(7) Variable Production Costs ($/MWh)	$13.62	$13.62	$0.00	0.0%
Mid-America Interconnected Network (MAIN)				
(1) Total Domestic Capacity (MW)	69,770	69,770	0	0.0%
(1a) Existing	67,013	67,013	0	0.0%
(1b) New Additions	2,757	2,757	0	0.0%
(1c) Repowering Additions	0	0	0	0.0%
(1d) Closures	0	0	0	0.0%
(2a) Energy Prices ($2003/MWh)	$27.09	$27.09	$0.00	0.0%
(2b) Capacity Prices ($2003/KW/yr)	$51.01	$51.05	$0.04	0.1%
(3) Generation (GWh)	332,292	332,359	68	0.0%
(4) Revenues (Millions; $2003)	$12,556	$12,561	$5	0.0%
(5) Costs (Millions; $2003)	$7,690	$7,692	$2	0.0%
(5a) Fuel Cost	$3,405	$3,406	$1	0.0%
(5b) Variable O&M	$544	$544	$0	0.0%
(5c) Fixed O&M	$3,424	$3,425	$1	0.0%
(5d) Capital Cost	$317	$317	$0	0.0%
(6) Pre-Tax Income (Millions; $2003)	$4,866	$4,870	$3	0.1%
(7) Variable Production Costs ($/MWh)	$11.88	$11.88	$0.00	0.0%
Mid-Continent Area Power Pool (MAPP)				
(1) Total Domestic Capacity (MW)	37,368	37,368	0	0.0%
(1a) Existing	37,336	37,336	0	0.0%
(1b) New Additions	32	32	0	0.0%
(1c) Repowering Additions	0	0	0	0.0%

Table B5A-4: Market-Level Impacts of Option 6 (by NERC Region; 2013)

Economic Measures	Base Case 2	Option 6	Difference	% Change
(1d) Closures	0	0	0	0.0%
(2a) Energy Prices ($2003/MWh)	$25.58	$25.58	$0.00	0.0%
(2b) Capacity Prices ($2003/KW/yr)	$40.39	$40.42	$0.03	0.1%
(3) Generation (GWh)	190,058	190,058	0	0.0%
(4) Revenues (Millions; $2003)	$6,404	$6,406	$2	0.0%
(5) Costs (Millions; $2003)	$3,884	$3,885	$1	0.0%
(5a) Fuel Cost	$1,968	$1,968	$0	0.0%
(5b) Variable O&M	$370	$370	$0	0.0%
(5c) Fixed O&M	$1,541	$1,542	$1	0.0%
(5d) Capital Cost	$5	$5	$0	0.0%
(6) Pre-Tax Income (Millions; $2003)	$2,520	$2,521	$1	0.0%
(7) Variable Production Costs ($/MWh)	$12.30	$12.30	$0.00	0.0%
Northeast Power Coordinating Council (NPCC)				
(1) Total Domestic Capacity (MW)	77,994	77,982	(12)	0.0%
(1a) Existing	74,198	74,151	(47)	(0.1)%
(1b) New Additions	3,586	3,621	35	1.0%
(1c) Repowering Additions	210	209	0	(0.1)%
(1d) Closures	3,531	3,578	47	1.3%
(2a) Energy Prices ($2003/MWh)	$34.95	$34.95	$0.00	0.0%
(2b) Capacity Prices ($2003/KW/yr)	$30.21	$30.21	$0.00	0.0%
(3) Generation (GWh)	306,579	306,608	30	0.0%
(4) Revenues (Millions; $2003)	$13,053	$13,054	$1	0.0%
(5) Costs (Millions; $2003)	$9,535	$9,538	$3	0.0%
(5a) Fuel Cost	$5,248	$5,248	$0	0.0%
(5b) Variable O&M	$439	$439	$0	0.0%
(5c) Fixed O&M	$3,426	$3,426	$0	0.0%
(5d) Capital Cost	$422	$424	$3	0.6%
(6) Pre-Tax Income (Millions; $2003)	$3,518	$3,516	($2)	0.0%
(7) Variable Production Costs ($/MWh)	$18.55	$18.55	$0.00	0.0%
Southeastern Electric Reliability Council (SERC)				
(1) Total Domestic Capacity (MW)	218,915	218,915	0	0.0%
(1a) Existing	207,416	207,416	0	0.0%
(1b) New Additions	11,499	11,499	0	0.0%
(1c) Repowering Additions	0	0	0	0.0%
(1d) Closures	8,824	8,824	0	0.0%
(2a) Energy Prices ($2003/MWh)	$30.48	$30.47	$0.00	0.0%
(2b) Capacity Prices ($2003/KW/yr)	$47.76	$47.77	$0.01	0.0%
(3) Generation (Gwh)	1,065,456	1,065,456	0	0.0%
(4) Revenues (Millions; $2003)	$42,915	$42,912	($3)	0.0%
(5) Costs (Millions; $2003)	$25,995	$25,997	$2	0.0%

Table B5A-4: Market-Level Impacts of Option 6 (by NERC Region; 2013)

Economic Measures	Base Case 2	Option 6	Difference	% Change
(5a) Fuel Cost	$14,586	$14,588	$2	0.0%
(5b) Variable O&M	$1,839	$1,839	$0	0.0%
(5c) Fixed O&M	$8,468	$8,468	$0	0.0%
(5d) Capital Cost	$1,102	$1,102	$0	0.0%
(6) Pre-Tax Income (Millions; $2003)	$16,921	$16,915	($6)	0.0%
(7) Variable Production Costs ($/MWh)	$15.42	$15.42	$0.00	0.0%
Southwest Power Pool (SPP)				
(1) Total Domestic Capacity (MW)	57,806	57,797	(9)	0.0%
(1a) Existing	57,806	57,797	(9)	0.0%
(1b) New Additions	0	0	0	0.0%
(1c) Repowering Additions	0	0	0	0.0%
(1d) Closures	179	188	9	5.0%
(2a) Energy Prices ($2003/Mwh)	$28.05	$28.05	$0.00	0.0%
(2b) Capacity Prices ($2003/KW/yr)	$13.96	$13.97	$0.01	0.1%
(3) Generation (GWh)	239,392	239,392	0	0.0%
(4) Revenues (Millions; $2003)	$7,520	$7,521	$1	0.0%
(5) Costs (Millions; $2003)	$5,505	$5,506	$1	0.0%
(5a) Fuel Cost	$3,582	$3,583	$1	0.0%
(5b) Variable O&M	$472	$472	$0	(0.1)%
(5c) Fixed O&M	$1,444	$1,443	$0	0.0%
(5d) Capital Cost	$8	$8	$0	(1.9)%
(6) Pre-Tax Income (Millions; $2003)	$2,015	$2,015	$0	0.0%
(7) Variable Production Costs ($/MWh)	$16.93	$16.94	$0.00	0.0%
Western Electricity Coordinating Council (WECC)				
(1) Total Domestic Capacity (MW)	185,252	185,252	0	0.0%
(1a) Existing	170,817	170,817	0	0.0%
(1b) New Additions	8,702	8,702	0	0.0%
(1c) Repowering Additions	5,733	5,733	0	0.0%
(1d) Closures	7,708	7,708	0	0.0%
(2a) Energy Prices ($2003/MWh)	$32.62	$32.62	$0.00	0.0%
(2b) Capacity Prices ($2003/KW/yr)	$20.37	$20.37	$0.00	0.0%
(3) Generation (GWh)	858,050	858,050	0	0.0%
(4) Revenues (Millions; $2003)	$31,504	$31,504	$0	0.0%
(5) Costs (Millions; $2003)	$19,346	$19,347	$1	0.0%
(5a) Fuel Cost	$11,638	$11,638	$0	0.0%
(5b) Variable O&M	$1,360	$1,360	$0	0.0%
(5c) Fixed O&M	$5,116	$5,117	$1	0.0%
(5d) Capital Cost	$1,232	$1,232	$0	0.0%
(6) Pre-Tax Income (Millions; $2003)	$12,158	$12,157	($1)	0.0%
(7) Variable Production Costs ($/MWh)	$15.15	$15.15	$0.00	0.0%

Table B5A-4: Market-Level Impacts of Option 6 (by NERC Region; 2013)

Economic Measures	Base Case 2	Option 6	Difference	% Change
Source: IPM® Analysis: Model runs for Section 316(b) Base Case 2 and Option 6.				

Summary of Market Results at the National Level.
The results presented in Table B5A-4 show that capacity closures are estimated to increase by 173 MW, which represents 0.7% of total baseline capacity. Repowering additions are estimated to experience a net decrease of 171 MW or 1.8%. However, an estimated increase of 241 MW in new additions would offset the lost capacity. Total costs of electricity generation would not change, but capital costs are estimated to rise by 0.1%. All other measures are estimated to change by less than 1%.

Summary of Market Results at the Regional Level. At the regional level, Option 6 is estimated to result in the following changes:

- **ERCOT** is estimated to experience the most notable changes in electricity prices, repowering additions, new capacity, and closures among the ten NERC regions. Energy prices increase by $2.07/MWh, which represents a 5.2% increase. Capacity prices decrease by $9.21/KW/year, or approximately 63%. This is partially due to the increase in energy prices, which allows facilities to bid their undispatched capacity at a lower price. This may also be, in part, due to an increase of 345 MW of new additions. The increased new additions are offset by a large decrease in repowering additions (463 MW, or 37.6%). Capacity closures increase by 113 MW. However, these closures occur in facilities that do not fall under Phase III regulation. While not subject to regulation these generators retire because there is a decrease in the capacity price they are able to receive for existing capacity. As a result of lower capacity prices, pre-tax income is also estimated to decrease in ERCOT (2.5%). All other measures are predicted to change by less than 1%.

- **FRCC** is the only region estimated to experience a reduction in new additions (146 MW, or 10%). It is also estimated to lose 146 MW of existing capacity. A projected 292 MW increase in repowering, however, would completely offset these reductions. FRCC is estimated to have an increase in capacity prices and a decrease in energy prices. However, both changes are less than 1%. All other measures are also estimated to change by less than 1%.

- **SPP** and **NPCC** are the only regions that are estimated to experience an increase in post-compliance capacity closures. In SPP, the 9 MW increase in closures (5% of Base Case 2 capacity) is due to the partial retirement of a potential Phase III facility. In NPCC, the 47 MW increase in closures (1.3% of Base Case 2 capacity) is the result of combination of partial facility closures and an avoided partial facility closure. Specifically, three facilities (two potential Phase III and one Phase II) retire 73 MW of capacity while one potential Phase III facility opts to keep 26 MW of capacity on-line which was retired under the baseline. The net result of these changes is a 47 MW increase in closures. There are no additional changes in capacity in SPP. However, NPCC is estimated to have an additional 35 MW of new additions. The changes in all other measures are less than 1%.

- **ECAR** is estimated to have the largest decrease in generation (97 GWh). However, this decrease is negligible in comparison to total base case generation (less than 0.1%). Overall capacity (6 MW), new additions (8 MW), and closures (4 MW, all of which is potential Phase III capacity) increase slightly. Capacity prices also increase slightly (0.1%), as does pre-tax income (0.1%). All other measures do not change.

- **MAAC, MAIN, MAPP, SERC, and, WECC** are not estimated to have any significant impacts for any of the measures analyzed. There are no changes in capacity for each region; there is no new or repowered capacity, and there are no additional closures as a result of Option 6. MAAC is estimated to have a slight increase in energy prices. Energy prices remain constant in each of the other regions. Each region except

WECC experiences a slight increase in capacity prices (on average 0.1%). Generation, revenue, and costs are not expected to significantly change for any region. MAAC and MAIN are estimated to have a 0.1% increase in pre-tax income.

B5A-3.2 Analysis of Potential Phase III Facilities for 2013

This section presents the results of the IPM® analysis for facilities that are potentially subject to Phase III regulation and that are modeled by the IPM®. Four of the 111 potential Phase III facilities are closures in Base Case 1, and five facilities are closures under Option 6. These facilities are not represented in the results described in this section.

EPA used the IPM® results from model run year 2013 to analyze impacts on potential Phase III facilities at two levels: (1) changes in the economic and operational characteristics of the potential Phase III facilities as a group and (2) changes to individual facilities within the group of potential Phase III facilities.

a. Potential Phase III facilities as a group

This section presents the analysis of the impacts of Option 6 on the potential Phase III facilities as a group. This analysis is similar to the market-level analysis described above but is limited to facilities subject to the national requirements of Option 6. Table B5A-5 presents the impact measures for the group of potential Phase III facilities discussed in section B5A-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 1 and Option 6, the absolute difference between the two cases, and the percentage difference.

Two points should be kept in mind when interpreting these results:

- The percentage changes are calculated relative to baseline values of potential Phase III facilities in each region. In some regions, very few facilities are potentially subject to Phase III regulation. If these percentage changes were calculated relative to the total for all electric power facilities in each region, the observed percentage changes would be much smaller.
- The post-compliance scenario reflects compliance costs of both Phase II and Phase III regulation, while the base case reflects conditions before either Phase II or Phase III regulation. While Phase II compliance costs do not directly affect the analyzed measures for potential Phase III facilities, they do have an indirect effect on all facilities within the NERC region, through potential increases in electricity prices and changes in fuel demand. As a result, measures such as changes in variable production cost/MWh and pre-tax income might be influenced by Phase II compliance costs, rather than Phase III regulation.

Table B5A-5: Facility-Level Impacts of Option 6 (by NERC Region; 2013)

Economic Measures	Base Case 1	Option 6	Difference	% Change
National Totals				
(1) Total Domestic Capacity (MW)	62,075	62,157	0	0.1%
(1a) Closures - Number of Facilities	3	4	1	33.3%
(1b) Closures - Capacity (MW)	1,047	964	(82)	(7.8)%
(2) Generation (GWh)	409,687	408,609	(1,078)	(0.3)%
(3) Revenues (Millions; $2003)	$14,165	$14,104	($60)	(0.4)%
(4) Costs (Millions; $2003)	$8,500	$8,468	($33)	(0.4)%
(4a) Fuel Cost	$4,798	$4,761	($37)	(0.8)%
(4b) Variable O&M	$1,129	$1,127	($2)	(0.2)%
(4c) Fixed O&M	$2,406	$2,412	$6	0.2%
(4d) Capital Cost	$168	$168	$0	0.2%
(5) Pre-Tax Income (Millions; $2003)	$5,664	$5,637	($28)	(0.5)%
(6) Variable Production Costs ($2003/MWh)	$14.47	$14.41	($0.06)	(0.4)%
East Central Area Reliability Coordination Agreement (ECAR)				
(1) Total Domestic Capacity (MW)	11,536	11,532	(4)	0.0%
(1a) Closures - Number of Facilities	0	0	0	0.0%
(1b) Closures - Capacity (MW)	0	4	4	n/a
(2) Generation (GWh)	83,922	83,922	0	0.0%
(3) Revenues (Millions; $2003)	$3,042	$3,039	($3)	(0.1)%
(4) Costs (Millions; $2003)	$1,601	$1,601	$1	0.0%
(4a) Fuel Cost	$907	$907	$0	0.0%
(4b) Variable O&M	$233	$233	$0	0.0%
(4c) Fixed O&M	$386	$387	$1	0.2%
(4d) Capital Cost	$74	$74	$0	0.0%
(5) Pre-Tax Income (Millions; $2003)	$1,441	$1,438	($4)	(0.3)%
(6) Variable Production Costs ($2003/MWh)	$13.59	$13.59	$0.00	0.0%
Electric Reliability Council of Texas (ERCOT)				
(1) Total Domestic Capacity (MW)	3,900	3,900	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)	16,418	16,482	64	0.4%
(3) Revenues (Millions; $2003)	$684	$657	($27)	(3.9)%
(4) Costs (Millions; $2003)	$445	$448	$3	0.7%
(4a) Fuel Cost	$246	$249	$3	1.0%
(4b) Variable O&M	$65	$65	$0	0.5%
(4c) Fixed O&M	$123	$123	$0	0.1%
(4d) Capital Cost	$11	$11	$0	3.1%
(5) Pre-Tax Income (Millions; $2003)	$239	$209	($30)	(12.7)%
(6) Variable Production Costs ($2003/MWh)	$18.94	$19.04	$0.10	0.5%
Florida Reliability Coordinating Council (FRCC)				

Table B5A-5: Facility-Level Impacts of Option 6 (by NERC Region; 2013)

Economic Measures	Base Case 1	Option 6	Difference	% Change
(1) Total Domestic Capacity (MW)	2,447	2,447	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)	13,227	12,714	(513)	(3.9)%
(3) Revenues (Millions; $2003)	$577	$555	($22)	(3.8)%
(4) Costs (Millions; $2003)	$317	$300	($17)	(5.5)%
(4a) Fuel Cost	$200	$183	($17)	(8.4)%
(4b) Variable O&M	$36	$36	($1)	(1.7)%
(4c) Fixed O&M	$81	$81	$0	0.0%
(4d) Capital Cost	$0	$0	$0	0.0%
(5) Pre-Tax Income (Millions; $2003)	$260	$255	($5)	(1.8)%
(6) Variable Production Costs ($2003/MWh)	$17.85	$17.21	($0.65)	(3.6)%
Mid-Atlantic Area Council (MAAC)				
(1) Total Domestic Capacity (MW)	6,420	6,420	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)	41,996	41,996	0	0.0%
(3) Revenues (Millions; $2003)	$1,515	$1,529	$14	0.9%
(4) Costs (Millions; $2003)	$813	$812	($1)	(0.1)%
(4a) Fuel Cost	$439	$438	($1)	(0.2)%
(4b) Variable O&M	$118	$118	$0	0.0%
(4c) Fixed O&M	$232	$232	$0	0.0%
(4d) Capital Cost	$24	$24	$0	0.0%
(5) Pre-Tax Income (Millions; $2003)	$702	$717	$15	2.1%
(6) Variable Production Costs ($2003/MWh)	$13.27	$13.25	($0.02)	(0.2)%
Mid-America Interconnected Network (MAIN)				
(1) Total Domestic Capacity (MW)	3,234	3,234	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)	22,247	22,247	0	0.0%
(3) Revenues (Millions; $2003)	$778	$777	($1)	(0.1)%
(4) Costs (Millions; $2003)	$443	$444	$1	0.2%
(4a) Fuel Cost	$267	$267	$0	0.0%
(4b) Variable O&M	$56	$56	$0	0.0%
(4c) Fixed O&M	$95	$96	$1	0.8%
(4d) Capital Cost	$25	$25	$0	0.0%
(5) Pre-Tax Income (Millions; $2003)	$335	$333	($2)	(0.6)%
(6) Variable Production Costs ($2003/MWh)	$14.54	$14.54	$0.00	0.0%
Mid-Continent Area Power Pool (MAPP)				
(1) Total Domestic Capacity (MW)	4,379	4,379	0	0.0%

Table B5A-5: Facility-Level Impacts of Option 6 (by NERC Region; 2013)

Economic Measures	Base Case 1	Option 6	Difference	% Change
(1a) Closures - Number of Facilities	0	0	0	0.0%
(1b) Closures - Capacity (MW)	0	0	0	0.0%
(2) Generation (GWh)	30,897	30,897	0	0.0%
(3) Revenues (Millions; $2003)	$955	$953	($2)	(0.2)%
(4) Costs (Millions; $2003)	$687	$687	$1	0.1%
(4a) Fuel Cost	$342	$341	$0	0.0%
(4b) Variable O&M	$83	$83	$0	0.1%
(4c) Fixed O&M	$263	$263	$1	0.3%
(4d) Capital Cost	$0	$0	$0	0.0%
(5) Pre-Tax Income (Millions; $2003)	$268	$265	($3)	(1.0)%
(6) Variable Production Costs ($2003/MWh)	$13.73	$13.73	$0.00	0.0%
Northeast Power Coordinating Council (NPCC)				
(1) Total Domestic Capacity (MW)	845	940	95	11.3%
(1a) Closures - Number of Facilities	0	1	1	n/a
(1b) Closures - Capacity (MW)	112	16	(95)	(85.6)%
(2) Generation (GWh)	791	647	(144)	(18.2)%
(3) Revenues (Millions; $2003)	$62	$54	($8)	(12.7)%
(4) Costs (Millions; $2003)	$40	$39	($1)	(3.5)%
(4a) Fuel Cost	$17	$13	($4)	(24.8)%
(4b) Variable O&M	$2	$2	$0	(18.1)%
(4c) Fixed O&M	$21	$24	$3	15.8%
(4d) Capital Cost	$0	$0	$0	0.0%
(5) Pre-Tax Income (Millions; $2003)	$21	$15	($6)	(30.3)%
(6) Variable Production Costs ($2003/MWh)	$24.53	$22.77	($1.75)	(7.2)%
Southeastern Electric Reliability Council (SERC)				
(1) Total Domestic Capacity (MW)	11,967	11,967	0	0.0%
(1a) Closures - Number of Facilities	1	1	0	0.0%
(1b) Closures - Capacity (MW)	207	207	0	0.0%
(2) Generation (GWh)	88,265	88,265	0	0.0%
(3) Revenues (Millions; $2003)	$3,104	$3,106	$2	0.1%
(4) Costs (Millions; $2003)	$1,859	$1,857	($2)	(0.1)%
(4a) Fuel Cost	$1,211	$1,209	($2)	(0.2)%
(4b) Variable O&M	$210	$210	$0	0.0%
(4c) Fixed O&M	$403	$403	$0	0.0%
(4d) Capital Cost	$34	$34	$0	0.2%
(5) Pre-Tax Income (Millions; $2003)	$1,245	$1,249	$4	0.3%
(6) Variable Production Costs ($2003/MWh)	$16.10	$16.08	($0.02)	(0.1)%
Southwest Power Pool (SPP)				
(1) Total Domestic Capacity (MW)	4,391	4,382	(9)	(0.2)%
(1a) Closures - Number of Facilities	0	0	0	0.0%

Table B5A-5: Facility-Level Impacts of Option 6 (by NERC Region; 2013)

Economic Measures	Base Case 1	Option 6	Difference	% Change
(1b) Closures - Capacity (MW)	0	9	9	n/a
(2) Generation (GWh)	14,995	14,510	(485)	(3.2)%
(3) Revenues (Millions; $2003)	$457	$441	($15)	(3.4)%
(4) Costs (Millions; $2003)	$381	$364	($17)	(4.4)%
(4a) Fuel Cost	$211	$196	($15)	(7.2)%
(4b) Variable O&M	$41	$40	($1)	(3.4)%
(4c) Fixed O&M	$129	$129	$0	(0.1)%
(4d) Capital Cost	$0	$0	$0	0.0%
(5) Pre-Tax Income (Millions; $2003)	$76	$77	$1	1.7%
(6) Variable Production Costs ($2003/MWh)	$16.81	$16.22	($0.59)	(3.5)%
Western Electricity Coordinating Council (WECC)				
(1) Total Domestic Capacity (MW)	12,956	12,956	0	0.0%
(1a) Closures - Number of Facilities	2	2	0	0.0%
(1b) Closures - Capacity (MW)	728	728	0	0.0%
(2) Generation (GWh)	96,928	96,928	0	0.0%
(3) Revenues (Millions; $2003)	$2,992	$2,995	$2	0.1%
(4) Costs (Millions; $2003)	$1,916	$1,916	$0	0.0%
(4a) Fuel Cost	$957	$957	$0	0.0%
(4b) Variable O&M	$284	$284	$0	0.0%
(4c) Fixed O&M	$674	$675	$0	0.0%
(4d) Capital Cost	$0	$0	$0	0.0%
(5) Pre-Tax Income (Millions; $2003)	$1,077	$1,079	$2	0.2%
(6) Variable Production Costs ($2003/MWh)	$12.81	$12.81	$0.00	0.0%

Source: IPM® analysis: Model runs for Section 316(b) Base Case 1 and Option 6.

Summary of Potential Phase III Facility Results at the National Level. The results presented in Table B5A-5 show that Option 6 would lead to one facility closure, and 82 MW (0.1% of Base Case 1 capacity) of avoided capacity closures. This outcome is the net result of two avoided partial facility closures (potential Phase III facilities with relatively low compliance costs that become more competitive relative to facilities with which they compete), one full policy closure, and two partial policy closures. It should be noted that all four facilities estimated to experience partial or full closures under Option 6 did not generate any electricity under Base Case 1. All four facilities are oil and gas-fueled facilities that served only reliability purposes. In addition, generation, revenues, and overall costs would all decrease under Option 6 but by less than 1%. Fixed O&M costs, which include the capital cost of compliance, are projected to increase by 0.2%. Pre-tax income for the group of potential Phase III facilities would decrease by 0.5%.

Summary of Potential Phase III Facility Results at the Regional Level. Results 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 Option 6 would result in the following changes:

- **NPCC** is the only region estimated to experience an increase in total capacity, gaining 95 MW (11.3% of Base Case 1 capacity) under Option 6. This outcome is the net result of two avoided partial facility closures, and one full policy closure. Potential Phase III facilities in NPCC are estimated to experience the largest relative reductions in generation and revenues of any NERC region (18.2% and 12.7%, respectively). The reduction in generation is attributable to two facilities that are projected to experience an increase in variable production costs. All potential Phase III facilities in NPCC are estimated to experience at least some reduction in revenues due to the estimated decrease in capacity prices (see Table B5A-4). Potential Phase III facilities in NPCC are also estimated to experience the largest relative reduction in pre-tax income (30.3%) of any region. Though the aforementioned changes are significant on percentage basis, they are relatively minor in absolute terms and consistent with the changes seen in the other regions. The only measure for which NPCC experiences the largest change on both a percentage basis and in absolute value is variable production costs.

- **ECAR** and **SPP** are the only regions projected to experience a net reduction in capacity due to Option 6. In ECAR 4 MW are estimated to retire, or less than 0.1% of ECAR's Base Case 1 capacity. In SPP 9 MW are estimated to retire, or 0.2% of SPP's Base Case 1 capacity. Neither region experiences changes in generation as a result of these partial closures. In addition, none of the 13 MW of retired capacity were dispatched under the Base Case 1.

- **ERCOT** is the only region projected to experience an increase in Phase III generation under Option 6, gaining 64 GWh, or 0.4%. However, potential Phase III facilities in ERCOT are also estimated to see the largest reductions in revenues ($27 million) and pre-tax incomes ($30 million). Revenues decrease even though generation in the region increases due to the large drop in capacity prices (see Table B5A-4). Specifically, the projected $93 million increase in energy revenues are offset by the projected $120 million decrease in capacity revenues.

- Potential Phase III facilities in **FRCC** are estimated to experience a 513 GWh reduction in generation (3.9%) due to Option 6. As a result, revenues decrease in by 3.8%, fuel costs decrease by 8.4%, and variable O&M costs decrease 1.7%.

- **MAAC**, **MAIN**, and **MAPP**, **SERC** and **WECC** are estimated to experience relatively small changes in pre-tax income (between -1.0% and 2.1%). The changes in all other measures are less than 1% in these regions.

b. Individual facilities potentially subject to Phase III regulation

In addition to the effects of Option 6 on potential Phase III facilities as a group, there may be shifts in economic performance among individual facilities potentially subject to Phase III 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 potential Phase III facilities that experience no changes, or an increase or a reduction within three ranges: 1% or less, 1 to 3%, and more than 3%.

Table B5A-6 presents the total number of potential Phase III facilities with different estimated degrees of change due to Option 6. This table excludes four facilities with estimated significant status changes in 2013: three facilities are baseline closures, and one facility is a full closure as a result of Option 6. These facilities are either not operating at all in either Base Case 1 or the post-compliance case, or they experience fundamental changes in the type of units they operate; therefore, the measures presented in Table B5A-6 would not be meaningful for these facilities. In addition, the change in variable production cost per MWh of generation could not be developed for six facilities with zero generation in either Base Case 1 or the post-compliance scenario. For these facilities, the change in variable production cost per MWh is indicated as "n/a."

Table B5A-6: Number of Potential Phase III Facilities with Operational Changes (2013)

Economic Measures	Reduction			Increase			No Change	N/A
	</= 1%	1-3%	> 3%	</= 1%	1-3%	> 3%		
(1) Change in Capacity Utilization	0	0	8	0	0	4	95	0
(2) Change in Generation	0	0	8	0	0	4	95	0
(3) Change in Revenues	42	2	15	9	4	4	31	0
(4) Change in Variable Production Costs/MWh	15	2	1	16	0	1	66	6
(5) Change in Fuel Costs/MWh	16	2	1	10	1	1	70	6
(6) Change in Pre-Tax Income	29	8	32	13	10	1	14	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: Model runs for Section 316(b) Base Case 1 and Option 6.

Table B5A-6 indicates that the majority of potential Phase III facilities would not experience changes in capacity utilization, generation, fuel costs per MWh, or variable production costs per MWh due to compliance with Option 6. Of those facilities with changes in post-compliance capacity utilization, generation, fuel costs per MWh, and variable production costs per MWh, most would experience decreases in these measures. Changes in revenues at most potential Phase III facilities would also not exceed 1.0%. The largest effect of Option 6 would be on facilities' pre-tax income: about 64% of facilities would experience a reduction in pre-tax income, with 30% experiencing a reduction of 3% or greater. These reductions are due to a combination of reduced revenues and increased compliance costs.

B5A-4 SUMMARY IPM® V.2.1.6 UPDATES

Table B5AA-1 below presents a summary of the series of updates that were incorporated in EPA modeling applications using the Integrated Planning Model (IPM®) in the Spring of 2003. Designated Version 2.1.6, the latest available data were used to update key model parameters in the EPA Base Case and associated policy cases in preparation for performing analyses in conjunction with Congressional consideration of the Administration's Clear Skies Initiative.

This table and its accompanying report, *Documentation Supplement for EPA Modeling Applications (V.2.1.6) Using the Integrated Planning Model* (U.S. EPA, 2003), is a supplement to the comprehensive documentation of EPA's applications of IPM® as reported in *Documentation of EPA Modeling Applications (V.2.1) Using the Integrated Planning Model* (U.S. EPA, 2002). The supplementary report consists of the summary table presented below and a series of attachments providing details of specific updates. To help readers track the parameters that were updated, Table B5AA-1 contains cross references to the earlier documentation report. Parameters not included in Table B5AA-1 remained unchanged. Both the supplemental and comprehensive documentation is available for viewing and downloading at www.epa.gov/airmarkets/epa-ipm.

Table B5AA-1 Summary Table of IPM® V.2.1.6 Updates

<table>
<tr><th>ID</th><th>Feature</th><th>Description</th><th>Doc. Report Section[1]</th></tr>
<tr><td colspan="4">Power System Operations Assumptions</td></tr>
<tr><td>1</td><td>Revised aggregation scheme

(“Documentation for v.2.1" refers to the report Documentation of EPA Modeling Applications (V.2.1) Using the Integrated Planning Model, EPA 430/R-02-004 (March 2002), which is available for viewing and downloading at www.epa.gov/airmarkets/epa-ipm.</td><td>The aggregation scheme was revised to enable modeling emission scenarios in geographical areas most likely to be of future interest. Table A-1 in Attachment A updates the crosswalk between actual and model plants that was previously presented as Table 4.7 in the documentation for v.2.1. Table A-2 and the accompanying map provides details on the geographical aggregation scheme used in the v.2.1.6.</td><td>3.1
4.2.6
Appendix A4.1</td></tr>
<tr><td>2</td><td>Electricity Demand Growth: @ 1.55% indexed on AEO 2003 electricity sales projections.

(AEO 2003 refers to Annual Energy Outlook 2003 with Projections to 2025, DOE/EIA-0383(2003), released by the U.S. Department of Energy’s Energy Information Administration on January 9, 2003.)</td><td>1. As was done in EPA’s previous applications of IPM®, calculations were performed to account for efficiency improvements not factored into AEO 2003's projections of electricity sales. This resulted in a 2000-2020 adjusted electricity growth rate of 1.55% per year.

Attachment B provides details.</td><td>3.2.1
3.2.2
Appendix A3.1</td></tr>
<tr><td>3</td><td>State Multi-Pollutant Regulations</td><td>Attachment C lists the state multipollutant programs incorporated in v.2.1.6.</td><td>3.9</td></tr>
<tr><td>4</td><td>New Source Review (NSR) Settlements</td><td>Attachment D shows the settlements under New Source Review provisions of the Clean Air Act that were included in v. 2.1.6.</td><td>3.9.3</td></tr>
<tr><td>5</td><td>State Renewable Energy Programs</td><td>V. 2.1.6 incorporates the capacity shown in Table 76 in the AEO 2003 assumptions document. Entitled “Planned 2002+ U.S. Central Station Generating Capacity Using Renewable Resources,” the table captures the effects of state renewable energy programs in its projection of both existing and forecasted renewable capacity. Table 76 appears on pp. 131-133 of the document “Assumptions for the Annual Energy Outlook 2003," which can be found on the Web at www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2003).pdf.</td><td>3.9.4
(Not covered)</td></tr>
<tr><td>6</td><td>State Renewable Portfolio Standards (RPS)</td><td>V. 2.1.6 does not endogenously model RPS beyond the capacity already implicit in Table 76 “Planned 2002+ U.S. Central Station Generating Capacity Using Renewable Resources.” (See previous item for information on locating this table.)</td><td>3.9.4
(Not covered)</td></tr>
<tr><td>7</td><td>Emission and removal rate assumptions for potential units.</td><td>The emission and removal rates are the same as in AEO 2003, i.e.,<table><tr><th></th><th>NOx Rates</th><th>SO2 Rates</th></tr><tr><td>Conventional Pulverized Coal (CPC)</td><td>0.11 lb/mmBtu</td><td>95% Removal</td></tr><tr><td>Integrated Gasification Combined Cycle (IGCC)</td><td>0.02 lb/mmBtu</td><td>99% Removal</td></tr><tr><td>Combined Cycle (CC)</td><td>0.02 lb/mmBtu</td><td>—</td></tr><tr><td>Combustion Turbine (CT)</td><td>0.08 lb/mmBtu</td><td>—</td></tr></table>These differ from the removal rates in v. 2.1 (also called EPA Base Case 2000). See Attachment E for a detailed breakdown of the differences.</td><td>3.9.5</td></tr>
</table>

Table B5AA-1 Summary Table of IPM® V.2.1.6 Updates

ID	Feature	Description	Doc. Report Section[1]
Generating Resources			
8	National Electric Energy Data System (NEEDS) Changes The following changes were made to NEEDS, the database that serves as the source of all currently operating and planned/committed units represented in v.2.1.6.		4.1 4.2
8a	AES Deepwater Unit	The AES Deepwater generating unit in Texas (ID #10670_G_GEN1) was identified as combusting fossil waste in NEEDS 2000 (used for the EPA Base Case 2000, v2.1) but as combusting oil in EPA's Emissions and Generation Resource Integrated Database (EGRID). Further investigation revealed that this unit burned petroleum coke and some oil. To give a more accurate representation of its mercury emissions, in v. 2.1.6 the unit was designated as combusting petroleum coke and assigned a corresponding mercury emission rate of 23.18 lb/TBtu (dry).	
8b	Mercury Emission Rates for Existing Geothermal Units	Based on recent information obtained by EPA, mercury emission rates were updated to 2.97 lbs/TBtu for existing geothermal units in California and 3.65 lbs/TBtu for existing geothermal units in the IPM® model region NWPE. In addition, 29 MW of existing geothermal capacity was identified in the AZNM model region and 8 MW in the PNW model region and assigned an emission rate of 3.70 lbs/TBtu, the same emission rate as assigned to new potential geothermal units in v.2.1.6. (See item #10 below.)	
8c	Hawthorn Unit 5	This 550 MW coal unit was added to NEEDS, v. 2.1.6.	
8d	Updated information on unit closures	Units that were shown as retired or out of service in 2000 EIA 860a were removed from the NEEDS database as part of the v.2.1.6 update. Based on supplemental information, Ashtabula units 8, 10 and 11, Arapahoe units 1 and 2, Arkwright units 1 - 4, 5A, 5B,and Mitchell units 1 and 2 were also removed from the NEEDS population, either because they were retired or out of service.	4.2
8e	Life Extension Costs	A life extension cost of $5/kW-yr is added to every fossil plant that reaches an age of 30 years. This assumption is based on AEO 2003.	4.2.4 and 4.3.4
8f	SO_2, NO_x, and Particulate Controls	The inventory of SO_2, NO_x, and particulate controls in v.2.1.6 was derived from U.S. EPA's Emission Tracking System, 2002, Quarter 2, supplemented by corroborated information obtained from utilities, control technology vendors, state and regional regulatory agencies, and trade publications and announcements. Attachment F shows the inventory of emission controls on existing generating units that are included in v.2.1.6.	4.2.5
8g	Updated planned/committed capacity	Existing and planned/committed units in NEEDS 2.1.6 were derived from the following data sources: <u>Period</u> — <u>Source</u> 1998 and earlier — NEEDS 2000 All planned/committed capacity after 1998 in NEEDS 2000 was removed and replaced with the following data. 1999-2000 — EIA 860, as released in year 2000. EIA 860 shows operating units for these years. 2001 — RDI. (Updated through the July 2002 release of the RDI database.) 2002-2005 — AEO 2003 or RDI. AEO 2003 was used for renewable (biomass, geothermal, landfill gas, hydro, pumped storage, solar, and wind) and non-conventional generating units (fuel cells) due to the Energy Information Administration's (EIA) extensive	4.3

Table B5AA-1 Summary Table of IPM® V.2.1.6 Updates

ID	Feature	Description	Doc. Report Section[1]
		research in this area for AEO 2003. The RDI database (up through the July 2002 release) was used for conventional generating units (coal steam, combined cycle turbines, combustion turbines, fossil and non-fossil waste) since it was more current than AEO 2003. Attachment G lists the planned/committed units included in NEEDS 2.1.6 and gives a detailed summary of the data sources used.	
9	Cost and Performance of Potential (New) Capacity from Conventional Generating Units	The cost and performance assumptions for new (potential) conventional pulverized coal, integrated gasification combined cycle, combined cycle, advanced combined cycle, and combustion turbine units were updated based on AEO 2003. See Attachment H for details.	4.4.2
10	Mercury emissions for new (potential) geothermal units	Based on recent information obtained by EPA, the mercury emission rate for new (potential) geothermal plants was updated to 3.70 lbs/TBtu in v.2.1.6, compared to 4.08 lbs/TBtu in v.2.1. (See item 8b above for a description of related updates of the mercury emission rates for existing geothermal plants.)	4.4.3 5.3.1
Existing Nuclear Units			
11a	Cost and performance	1. To provide maximum granularity in forecasting the behavior of nuclear units, 102 out of the 103 existing nuclear units in v.2.1.6 are represented by separate model plants. (Note: All nuclear generating units, except Browns Ferry units 1 and 2 are represented by a separate model plant. In the v.2.1.6 base case, Browns Ferry Unit 1, which is projected to be brought out of mothballs, is represented by the same model plant as Browns Ferry Unit 2. See item 11c below for further details.) In v.2.1, the 103 existing nuclear units were represented by 47 model plants. 2. AEO 2003 cost and performance assumptions were implemented. These include (a) Variable operations and maintenance (VOM), fixed operations and maintenance (FOM), and fuel cost assumptions as in AEO 2003. Attachment I details the cost assumptions included in v. 2.1.6. (b) AEO 2003 assumption of cost incurred from age 30, i.e., an addition of $50/Kw/yr to annual FOM costs starting at age 30. (c) Availability assumptions are expressed in terms of capacity factors, which are based on AEO 2003. As in AEO 2003, v. 2.1.6 assumes two vintages of existing nuclear units, based on whether a unit's start date occurs before or after 1982. For the older vintage, the capacity factor increases 0.5 percentage point per year through age 25, stays flat from 25-40, and then declines by 0.5% point after 40. The capacity factor of a newer vintage unit increases by 0.7 percentage point per year through age 30, is flat from 30-40, and declines by 0.5% point after age 40. The maximum capacity factor is assumed to be 90%. Any plant starting with a capacity factor above 90% just remains at its current level, at least until it is old enough to start declining. 3. In v.2.1.6 existing nuclear units are constrained to retain the same retirement pattern as in AEO 2003.	4.5 Appendix 4.4
11b	Upratings	All the nuclear capacity uprating assumptions that are in AEO 2003 were incorporated in NEEDS 2.1.6. A listing of all upratings appears in Attachment J.	4.5 Appendix 4.4
11c	Browns Ferry Unit 1	V. 2.1.6 uses the same assumptions about this TVA unit being brought out of mothballs as in AEO 2003, i.e., 1. The unit has a zero capacity factor (availability) until 2007. Starting	4.5 Appendix 4.4

Table B5AA-1 Summary Table of IPM® V.2.1.6 Updates

ID	Feature	Description	Doc. Report Section[1]
		in 2007, it can operate up to a 75% capacity factor. 2. Like other existing nuclear units its capacity factor grows by 0.7% per year until it reaches a maximum of 90%. 3. Its costs were assumed to be the same as those for Browns Ferry Unit 2.	
Emission Control Technologies			
12	Selective Non-Catalytic Reduction (SNCR) Control of NOx Emissions	In v. 2.1.6 SNCR is available as an emission control retrofit option for all coal plants ≥25 MW and < 200 MW rather than to all plants ≥ 25, as in v.2.1. In both v.2.1 and v.2.1.6 SNCR is available to all oil/gas steam units ≥ 25 MW.	5.2.2
13	Gas Reburn Option for NOx Control at coal fired plants	To reduce model size, this option, which was provided in v 2.1, was not offered in v2.1.6.	5.2.2
14	Mercury Emission Modification Factors (EMFs)	Mercury emission modification factors are multipliers that represent the extent of mercury removal achieved by various configurations of NO_X, SO_2 and particulate emission controls at coal fired generating units. Based on additional information received on the performance of these controls, mercury EMFs were updated. Attachment K shows the mercury EMFs used in v. 2.1.6.	5.3.2 5.3.3 Appendix A5.4
15	Mercury Control Using Activated Carbon Injection (ACI)	Instead of modeling ACI with an 80% mercury removal rate, as was done in v. 2.1, v.2.1.6 has the capability to provide two concurrent ACI options of 60% and 90% mercury removal. The two options could be used for special mercury analyses. However, v. 2.1.6 will use an ACI mercury removal rate of 90% for typical analyses. Due to constraints on model size and run time, the 60% removal option is intended to be applied only on selected sensitivity analysis runs.	5.3.3 Appendix A5.3
16	Mercury Control Costs Using ACI	Based on information received from ACI vendors as an outgrowth of the Mercury MACT FACA process, the cost and injection rates for ACI were revised. ("Mercury MACT FACA process" refers to the advisory committee set up under the Federal Advisory Committee Act (FACA) to enable EPA to obtain input on proposed regulations governing maximum achievable control technology (MACT) for mercury removal from electric generating units.) (See Attachments L1 and L2 for a complete development of the ACI cost equations used in v. 2.1.6.)	Appendix A5.3.2
Financial Assumptions			
17	Revised financial assumptions for Integrated Gasification Combined Cycle (IGCCs) plants.	With the following exceptions, the financial assumptions in v.2.1.6 are the same as in EPA Base Case 2000 (v.2.1): IGCCs and Repowerings-to-IGCCs are assigned the discount rate (DR) and capital charge rate (CCR) associated with high (rather than medium) risk investments, i.e., DR = 6.74%, not 6.14%. CCR = 13.4%, not 12.9%	7
Fuel Assumptions			
18	Coal Supply Curves	To provide greater consistency between the v.2.1.6 and the AEO 2003 coal supply curves, the regional coal supply curves in v.2.1.6 were adjusted to reflect the percentage change in labor productivity assumed in AEO 2003. The coal transportation cost escalation rates in v.2.1.6 were also made consistent with those assumed in AEO 2003. See Attachment M for a presentation of the AEO 2003 labor productivity and transportation escalator assumptions.	8.1
19	Natural Gas Supply Curves	Updated gas supply curves were generated using ICF Consulting Inc.'s North American Natural Gas Analysis System (NANGAS) model. Key activities included: 1. Gas supply curves were developed for the 2005-2025, modeling	8.2 Appendix 8.1

Table B5AA-1 Summary Table of IPM® V.2.1.6 Updates

ID	Feature	Description	Doc. Report Section[1]
		horizon, rather than the 2005-2020 period used earlier. 2. Earlier optimistic technology assumptions, developed for the Department of Energy's National Energy Technology Laboratory's (NETL), were reviewed and revised resulting in a somewhat less optimistic technology perspective. 3. The Gulf of Mexico East drilling moratorium was incorporated in NANGAS. 4. EIA success rates for Gulf of Mexico offshore were adopted. 5. Pipeline links were checked to ensure correct gas flow, e.g., making sure the Rockies-Southwest link shows gas flows from the Rockies to the Southwest rather than the reverse. 6. Seasonal transportation adders were updated. 7. Four initial NANGAS runs were performed to cover the range of anticipated electric demand growth rates. A separate NANGAS run was performed at electric demand annual growth rates of 1.1%, 1.55% (EPA's CCAP adjusted growth rate), 1.88% (approximating the AEO 2003 Reference Case electricity sales growth rate), and 2.2%. 8. Outputs from the four runs were used to produce an initial set of natural gas supply curves for incorporation in IPM®. 9. A series of iterations was performed between NANGAS and IPM® until convergence was achieved in the IPM® and NANGAS electric sector results. The gas supply curves generated by this process were incorporated in v.2.1.6. Attachments N contains the natural gas supply curves used in v. 2.1.6 for each model run year and the seasonal transportation adders.	
20	Oil prices consistent with AEO 2003	1. V. 2.1.6 fuel prices for distillate oil and high and low sulfur residual oil were based on the AEO 2003. The prices used in v.2.1.6 are shown in Attachment O together with the AEO 2003 source data from which the prices were derived. 2. The sulfur content for these fuels were defined to be consistent with AEO 2003, i.e., Fuel — Sulfur Content Distillate — 0.3 Residual: Low Sulfur — 1.08 Residual: High Sulfur — 2.69	8.3
Miscellaneous Other Features			
21	SO_2 allowance bank	An SO2 allowance bank of 6.414 million tons (going into 2005) was assumed.	
22	Feasibility constraint on the maximum amount of SO_2 scrubbers that can be built in 2005 under the v.2.1.6 Clear Skies run	The maximum amount of SO_2 scrubbers that could be built in 2005 was limited to 5066 MW in the Clear Skies run. This is consistent with recent EPA assessments of the short-term feasibility of scrubber installations.	

[1] This column indicates the most closely related sections in *Documentation of EPA Modeling Applications (V. 2.1) Using the Integrated Planning Model* (U.S. EPA, 2002).

Source: U.S. EPA, 2003.

B5A-5 UNCERTAINTIES AND LIMITATIONS

There are uncertainties associated with EPA's electric power market and economic impacts analyses conducted in developing the proposed rule:

Demand for electricity: The IPM® assumes that electricity demand at the national level would not change between the base case and the policy case (generation within the regions is allowed to vary). Under the base case specifications, electricity demand is based on the AEO 2003 forecast.[14] The IPM® model, as specified for this analysis, does not capture changes in demand that may result from electricity price increases associated with Option 6. 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 obtained in developing the proposed rule. As described in Section B5A-3 above, the price increases associated with the Option 6 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® assumes that imports from Canada and Mexico would not change between the base case and the policy case. Holding international imports fixed would provide a conservative estimate of production costs and electricity prices under Option 6, because imports are not subject to Phase III regulation 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 2013 only four of the ten NERC regions import electricity (ECAR, MAPP, NPCC, and WECC) and the level of imports compared to domestic generation in each of these regions is very small (from less than 0.01% in ECAR, to 2.75% in NPCC).

- ***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 Option 6.

- ***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. Downtimes under Option 6 are estimated to be either 2 or 9 weeks, depending on the technology. Generator downtime is estimated to occur during the year when a facility complies with Option 6. 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 2010 to 2012 are all mapped into 2010. Therefore, a facility with a downtime in 2011 was modeled as if 1/3rd of its downtime occurred in each year between 2010 and 2012. 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

[14] EPA also considered conducting an analysis under a third base case adjusted to account for demand reductions resulting from implementation of the Climate Change Action Plan (CCAP) as was done for the Phase II analysis.

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 C1: Summary of Cost Categories and Key Analysis Elements for New Offshore Oil and Gas Extraction Facilities

INTRODUCTION

This chapter presents an overview of the cost categories and certain elements of the analytic framework that are common to the economic analyses of the two major industry segments covered by the proposed standards for new Offshore Oil and Gas Extraction facilities: mobile offshore drilling units (MODUs) and oil and gas production platforms or structures.

CHAPTER CONTENTS

C1-1 COST CATEGORIES

In its analyses of the costs and economic impacts of the proposed rule on new oil and gas extraction facilities, EPA considered three categories of costs:

- costs of installing and operating compliance technology,
- administrative costs incurred by complying facilities, and
- administrative costs incurred by permitting authorities.

In contrast to the analysis conducted for the Manufacturing and Electric Generating industry segments (see also Chapter B1), EPA assumed that no downtime would be associated with installing or maintaining CWIS technologies for new offshore oil and gas extraction facilities, for two reasons. First, new facilities do not have to retrofit equipment; the equipment is built to specification and installed before the facility begins operations. Second, even the maintenance of CWISs should not result in downtime in the oil and gas industry, since MODUs are hauled out on a regular basis for other types of maintenance activities, and production platforms are shut in one to two times per year for other maintenance, making incremental downtime due to CWIS maintenance unlikely (see the *Technical Development Document for the Proposed Section 316(b) Phase III Rule* (hereafter referred to as the "*Phase III Technical Development Document*"; U.S. EPA, 2004b).

Subsection C1-1.1 provides an overview of the three cost categories included in the analysis for new offshore oil and gas extraction facilities, addressing those aspects of each category that are relevant to the oil and gas industry. Table C1-1 summarizes the type of new offshore oil and gas extraction facility assumed to be subject to Phase III regulation and the compliance technologies considered for each facility type. Subsection C1-1.2 presents information on administrative costs incurred by new oil and gas facilities. Additional detail on the costs of installing and operating compliance technology is provided in the *Phase III Technical Development Document*.

C1-1.1 Cost of Installing and Operating Compliance Technology

Oil and gas drilling and production facilities would need to implement technologies to reduce impingement mortality and/or entrainment. The choice of technology varies depending on CWIS diameter and flow rate or diameter, or type of CWIS (e.g., sea chest or simple pipe). Note that for new MODUs, which EPA assumes will use sea chests, only impingement requirements would apply. EPA determined that entrainment controls on sea chests are not technically practicable (U.S. EPA, 2004b).

Table C1-1: Technologies for Implementing 316(b) Requirements for New Offshore Oil and Gas Extraction Facilities

Category	CWIS Type	Technology Description
Platform	Simple Pipe or Caisson	Stainless steel wedge wire screen - no air sparge cleaning
Platform	Simple Pipe or Caisson	Stainless steel wedge wire screen - with air sparge cleaning
Platform	Simple Pipe or Caisson	CuNi wedge wire screen - no air sparge cleaning
Platform	Simple Pipe or Caisson	CuNi wedge wire screen - with air sparge cleaning
Platform	Simple Pipe or Caisson	Stainless steel and CuNi velocity caps
Jackup	Simple Pipe or Caisson	Cylindrical wedge wire screen over tower inlet
Jackup	Simple Pipe or Caisson	Horizontal Flow Modifier
Jackup[a]	Sea Chest	Flat panel wedge wire screen over sea chest opening
Jackup[a]	Sea Chest	Horizontal Flow Diverter for Side Sea Chests
Jackup	Submersible Pumps	Cylindrical wedge wire screen over suction pipe inlet
Submersibles, Semi-Submersibles and Drill Ships[a]	Sea Chests	Flat panel wedge wire screen over sea chest
Submersibles, Semi-submersibles and Drill Ships[a]	Sea Chests	Horizontal flow diverter over side sea chest
Drill Barges	Simple Pipes	Cylindrical wedge wire screen over simple pipes
Drill Barges	Simple Pipes	Velocity Cap on the CWIS

[a] All semi-submersibles and drill ships and most jackups in EPA's technical database use sea chests. EPA determined that entrainment controls on sea chests are not technically practicable. New MODUs, which are represented by typical existing MODUs, are assumed to use sea chests (see U.S. EPA, 2004b).

Source: U.S. EPA, 2004b.

EPA developed technology cost estimates for the proposed rule based on the impingement mortality and entrainment reduction technologies (as appropriate) projected for each new oil and gas facility. Technology costs include capital costs and operating and maintenance (O&M) costs. The technology costs developed for the proposed rule analysis are engineering cost estimates, expressed in July 2002 dollars. These costs were converted to mid-year 2003 values (see Section C1-2.2 below for a discussion of adjusting monetary values to a common time period of analysis).

More detailed information on the compliance technologies considered by EPA, on technology costs, and on EPA's characterization of baseline technologies already in-place at new offshore oil and gas extraction facilities, is available in the *Phase III Technical Development Document*. In addition, *Chapter C3: Economic Impact Analysis for the Offshore Oil and Gas Extraction Industry* provides more detail on the engineering costs assumed for each of the different types of oil and gas facilities analyzed in this report.

C1-1.2 Administrative Costs for Complying Facilities

Compliance with the standards of the proposed rule requires new offshore oil and gas extraction facilities to carry out certain administrative functions. For Phase III existing facilities, these administrative functions, which help them determine their compliance requirements and provide the documentation needed for issuance of their new National Pollution Discharge Elimination System (NPDES) permits, fall on each facility individually. For oil and gas facilities, however, General Permits apply.

There are three General Permits (GPs) that would apply to new offshore oil and gas extraction facilities subject to Phase III regulation. The Region 6 General Permit applies to the relatively active Western Gulf of Mexico (GOM) region; the Region 4 General Permit applies to the currently relatively inactive Eastern GOM region, and the Region 10 General Permit (Cook Inlet permit) applies to Cook Inlet, Alaska. The GPs are expected to be rewritten to accommodate the requirements of section 316(b) following promulgation of the final rule and as each GP comes up for renewal at the end of its 5-year cycle.

The current Region 6 permit was effective as of 2002, expired in 2003, and is planned for renewal in 2004. Study of produced water will reopen in 2007. The likely beginning rounds of the post-promulgation schedule of this permit is thus 2007 and 2012. The Region 4 permit expired in 2003. It is likely to be renewed in 2004. The probable post-promulgation GP renewal schedule is considered to be 2009 and 2014. The planned renewal date of the general permit for Cook Inlet is January 2005 but the permit expires in 2004. The likely post-promulgation renewal schedule is thus 2009 and 2014.

The rule is scheduled to be promulgated in 2006, with the effective date assumed to be the beginning of 2007. Three years of environmental studies are assumed to be required prior to permitting under the section 316(b) rule. Thus, the first possible compliance date after the 2007 effective date would be 2010. However, the general permits may not be able to incorporate section 316(b) requirements during the 2007-2009 repermitting cycles. Therefore, EPA assumed that the oil and gas industries would be required to comply starting in 2012 (or 2014 in the case of Region 4 and 10 permits).

Because the rule becomes effective in 2007, however, EPA is assuming, for both simplicity and to be conservative, that starting in 2007, new offshore oil and gas extraction facilities would have installed and would be operating relevant CWIS controls, since they would be relatively inexpensive to install during construction. The pre-permitting studies are assumed to start in 2007 (for both Region 6 and Region 4), but other permitting tasks would not begin until the year prior to when the GPs renewals are finalized (2012 or 2014), or the year prior to when the facility is assumed to come on line or be launched, whichever is later. Monitoring would only begin in the year the renewals are finalized or the year in which the facility comes on line or is launched, again, whichever is later. The timing assumptions for Region 6 and Region 4 permits may overstate costs, since costs are moved several years earlier in the analysis time frame than they would be if EPA assumed only those facilities constructed in 2012 or later incur compliance costs. The costs of compliance in this industry, however, are relatively small overall, so the numerical significance of any overestimation would be small. More specific details of the timing assumptions of costs incurred are provided in a memorandum to the Rulemaking record (ERG, 2004).

Because new offshore oil and gas extraction facilities would be subject to Phase III regulation under these GPs, EPA assumes that certain administrative functions can be shared among new facilities. All MODUs and platforms expected to be built in the first five years before the revised Region 6 General Permit is issued (2012) are expected to share the initial costs of certain biological characterization studies that would be required by section 316(b) under the Region 6 GP. They are also assumed to share the cost of monitoring studies, which must be performed at a minimum for the first two years of the permit and then at least once per year for each repermitting cycle. Only MODUs are assumed to share the costs of permitting studies under the Region 4 GP. Permitting costs for platforms are assumed to be those incurred under the Region 6 permit. Should platforms be constructed in Region 4 locations, permitting costs would be similar to Region 6 permitting costs. Since it is not known which MODUs may operate in the Eastern GOM, all MODUs constructed in 2007 and beyond are assumed to incur permitting costs under a Region 4 GP. This roughly doubles the permitting costs assigned to MODUs. The assumption may overstate total costs, since not all MODUs may operate in the Eastern Gulf, and there may be significant costs savings once a Region 6 permit application is completed, since much of the information required for both permits would most likely be identical.

Only one Alaska project is anticipated, at most, over the period of analysis (see *Chapter C2: Profile of the Offshore Oil and Gas Extraction Industry*), so this project is expected to incur the entire cost of facility permitting. This project is assumed to go on line in the year the Region 10 permit is finalized (2014). For this project, EPA assumes that the 3-year studies are performed in the three years prior to start-up (2011-2013).

The administrative functions associated with incorporating the 316(b) requirements into the applicable General Permits are either one-time requirements (compilation of information for the initial post-promulgation General Permits) or recurring requirements (compilation of information for subsequent General Permit renewals; and monitoring, record keeping, and reporting). More detailed information on the derivation of permitting activities and costs can be seen in U.S. EPA (2004a).

a. Initial post-promulgation General Permit application

EPA assumes that the proposed rule would encourage firms to pool their resources. Therefore, those firms that are planning to construct new platforms or MODUs to operate in the GOM within the first 5 years before the applicable General Permit is reissued with 316(b) requirements in place are assumed to share certain pre-permitting costs. EPA expects that these firms will hire a consultant to perform the more general information gathering tasks required of industry before facilities can be permitted under a GP and also to perform the two years of monitoring studies required in the first two years of the permit (monitoring costs are assumed shared by the number facilities permitted in the first or second year of the first permit cycle). Other activities are specific to each facility and it is assumed each facility will incur the cost of these activities individually. Some of the permitting activities, however, may not be incremental to existing requirements. Minerals Management Service (MMS) will be finalizing a rule (possibly mid-August, 2004) that will require some of the same information (U.S. EPA, 2004a). The MMS rule is, however, not applicable to Cook Inlet. All information submitted would be consistent with Phase I, Track 1 requirements. 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. This is a facility-specific activity.

- ***Permit application activities:*** identifying source water physical data, velocity information, and cooling water intake structure data, including description of CWIS operations, flow distribution and water balance diagram, and drawings and maps to support CWIS descriptions, and maintaining copies of these records. These activities are assumed facility-specific, but several of the activities duplicate activities required by MMS. There are no incremental costs associated with duplicate activities.

- ***Source waterbody flow and CWIS velocity flow information****:* Information used to demonstrate that the facility's CWIS meets the proportional flow requirements. The CWIS velocity flow information and demonstration is assumed to be facility-specific, but none of these activities is incremental to MMS requirements. The waterbody flow calculation activities are only those associated with compiling site-specific information. Other waterbody characterization activities that can be shared are included in the biologic characterization study activities.

- ***Design and construction technology plan:*** delineation of the hydrologic zone of influence for the CWIS, description of technologies to be implemented; the basis for technology selection; expected performance of the technology; and design calculations, drawings and estimates to support the technology description and performance. These activities are assumed facility-specific. Development of the narrative description of technologies is considered an MMS requirement, so no costs are assumed incurred for this activity.

- ***Source water baseline biological characterization data:*** characterization of the biological community in the region and operation of CWISs; list of species in region; identification and evaluation of primary period of reproduction, larval recruitment, and period of peak meroplankton abundance for relevant taxa; and description of the likely impact of CWISs on the biological community due to impingement and entrainment. This is considered a regional study to be conducted over a 3-year period by a contractor; costs are assumed to be shared among affected facilities, since the entire monitoring program is assumed to apply region-wide.

Table C1-2 below lists the estimated costs per facility of each of the initial post-promulgation General Permit activities described above (permit costs for MODUs in the Eastern GOM are lower in some cases, since MODUs are assume to use sea chests and are not required to meet entrainment requirements, eliminating any costs associated with entrainment studies).

Table C1-2: Cost of Initial Post-Promulgation NPDES General Permit Application Activities (Per Facility, 2003$)

Activity	Region 6	Region 4	Region 10
Start-up activities[a]	$2,171	$2,171	$2,171
Permit application activities[b]	$925	$925	$925
Source waterbody flow information[a]	$1,416	$1,416	$1,416
CWIS velocity flow information[f]	$0	$0	$0
Design and construction technology plan[b]	$1,282	$1,141	$1,282
Biological characterization study[c,e]	$63,942	$39,871	$296,564
Total Initial Post-Promulgation NPDES General Permit Application Cost[d]	**$69,737**	**$45,524**	**$302,358**

[a] The costs for these activities are incurred in 2007 for facilities built in 2007 to 2011 in both Eastern and Western Gulf. For Alaska, they occur in 2011.
[b] The costs for these activities are incurred in 2011 for facilities built in 2007 to 2012 for both Eastern and Western Gulf. For Alaska, they occur in 2013.
[c] The costs for these activities are incurred during 2007-2009 in the Eastern and Western Gulf and are shared costs. For Alaska, these costs are incurred during 2011-2013.
[d] Individual numbers may not add to total due to independent rounding.
[e] Shared study costs.
[f] Measured as incremental to MMS requirements.

Source: U.S. EPA, 2004a. See also ERG, 2004.

b. Subsequent NPDES General Permit Renewals

Subsequent General Permit renewals would require collecting and submitting the same type of information required for the initial permit renewal application. EPA expects that both the facility and the contractor can use some of the information from the initial studies. 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. The shared recurring permit costs are assumed to be shared by all new offshore oil and gas extraction facilities built in the first 5-year cycle plus all new facilities built in the next 5-year cycle, etc., so as time goes on, shared costs are shared by more and more facilities (except Alaska, where only one project is assumed during the time frame of the analysis). As facilities go off line or are retired (after 30 years), fewer projects share in these studies.
Table C1-3 lists the estimated costs of each of the NPDES General Permit renewal activities subsequent to the first round. Since these numbers change slightly as facilities come on or off line, the costs shown are for the first repermitting cycle following the initial GP renewal.

Table C1-3: Cost of Subsequent NPDES General Permit Application Activities (Per Facility, 2003$)

Activity	Region 6	Region 4	Region 10
Start-up activities[a]	$692	$692	$692
Permit application activities[a]	$190	$190	$190
Source waterbody flow information[a]	$401	$401	$401
CWIS velocity flow information[a]	$0	$0	$0
Design and construction technology plan[a]	$802	$694	$802
Biologic characterization study[a]	$12,005	$7,455	$194,932
Total Recurring NPDES Permit Application Cost[d]	**$14,090**	**$9,432**	**$197,017**

[a] The costs for these activities are incurred during the year of the General Permit renewal. Shared costs shown are for the first permit renewal period after the initial permit (e.g., 2017); these costs change as the number of permitted facilities change. For simplicity, all costs for repermitting are assumed to be incurred in one year, rather than spread over several years as was assumed for the initial round of permitting.

Source: U.S. EPA, 2004a. See also ERG, 2004.

c. Annual monitoring, record keeping, and reporting

Annual monitoring, record keeping, and reporting activities and costs include:

- Biologic monitoring for impingement
- Biologic monitoring for entrainment
- Velocity monitoring
- Preparing and maintaining a yearly status report

Table C1-4 on the following page outlines the associated costs of these activities.

Table C1-4: Cost of Monitoring Activities (Per Facility, 2003$)

Activity	Region 6	Region 4	Region 10
Biologic monitoring for impingement	$4,350	$1,963	$0
Biologic monitoring for entrainment	$2,710	$0	$46,078
Velocity monitoring[a]	$1,004	$453	$6,192
Preparing and maintaining yearly status report	$1,775	$801	$10,945
Total Monitoring Cost	**$9,839**	**$3,217**	**$63,215**

[a] The costs for these activities are incurred during the first two years of the initial General Permit renewal (i.e., 2012 or 2014) and are shared. These costs are incurred for one year in each subsequent permit renewal cycle. Shared costs shown are for the first permit cycle only (2012 or 2014); these costs change as the number of permitted facilities change over time.

Source: U.S. EPA, 2004a. See also ERG 2004.

d. Administrative Costs for Permitting Authorities

In addition, permitting authorities have to review the information provided by new offshore oil and gas extraction facilities and have to issue new general permits that reflect the requirements of the proposed rule. These activities impose costs on the responsible governmental units. For more details on the specific costs and timing assumptions for federal administration of new offshore oil and gas extraction facilities, see *Chapter D2: UMRA Analysis*. These costs and assumptions are summarized briefly below.

The requirements of section 316(b) are implemented through the National Pollutant Discharge Elimination System (NPDES) permit program. In the case of the oil and gas industry, NPDES permitting is consolidated under several General Permits, which are administered at the EPA regional level. Unlike the Phase III existing facilities discussed in *Chapter B1: Summary of Cost Categories and Key Analysis Elements for Existing Facilities*, no states are involved in these permitting activities. Thus, three Regions (Region 6, Region 4, and Region 10) are expected to be the only entities responsible for permitting. Because states are not involved in permitting, there are no costs associated with Federal oversight as there are for state-administered NPDES permits. The three Regions would incur three types of costs associated with implementing the requirements of the proposed rule on a per-facility basis, i.e., for each facility permitted under a GP: (1) start-up activities (considered not incremental to existing activities; $0 cost) , (2) activities associated with the initial General Permit containing the new section 316(b) requirements ($12,309 in each region) and subsequent permit renewals ($5,018 in each region), and (3) annual activities ($1,428 in each region).[1]

The start up activities apply only once to each Region, but the remaining activities are incurred on a per-facility basis.

For a detailed discussion of administrative costs for permitting authorities, see *Chapter D2: UMRA Analysis*, section D2-1.2.

C1-2 KEY ELEMENTS OF THE ECONOMIC ANALYSIS FOR NEW OFFSHORE OIL AND GAS EXTRACTION FACILITIES

The economic analysis of regulation of new offshore oil and gas extraction facilities addresses the cost to, and impact on, the affected industry segments and society generally. Although these analyses differ in important respects for the individual industry segments – particularly in terms of the analytic models and methods for assessing the economic/financial impact of the proposed rule on complying parties within the segments – several elements of the analysis have features common to all new offshore oil and gas extraction facilities. This section reviews the following key common elements:

- Compliance Schedule
- Adjusting Monetary Values to a Common Time Period of Analysis
- Discounting and Annualization: Costs to Society or Social Costs
- Discounting and Annualization: Costs to Complying Facilities

C1-2.1 Compliance Schedule

For its analysis of the cost and impacts of the proposed rule, EPA developed a profile of the expected compliance year (year in which the new MODU or platform is launched or comes on line) for each of the types of facilities considered in the economic analysis. Unlike the analysis for the Phase III existing facilities, the compliance year is not necessarily the same year as the year in which the facility must comply with the General Permit, since EPA is assuming that CWIS controls are installed and are operating in new MODUs and platforms starting in 2007,

[1] The costs associated with implementing the requirements for new offshore oil and gas extraction facilities are documented in EPA's Information Collection Request (U.S. EPA, 2004a).

even though the first General Permit is assumed to be reissued with 316(b) requirements in 2012. Developing an explicit profile of compliance years for new offshore oil and gas extraction facilities is important because the schedule of compliance years determines the timing of outlays by facilities and society in complying with the regulation, both for the initial outlays and for the ongoing profile of outlays in maintaining compliance with the regulation. This information is important in properly assessing the present value of the regulation's costs to society.

For the analysis, EPA initially assumed that firms planning to build facilities in the first permit cycle (Region 6 General Permit) (2012-2016) would contract to perform the studies necessary for these facilities to be permitted starting in 2007. The Region 4 permit is assumed not to incorporate 316(b) requirements until 2014, but studies are started in 2007 as well. Starting in 2014, any new MODUs are assumed to incur the costs of the Region 4 permit as well as the Region 6 permit. No platforms/structures are assumed to incur costs of the Region 4 permit (they will incur the costs of one permit only, assumed to be issued under the Region 6 General Permit). The next group of facilities to be launched or come on line in the next permit cycle (2017 or 2019) would need to be involved only in repermitting activities for the shared studies, and thus, for the shared costs, would share repermitting costs with each other as well as with operations begun in the first 5-year cycle. These new operations would, however, incur initial permitting costs among those activities that are facility specific. The years in which facilities are expected to be completed are specifically spelled out, given the number of facilities expected to be completed in each year (see *Chapter C2: Profile of the Offshore Oil and Gas Extraction Industry*). More information on specific timing assumptions can be seen in ERG (2004) and the 316(b) Oil and Gas Compliance Cost Model (DCN 7-4018).

C1-2.2 Adjusting Monetary Values to a Common Time Period of Analysis

The various economic information used in the cost and impact analyses were initially provided or estimated in dollars of different years. For example, facility financial data obtained in the 316(b) survey for the oil and gas industry are for the years 2000, 2001, and 2002, while the technology costs of regulatory compliance were estimated in dollars of the year 2002. To support a consistent analysis using these data that were initially developed in dollars of different years, EPA needed to bring the dollar values to a common analysis year. For this analysis, EPA adjusted all dollar values to constant dollars of the year 2003 (average or mid-year, depending on availability) using an appropriate inflation adjustment index. For adjusting compliance costs, EPA used the Construction Cost Index (CCI) published by the Engineering News-Record.

a. CCI

EPA used the CCI to adjust compliance cost estimates from July 2002 to mid-year 2003. EPA judges the CCI as generally reflective of the cost of installing and operating process and treatment equipment such as would be required for compliance with Phase III regulation. Table C1-5, following page, shows CCI values for July, 2002 and June, 2003.

Table C1-5: Construction Cost Index

Year	Value	% Change
July 2002	6605	
June 2003	6694	1.3%

Source: ENR, 2004.

b. GDP Deflator

EPA used the GDP Deflator to adjust 316(b) survey financial data from 2000, 2001, and 2002 to 2003. The GDP Deflator is a quarterly series that measures the implicit change in prices, over time, of the bundle of goods and services comprising gross domestic product. Table C1-6 shows GDP Deflator values from 2000 to 2003. From 2000 to 2003, the total change in the deflator series was 5.7% (105.7/100.0).

Table C1-6: GDP Deflator Series

Year	Value	% Change
2000	100.0	
2001	102.4	2.4%
2002	103.9	1.5%
2003	105.7	1.7%

Source: U.S. BEA, 2004.

C1-2.3 Discounting and Annualization – Costs to Society or Social Costs

Discounting refers to the economic conversion of future costs (and benefits) to their present values, accounting for the fact that society tends to value future costs or benefits less than comparable near-term costs or benefits. Discounting is important when the values of costs or benefits occur over a multiple year period and may vary from year to year. Discounting is also important when the time profiles of costs and benefits are not the same – which is the case for the regulatory analysis of new oil and facilities. Discounting enables the accumulation of the cost and benefit values from multiple years at a specified point in time, accounting for the difference in how society values those costs and benefits depending on the year in which the values are estimated to occur.

For its analysis of the costs to society, or the social costs, of the proposed rule for new offshore oil and gas extraction facilities, EPA first developed a profile of the costs expected to be incurred as a result of the regulation over the period of analysis. EPA defined the analysis period as follows. The analysis period begins in 2007 (5 years before the first of the General Permits is reissued with 316(b) requirements) and includes facilities constructed over the next 20 years – i.e., to 2026 – *plus* a period of 30 years in which each newly constructed facility is assumed to continue compliance. Thus, for the social cost analysis for Phase III new offshore oil and gas extraction facilities, the analysis period extends to 2055 (see the 316(b) Oil and Gas Compliance Cost Model, DCN 7-4018). In developing the time profile of costs, EPA assigned costs according to the following schedule:

a. Direct Costs of Regulatory Compliance

- ***Capital Costs of Compliance Technology:*** This cost is first incurred in the year that the facility begins operation. However, the equipment for complying with the regulation is expected to have a useful life of 10 years, or a period shorter than the 30 years of compliance. Accordingly, following the first installation, facilities are assumed to reinstall, and re-incur the cost of, the compliance equipment at year 11 and year 21 of the facility-specific compliance period.

- ***Compliance Technology Operation and Maintenance:*** This cost is assumed to occur in each year of a facility's 30-year compliance year period.

b. Administrative Costs Incurred by Complying Facilities

- ***Biological Characterization Study:*** This is a three-year study required for all facilities, which is assumed to be shared by the affected facilities. The cost of this study is incurred over the years immediately following the effective date of the proposed rule or the years preceding the first post-promulgation GP (2007-2009 for Eastern and Western Gulf, and 2011-2013 for Alaska).

- ***Initial Permitting Cost***. In addition to incurring a share of the cost of characterization studies, complying facilities would also incur an initial permitting cost, which is assigned to the year preceding the first year of a facility's 30-year compliance period, or in 2007 for facilities launched or coming on line in 2007 through 2011.

- ***Repermitting Costs:*** As explained above, General Permits are renewed each five years during the period of compliance. Repermitting costs, both shared and facility-specific, are assumed to recur at years 5, 10, 15, 20, and 25 of the General Permit cycles. For new offshore oil and gas extraction facilities, EPA assumes that 30 years is the reasonable maximum lifetime of these facilities; thus, no repermitting cost is incurred in the 30^{th} year of facility operation.

- ***Annual Monitoring, Record Keeping, and Reporting Activities:*** These costs are assumed to occur in the first two years of the initial permit and in each year of the permit renewal year. These costs begin in 2012 or 2014, depending on permit.

c. Administrative Costs Incurred by Permitting Authorities

- ***One-time Start-up Costs:*** These costs are assumed to be nonincremental to existing costs of permitting in the three regions.

- ***Permit Processing Costs:*** These costs are assigned to the years in which facilities apply for initial permits or renewal permits during the compliance period.

- ***Annual Permit Administration Activities:*** The cost of these activities is assumed to occur in parallel with the annual permit-related activities by complying facilities and thus occurs in each year of a facility's compliance period.

EPA assigned costs by facility and governmental unit according to this framework and then summed these costs on a year-by-year basis over the total time period of analysis. For the social cost analysis, these costs were tallied on a pre-tax basis, which differs from the treatment of costs for the facility impact analysis as described below. These profiles of costs by year were then discounted to the assumed date the final rule would take effect, beginning of year 2007, at two values of the social discount rate, 3% and 7%. These discount rate values reflect guidance from the Office of Management and Budget regulatory analysis guidance document, Circular A-4 (OMB, 2003).[2]

For more detailed information see ERG (2004) and the 316 (b) Oil and Gas Compliance Cost Model (DCN 7-4018).

EPA used the following formula to calculate the present value of the time stream of costs as of the beginning of 2007:[3]

$$Present\ Value = \frac{Cost_t}{(1 + r)^{t-2007}}$$

where:

$Cost_t$	=	Costs in year t
r	=	Social discount rate (3% and 7%)
t	=	Year in which cost is incurred (2007 to 2055)

After calculating the present value of these cost streams, EPA calculated their constant annual equivalent value (annualized value) using the annualization formula presented below, again using the two values of the social discount rate, 3% and 7%. Although the analysis period extends from 2007 through 2055, a period of 49 years,

[2] See *Chapter E1: Summary of Social Costs*, for further discussion of the framework for analyzing the social costs of the 316(b) Phase III regulation.

[3] Calculation of the present value assumes that the cost is incurred at the beginning of the year.

inclusive, EPA annualized costs over 30 years, since 30 years is the assumed period of compliance. This same annualization concept and period of annualization were also followed in the analysis of benefits, although for benefits the time horizon of analysis for calculating the present value is longer than for costs. Using a 30-year annualization period for both social costs and benefits allows comparison of constant annual equivalent values of costs and benefits that have been calculated on a mathematically consistent basis. The annualization formula is as follows:

$$Annualized\ Cost\ =\ PV\ of\ Cost \times \frac{r \times (1 + r)^{(n-1)}}{(1 + r)^{n} - 1}$$

where:

r = Social discount rate (3% and 7%)
n = Annualization period, 30 years for the social cost analysis

C1-2.4 Discounting and Annualization – Costs to Complying Facilities

In general, EPA followed similar concepts and procedures in the discounting and annualization required for the analysis of costs to, and impacts on, complying facilities as those followed for the analysis of social costs. However, the analysis of costs to complying facilities differs from that for costs to society in several important ways, which are described below.

- ***Consideration of taxes.*** For understanding the impact of the regulation on complying facilities, the costs incurred by complying facilities are adjusted for taxes, as relevant, and calculated on an after-tax basis. The tax treatment of compliance outlays and income effects (e.g., from installation) shifts part of these costs to the tax-paying public and reduces the actual cost to private, tax-paying businesses. For this reason, the after-tax costs of compliance are a more meaningful measure than the pre-tax costs of the financial burden on complying facilities. In analyzing and reporting the impact of compliance costs on private facilities, annualized costs are therefore calculated on an after-tax basis. Since most companies that operate MODUs or platforms are headquartered in states without corporate income taxes, EPA assumes a state tax rate of 0%. On the Federal level, EPA assumes that the highest marginal corporate tax rate applies. This rate is 35% (IRS, 2002), so post-tax costs will be 65% of the pre-tax costs. EPA does this because all platform and MODU owners that are likely to operate in Alaska or the Gulf of Mexico are large corporations by SBA standards and/or all have earnings in most years that place them in the highest corporate tax bracket.

- ***Calculation of present value and annualization of costs at the year of compliance.*** In the social cost analysis, costs were summed on a present value basis at the beginning of 2007, the assumed date the final regulation would take effect. For the analysis of costs to complying facilities, costs were calculated on a present value basis and annualized at the first year of compliance for each facility (assumed to be the year the facility is brought on line or launched). The calculation of annualized costs at the first year of compliance provides more accurate and meaningful insight for assessing financial impact in relation to the baseline financial performance and conditions of the complying facility than would be achieved if, for example, costs were further discounted – and reduced numerically – by bringing them to the year the rule would take effect. The aggregates of annualized cost *over facilities* for purposes of reporting total cost to complying facilities and total financial burden are likewise the sum of costs at the initial year of compliance for each facility, even though those years differ across facilities. These costs are annualized and used to report the aggregate costs to industry. The costs used to determine impacts are derived somewhat differently and the method used to incorporate them into the impact analysis varies by type of facility (MODU or platform) as explained in *Chapter C3: Economic Impact Analysis for the Offshore Oil and Gas Extraction Industry*.

- ***Use of discount rates in present value and annualization calculations.*** The discounting and annualization calculations for the complying facility cost calculations use the same formulas as used for the social cost calculations. However, the discount rate used in the facility cost calculations generally has a different interpretation than the rate used for the social cost calculation (even though the numerical value of the rate may be the same). Instead of being a social discount rate, the discount rate used for the present value and annualization calculations for complying facility costs represents a cost of capital to the individual complying facility, which may reasonably differ from the concept of the social discount rate. The social discount rate may be derived on several bases, including as an opportunity cost of capital *to society* or as a societal inter-temporal preference or indifference rate – i.e., the required rate of change over time in a value of consumption or outlay at which society would be indifferent to the time period in which the consumption or outlay occurs. The social discount rates based on these *society-level* concepts may reasonably differ from the cost of capital used for assessing costs and financial impacts to the complying firm.

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Chapter C2: Profile of the Offshore Oil and Gas Extraction Industry

CHAPTER CONTENTS

INTRODUCTION

EPA's proposed 316(b) cooling water intake rulemaking would affect new construction among offshore components of the oil and gas industry. The proposal would affect new offshore oil and gas extraction facilities only, because EPA has decided not to regulate existing oil and gas facilities. This profile compiles and analyzes economic and financial data for several sectors of the offshore oil and gas extraction industry that may be affected by certain of the Phase I 316(b) requirements for new facilities that are being proposed for new offshore oil and gas extraction facilities under Phase III. The profile characterizes the firms and facilities that currently exist to provide information on the characteristics of facilities that might be constructed in the future and the firms that are most likely to construct such facilities. The review of existing facilities that would be subject to Phase III regulation, *if they were newly constructed*, is also informative in showing the relatively small number of facilities that EPA has excluded from coverage by not including existing oil and gas facilities in this proposal.

Two key industry sectors are primarily associated with offshore oil and gas drilling and production, both of which might intake ambient cooling water from the surrounding oceans or navigable waterways for a wide variety of cooling needs. EPA also investigated the liquid natural gas (LNG) re-gasification industry, but determined that all but one new LNG facility currently planned would meet the 316(b) requirement that 25% or more of total intake flow be used for cooling water purposes (U.S. EPA, 2004). EPA proposes to apply Best Professional Judgment (BPJ) to this industry. This industry, therefore, is not discussed further.

The two major offshore oil and gas extraction industry users of CWIS are:

- mobile offshore drilling units (MODUs)
- offshore oil and gas production platforms

The following sections provide a profile for MODUs and production platforms (Sections C2-1 and C2-2). Within each profile, a brief overview of the industry is provided, including a look at existing facilities and their associated firms, and the financial conditions of those firms (where firm financial data are publicly available). The existing facilities are then discussed in more detail to provide information for the financial modeling of new facilities. Also discussed are factors affecting the future of each of these two groups of CWIS users. Finally, EPA projects the numbers of new MODUs or platforms that might be constructed with CWIS flow rates greater than 2 MGD, greater than 20 MGD, and greater than 50 MGD during the construction portion of the time frame of this economic analysis (construction spans the years 2007 to 2026). As discussed in Section C1, EPA decided to apply a similar regulatory structure to new offshore oil and gas extraction facilities as had been applied to new facilities for the 316(b) Phase I regulation: impingement and entrainment (I&E) controls are required on all new offshore oil and gas extraction facilities that have a total CWIS intake flow rate of 2 MGD or more (except for MODUs using sea chests, which are subject to impingement controls only).

Section C2-3 concludes this chapter with a summary of the estimated total number of new facilities in the offshore oil and gas extraction industry with at least 2 MGD intake rates by MGD flow rate category.

C2-1 MOBILE OFFSHORE DRILLING UNITS (MODUS)

C2-1.1 Overview

Offshore drilling operations often use MODUs, which are vessels or other sea-going rigs that are used to transport drilling equipment to the offshore site and from which drilling operations can be undertaken. The MODUs of interest are active primarily in the State offshore waters of the Gulf of Mexico (GOM). MODUs operating close to shore in State waters tend to be small barges and submersibles that do not use cooling water at the rates of concern (significantly less than 2 MGD) (U.S. EPA, 2004).

MODUs provide nearly all of the exploration and delineation drilling in the offshore development of oil and gas resources. MODUs also provide developmental drilling services. In exploratory drilling, drilling is undertaken to determine whether oil and gas resources are available near existing fields or in areas where no resources have been previously found (wildcats). Once an exploratory well has identified the presence of potentially recoverable oil and gas resources, delineation drilling is undertaken. Delineation entails the drilling of additional wells to determine the extent and nature of the new field. These two types of drilling often occur at a distance from existing platforms and thus are usually conducted from a mobile rig.

Drilling of development wells can be done from either a platform or a MODU. The same types of mobile rigs used to drill exploratory and delineation wells can also be used to drill developmental wells. Once a field has been delineated and a decision is made to develop the field, a platform is typically constructed and developmental drilling is initiated to construct wells for producing the field. A discussion of platform-based drilling is presented below in Section C2-2.

MODUs encompass a variety of vessel or rig types. The two basic groups of MODUs are bottom-supported units and floating units. **Bottom-supported units** include submersibles and jackups. **Floating units** include inland barge rigs, drill ships, ship-shaped barges, and semi-submersibles.

Bottom-supported drilling units are typically used when drilling occurs in shallow waters. Types of bottom-supported units include:

- Submersibles–barge-mounted drilling rigs that are towed to the drill site and sunk to the bottom. These rigs may be either posted barge or bottle type. A posted barge rig consists of a barge hull that rests on the bottom, with steel posts that rise from the top of the hull and a deck built on top of the posts well above the water line. These are used in water depths no more than 30 to 35 feet. A bottle type submersible consists of several steel cylinders or bottles. When the bottles are flooded, the rig submerges and sinks to the bottom, and when water is removed, they rise to the surface. These rigs can be used in water depths up to 100 feet.

- Jackup rigs–barge-mounted rigs with extendable legs that are retracted during transport. At the drill site, the legs are extended to the seafloor. As the legs continue to extend, the barge hull is lifted above the water. Jackup rigs, which can be used in waters up to 300 feet deep, can be categorized by their leg type: columnar leg and open-truss leg.

Floating drilling units are typically used when drilling occurs in deep waters and at locations far from shore. Types of floating units include:

- Semi-submersible–a type of floating drill unit that can withstand rough seas with minimal rolling and pitching tendencies, thus they are used for drilling projects in ultra-deep water Gulf regions. They are hull-mounted and float on the surface of the water when empty. At the drilling site, the hulls are flooded and sunk to a certain depth below the surface of the water. When the hulls are fully submerged, the unit is stable and not susceptible to wave motion due to its low center of gravity. The unit is moored with anchors to the seafloor. The two types of semi-submersible rigs are bottle-type (similar in concept to the bottle-type submersible) and column-stabilized.

- Drill ships and ship-shaped barges–vessels that float on the surface of the water equipped with drilling rigs. These vessels maintain position above the drill site by anchors on the seafloor or the use of propellers mounted fore, aft, and on both sides of the vessel (dynamic positioning). Drill ships are the other major drilling rig used in ultra-deep Gulf waters. In these locations, drill ships typically operate using dynamic positioning. Drill ships and ship-shaped barges are susceptible to wave motion since they float on the surface of the water, and thus are not suitable for use in heavy seas.

Of the five basic types of MODUS (submersibles, jackups, semi-submersibles, drill ships, and drill barges), the drill ships, semi-submersibles, and jackups are the three types that typically intake over 2 MGD of cooling water, with drill ships having the highest intake rates. Among drill ships with known intake rates above 2 MGD, all intake more than 50 MGD. Jackups and semi-submersibles do not generally appear to intake more than 20 MGD, but many intake more than 2 MGD. Submersibles and drill barges generally have cooling water intake below the 2 MGD cutoff. Drilling operations use cooling water for purposes such as cooling engines, compressors, winches, and pumps (U.S. EPA 2004).

C2-1.2 Existing MODUs and Their Associated Firms

Table C2-1 presents a listing of the existing MODUs' owners and the number of rigs they are currently operating in the GOM (as of 2002). These include MODUs that may have CWIS intake rates that do not exceed 2 MGD. Most MODUs are held by just a few firms. GlobalSantaFe, Transocean, Rowan Companies, Noble Corp. Parker Drilling, Pride International, ENSCO International, and Diamond Offshore operate 326 MODUs, 85% of the total.[1] The firms that own MODUs generally work as contractors to the oil and gas exploration and production industry. The provision of drilling and related services to U.S. and/or foreign offshore regions is the major focus of their business.

[1] This count includes 53 MODUs currently operating outside of U.S. waters, which EPA is treating as not regulated by the rulemaking.

Table C2-1: Number of Existing MODUs and Parent Firms

Company	Number of Rigs
Atwood Oceanics	3
Blake Drilling & Workover	19
Blue Dolphin	1
BSI Drilling	3
Caspian Drilling Company	2
Cyprus Company	1
Diamond Offshore	29
Energy Equipment Resources	1
ENSCO International Inc	30
Global Santa Fe	56
Nabors Industries	15
Newfield Exploration Company	1
Noble Corp.	22
NR Marine	1
Ocean Rig Asa	2
Parker Drilling	37
Pride International	29
Rowan Companies Inc	24
Tetra Technologies	7
Transocean Inc.	99
Workships BV	2
Total Number of Rigs	384

Source: ERG, 2004d; Table C2-2.

Table C2-2 presents the operating companies associated with the parent companies listed in Table C2-1. The total number of potentially affected parent firms is 21. These affiliations were determined primarily on the basis of Security and Exchange Commission (SEC) data. SEC maintains an online database (the Edgar Database), on which all filings of publicly held firms are available. The 10K annual reports and 8K reports are used the most to collect this information. The 10K annual reports to SEC generally list significant subsidiaries and are the source of income statement and balance sheet information for characterizing financial conditions at a firm. Subsidiary lists are used to confirm ownership relationships. The 8-K forms, in which significant changes to the firm must be announced, are often the source of information on mergers and acquisitions.

Table C2-2: Owners of MODUs Currently Operating in GOM and Parent Company

Listed Owner	Parent Company
Atwood Deep Seas	Atwood Oceanics
Atwood Oceanics	Atwood Oceanics
Blake Workover & Drilling	Blake Workover & Drilling
BSI Drilling	BSI Drilling
Caspian Drilling Company	Caspian Drilling Company
Chiles Offshore	ENSCO International, Inc.
Diamond Offshore	Diamond Offshore
Drillmar	Blue Dolphin
Energy Equipment Resources	Energy Equipment Resources
ENSCO	ENSCO International, Inc.
ENSCO Offshore Company	ENSCO International ,Inc.
Enserch Exploration	Newfield Exploration
Falcon Drilling Company	Transocean, Inc.
Global Marine Deepwater	GlobalSantaFe
Global Marine Drilling Co.	GlobalSantaFe
Global Marine North Sea Inc	GlobalSantaFe
GlobalSantaFe	GlobalSantaFe
Global Santa Fe/Glomar	GlobalSantaFe
Glomar	GlobalSantaFe
Hercules Offshore	Parker Drilling
Mallard Bay Drilling	Parker Drilling
Marine Drilling Companies	Pride International
Nabors	Nabors Industries
Nabors Offshore	Nabors Industries
Noble	Noble Corp.
Noble Drilling Corp	Noble Corp.
Noble Drilling US	Noble Corp.
Noble International	Noble Corp.
Noble Mexico	Noble Corp.
NR Marine	NR Marine
Ocean Rig Asa	Ocean Rig Asa
Parker Drilling	Parker Drilling

Table C2-2: Owners of MODUs Currently Operating in GOM and Parent Company

Listed Owner	Parent Company
Pride International	Pride International
Pride Offshore	Pride International
R&B Falcon	Transocean, Inc.
Rowan	Rowan Companies
Rowan Companies, Inc	Rowan Companies
Rowan/Rowan Companies, Inc.	Rowan Companies
Rowan/Rowan Drill, Inc.	Rowan Companies
Rowan/Rowan International Inc.	Rowan Companies
Seatanker's Management	Cyprus Company
Tetra Applied Technology	Tetra Technologies
Transocean	Transocean, Inc
Transocean Sedco Forex	Transocean, Inc
Transocean/Deepwater Drilling LLC	Transocean, Inc
Workships BV	Workships BV

Source: ERG, 2004d; SEC, 2003.

The identification of corporate parent is critical to determining which firms should be defined as small under SBA standards. SBA defines the size of the firm to be that of the firm at the highest level of organization. Generally, EPA characterized a firm at the higher level of organization if it was majority owned by the larger entity. This approach is consistent with SBA's definition of affiliation. Small firms that are affiliated (e.g., 51% owned) by firms defined as large by SBA's standards (13CFR Part 121) are not considered small for the purposes of regulatory flexibility analysis (see Section D1 for more details). Affiliated firms can also be firms owned by the same owners or that have the same corporate officers as another firm.

Another key piece of information needed for classifying firms as small or large is what industry the firm belongs to. SBA defines small businesses differently for different types of industry and currently uses NAICS to classify industries. SEC still requires companies to report their SIC code, not the NAICS code. Crosswalks between NAICS and SIC, however, are available from Bureau of the Census (2004).

Once the parent firms were identified as above and the proper NAICS identified based on the reported SIC code in the 10K reports and the NAICS crosswalk information, the revenue and employment (or other criteria, as appropriate) for these parent firms were determined and compared to the SBA definition of small based on their NAICS classification. Table C2-3 shows the SBA definitions for the industries identified.

It is assumed that all domestic firms that could not be identified as large are small businesses. Also, for the purposes of this analysis, MODU operators owned by foreign firms are assumed to be large, even when data on employment could not be found, because SBA defines a small business as one "with a place of business in the United States, and which operates primarily in the United States or which makes a significant contribution to the economy" (13 CFR Part 121). Only large businesses in this industry would meet the latter criteria, and few, if any, foreign firms operate primarily in the United States.

Table C2-3 presents the number of MODU parent companies by NAICS and SIC code, where that information is available. For the most part, those identified as small may not actually be small but are apparently privately owned and no information was available to support defining them as large. Eight firms are foreign-owned and presumed large. Industrial classification data are unavailable for foreign firms. Only two firms are positively identified as small, out of the 21 total firms operating existing MODUs, but four companies believed to be domestic could not be identified as small or large, so are presumed to be small. These firms (along with foreign-owned firms) are not counted in the number of firms shown in Table C2-3, because their NAICS classifications are also unknown.

Table C2-3: NAICS Classification of MODU Parent Companies

SIC code	NAICS code	NAICS Description	SBA Definition of Small	Total Number of Firms[a]	
				Small	Large
1311	211111	Crude Petroleum and Natural Gas Extraction	500 employees	2	0
1381	213111	Drilling Oil and Gas Wells	500 employees	0	6
1389	213112	Support Activities for Oil and Gas Operations	$7.5 million in revenues	0	1
2819	211112	Natural Gas Liquid Extraction	500 employees	0	1

[a] Does not include seven foreign firms and four unknown firms for which NAICS or SIC codes could not be located in publicly available data.

Source: SEC, 2003; 13 CFR Part 121.

Table C2-4 presents the financial conditions at the parent firms listed in Table C2-2. A number of parent companies are privately held or are foreign and do not have financial information available on the SEC database, so information is not presented for these firms. The financial data shown are from 2002, the base year for the new offshore oil and gas extraction facility analysis. The total assets of the MODU parent companies range from $8 million to $12.7 billion. The revenues range from $3 million to $2.7 billion. The three financial ratios calculated in the table are the return on assets, return on equity, and the profit margin. Each of these ratios calculates the net income as a ratio over the total assets, stockholder's equity, and total revenues respectively, and are commonly used measures of financial health in the oil and gas industry. The return on assets percentages range from -29.5% to 6.8%, and the profit margin ranges from -139% to 21%.

Table C2-4: Financial Condition of MODU Parent Companies (2002)

Firms	Size	Type	No. of Employees	Assets ($000)	Equity ($000)	Revenues ($000)	Net Income ($000)	Return on Assets	Return on Equity	Profit Margin
Atwood Oceanics	Large	Other	800	$445,238	$276,133	$149,157	$28,285	6.35%	10.24%	18.96%
Blake Drilling & Workover	Small*	Other								
Blue Dolphin	Small	Other	11	$7,775	$5,765	$2,910				
BSI Drilling	Small*	Other								
Caspian Drilling Company	Large**	Foreign								
Diamond Offshore	Large	Independent	3,766	$3,258,765	$1,335	$752,561	$62,520	1.92%	4683.15%	8.31%
Energy Equipment Resources	Small*	Other								
ENSCO International, Inc	Large	Other	4,300	$3,061,500	$1,967,000	$698,100	$59,300	1.94%	3.01%	8.49%
GlobalSantaFe	Large	Foreign	8,800	$5,808,200	$4,234,200	$2,017,700	$277,900	4.78%	6.56%	13.77%
Nabors Industries	Large	Foreign	15,261							
Newfield Exploration Company	Small	Independent	488	$2,315,753	$1,009,231	$661,750	$73,847	3.19%	7.32%	11.16%
Noble Corp.	Large	Independent	3,747	$3,065,714	$1,989,210	$986,356	$209,503	6.83%	10.53%	21.24%
NR Marine	Small*	Other								
Ocean Rig Asa	Large**	Foreign								
Parker Drilling	Large	Other	2,898	$953,325	$300,626	$389,946	($114,054)	-11.96%	-37.94%	-29.25%
Pride International	Large	Other	10,100	$4,324,995	$1,699,705	$1,269,774	($8,947)	-0.21%	-0.53%	-0.70%
Rowan Companies Inc	Large	Other	5,237	$2,054,504	$1,131,777	$617,258	$86,278	4.20%	7.62%	13.98%
Cyprus Company	Large**	Foreign								
Tetra Technologies	Large	Other	1,391	$308,817	$184,152	$242,606	$8,899	2.88%	4.83%	3.67%
Transocean Inc.	Large	Foreign	13,200	$12,665,000	$7,141,000	$2,674,000	($3,732,000)	-29.47%	-52.26%	-139.57%
Workships BV	Large**	Foreign								

* Presumed small due to lack of data.
**Presumed large–foreign-owned.

Source: *Table C2-2; SEC, 2003, U.S. EPA 2000.*

C2-1.3 Existing MODUs with Intake Rates Meeting Proposed Rule Criteria

a. Overview of Existing MODUs as Models for New MODUs

To provide information on whether new MODUs might be subject to Phase III regulation, EPA investigated information obtained from a survey of MODUs undertaken for the Phase III rulemaking decision. Not all of the MODUs owned by the firms listed above meet the applicability standard (at least 2 MGD design intake flow) and other criteria of the proposed rule. EPA used a multi-step process to estimate the total number of existing MODUs that would be regulated under the proposed rule if they were newly constructed (i.e., CWISs with total design flow of at least 2 MGD or more or less than 25% of intake volume used for cooling water purposes).[2] The sampling frame used 384 MODUs as shown in Table C2-1). Among these 384 MODUs in this universe, EPA sampled 30 MODUs in the survey. The survey weights for all MODUs is thus 384 divided by 30, or 12.8.

The following is the status of the economic survey respondents:

- 23 respondents returned surveys
- 8 respondents were determined to have CWISs that meet proposed rule criteria.
- 15 respondents were determined to have CWISs that do not meet proposed rule criteria or were not operating in U.S. waters
- 4 surveys were not returned from among a group of MODUs whose CWIS intake rates were known (based on voluntary data submitted during the 316(b) Phase I rulemaking)
- 3 surveys were not returned among a group of MODUs whose CWIS intake rates were unknown.

Based on the ratio of respondents whose intake rates meet proposed rule criteria to total respondents (8/23), EPA assumes that among the three MODUs with unknown intake rates, one will have intake rates meeting the proposed rule's criteria and two will have intake rates not meeting these criteria. Thus, the total number of MODUs in the economic survey sample whose intake rates are assumed to meet proposed rule criteria is estimated to be 13. Multiplying this number by the survey weight of 12.8 yields an estimate of a total of 166 MODUs with intake rates meeting proposed rule criteria. Another six MODUs, originally thought to have intake rates of less than 2 MGD were determined to have intake rates greater than 2 MGD, and these are added to the estimate of MODUs with CWISs meeting proposed rule criteria, for a total of 172 MODUs meeting the proposed rule's criteria – roughly half of the existing MODUs operating in U.S. waters (331 MODUs or about 52 %). EPA therefore assumes that approximately half of new MODUs built might meet proposed rule criteria. Of the 172 MODUs meeting proposed rule criteria, EPA estimates that all new semi-submersibles and jackups will have CWIS flow rates below 20 MGD, based on all surveyed semi-submersibles and jackups having rates below 20 MGD. EPA also estimates that all new drill ships will have rates above 50 MGD, based on all surveyed drill ships having intake rates of this size. For more information on the estimate of existing MODUs that might meet proposed rule criteria, see ERG, 2004a.

b. Current Drilling Activity and Trends

In 2002, 62 wells were drilled offshore in the Gulf of Mexico on Federal offshore leases. Offshore drilling rigs are extremely capital intensive. Therefore, once a company has invested in a rig, it is in their best interest to keep the rig in operation. Currently, the utilization of all rigs worldwide stands at 72%, which is down significantly from 85% in 1998 (Drilling Contractor, 2003a). Trends seem to indicate increased utilization in certain regions however, such as in the Gulf of Mexico. The jackup market, in particular, has shown pricing improvement in the GOM. The Bureau of Land Management's Minerals Management Service (MMS) projects that oil production in the Gulf of Mexico should be between 1.5 and 2.0 million barrels per day (bpd) by the end of 2005 and gas production should be between 11 and 17 billion cubic feet per day (bcfd) by the same time period. Deepwater

[2] For simplicity, the text refers to operations that meet either of these criteria as not meeting proposed rule criteria, even though the proposed rule does not apply to existing facilities..

exploration and deep exploration in the shallow waters of the GOM are expected to continue to grow. Deepwater exploration in the Gulf of Mexico is projected to be a significant source of new oil and gas supplies in future years (Drilling Contractor, Nov/Dec 2001).

c. Estimates of New MODUs To Be Constructed

The progress report published by *Offshore* magazine shows that the majority of offshore production investment in 2003 is in the refurbishment of old rigs, however some new rigs are being built. In 2003, the majority of new offshore construction comprised jackup rigs. Surveys indicate that 14 jackups were completed in 2003, and that eight additional jackups are to be completed by 2005. Of the eight jackups to be completed, three are being built with a new Rowan Companies design specifically introduced for deep shelf drilling in the shallow water of the Gulf of Mexico (Offshore, July 2003). The outlook of the offshore industry shows increased growth in deepwater drilling. Three companies are reported as having deepwater semi-submersibles completed by 2004. The projections predict that up to 67% of oil production and 27% of gas production will come from deepwater drilling by 2005. (Drilling Contractor, Nov/Dec 2001).

Since jackups and semi-submersibles are among the most frequent MODUs to have CWIS intake rates that would meet proposed rule criteria, EPA focuses on these as an indication of how many MODUs might be built with CWIS intake rates of concern. Given that 22 jackups are expected to be completed over the time period of 2003-2005 (three years) (Drilling Contractor, 2003b), EPA assumes seven jackups might be built each year during the time frame of the economic analysis; of this group (based on the assumption that half of all new MODUs would meet proposed rule criteria, discussed above) EPA assumes four of these would be affected by the 316(b) requirements. It is further assumed that about one semi-submersible will be built per year. To be conservative, EPA assumes each of these semi-submersibles would meet proposed rule criteria. Drill ships may also be constructed during the time frame of the analysis, but there are currently very few drill ships operating in the GOM. Only 12 out of a total 384 MODUs operating in the GOM (3%) are drill ships. EPA conservatively assumes three drill ships might be constructed over the entire 20-year time frame of the analysis, all of which are assumed to meet proposed rule criteria.

The other two types of MODUs (submersibles and barges) are seldom associated with CWIS intake rates meeting proposed rule criteria (U.S. EPA, 2004). EPA assumes no submersibles or barges with total design intake rates meeting proposed rule criteria will be built during the time frame of the analysis. EPA assumes that half the jackups and semi-submersibles will be built with proposed technologies in place to control intake of aquatic species under a two MGD cutoff. The drill ships are assumed to be built with 50 MGD or greater intake rates, and the jackups and semi-submersibles are assumed to be built with intakes having a total intake rate of less than 20 MGD, based on the intake rates of existing MODUs of these types in the survey.

C2-2 OIL AND GAS PRODUCTION PLATFORMS

C2-2.1 Overview

Oil and gas production operations generally take place on platforms or other structures. The primary areas of offshore oil and gas production activity are the GOM, California, and Alaska. In shallow offshore waters, platforms are the typical structure used to support the resource extraction activities. These activities may involve drilling wells, producing oil and gas from wells, separating production streams, gathering and compressing gas, and working over older wells to increase production. Platforms often support buildings for crews, including in some cases, long-term living quarters.

There are several different types of platforms, and non-platform structures used in the GOM. Seven major types of production systems are used in offshore oil and gas production.

- The fixed platform is the most commonly used for shallow-water drilling. It is anchored directly into the seabed with a deck to support living quarters etc. While it is primarily used for shallow water drilling, it is economically feasible for depths up to 1,650 ft.

- The compliant tower is a flexible tower and piled foundation with a conventional deck. The compliant tower differs from the fixed platform in that it can withstand large lateral forces. Therefore, it is effective at greater depths and is typically used in water depths between 1,500 and 3,000 ft.

- The Seastar platform is a floating mini-tension leg platform used for smaller deepwater reserves. It is used in water depths from 600 to 3,500 ft.

- A floating production system (FPS) is a semi-submersible with drilling and production equipment. The FPS can be dynamically positioned using rotating thrusters. The FPS is used at depths from 600 to 6,000 ft.

- Another type of offshore platform is the Tension Leg platform (TLP). It is connected to he sea floor with tension tendons. TLPs are used up to depths of 6,000 ft.

- The Spar platform consists of a large diameter cylinder supporting a deck and is used in water depths up to 3,000 ft.

- The Subsea system can produce single or multiple wells using manifold pipeline systems. The Subsea system is used for production at depths greater than 7,000 ft. (U.S. EPA, 2000). In this system, all well completions are at the seafloor level, with piping leading to production platforms in shallower water or nearby deepwater structures.

C2-2.2 Existing Platforms and Their Associated Firms

EPA's primary sources of data on platforms in most of the regions of concern (GOM and California) are from the Department of the Interior, Minerals Management Service (MMS). MMS collects data on platforms, drilling, and production from all of the platforms located in Federal waters (3 miles offshore in most locations, but 10 miles beyond the Texas shoreline). Early investigations by EPA (U.S. EPA, 2004) indicated that water intakes for cooling waters in near-shore regions of the Gulf (both in the coastal regions and in offshore State waters) appear to be well below 2 MGD. Thus, EPA has focused only on the operations in Federal waters in the GOM. Operations in the coastal subcategory and in State offshore waters of the GOM are therefore considered unlikely to be affected by the rulemaking and are not discussed further.

a. Platforms in the GOM

Early in the process of identifying existing platforms where cooling water intake rates might be in the size range of concern, EPA determined that the largest platforms and those in deepwater locations (1,000 feet of water depth or greater) appeared the likeliest to have CWISs with at least 2 MGD of total flow (ERG, 2003). This finding was based on voluntary data submissions from industry on a number of platforms operating in the GOM (ERG, 2004a, DCN 7-3505). Based on this analysis, EPA divided the analysis in the GOM into several groups–platforms in deep water (in depths of a 1,000 feet of water or more), shallow water platforms (< 1,000 feet) with 20 or more slots available for wells (considered large platforms), and shallow water platforms with fewer than 20 slots (small platforms). These groupings were used to stratify EPA's survey of platforms conducted for the proposed 316(b) Phase III rulemaking.

Using a database compiled by MMS as of June 2003, EPA created a list of platforms located in the Gulf of Mexico. The database was downloaded and counts of structures were noted. Abandoned platforms and platforms without production equipment were eliminated from the platform count. The platforms were then categorized by deepwater and shallow water, and 20+ wells and <20 wells. The counts are presented in Table C2-5. As the table shows, the about 90% of platforms in the GOM are small platforms operating in shallow water. Only a very few structures (generally not the typical fixed platforms) are found in the deepwater regions of the GOM. Currently (2003 data) only 26 are considered built and operational in the MMS database.

Table C2-5: GOM Platform Count

Category			Count
Total Number of Platforms			6,226
Removed Platforms			2,229
Abandoned Platforms			21
Platforms without Production Equipment			1,587
Producing Platforms	Deep	Deepwater	26
	Shallow	>=20 slots	209
		<20 slots	2,194
Total Producing Platforms			2,429

Source: MMS, 2003a.

These platforms are operated by a number of firms of different sizes and types. The potentially affected firms can be divided into two basic categories. The first category consists of the major integrated oil companies, which are characterized by a high degree of vertical integration (i.e., their activities encompass both “upstream” activities—oil exploration, development, and production—and “downstream” activities—transportation, refining, and marketing). The second category of affected firms consists of independents engaged primarily in exploration, development, and production of oil and gas and not typically involved in downstream activities. Some independents are strictly producers of oil and gas, while others maintain some service operations, such as contract drilling and well servicing.

The major integrated oil companies are generally larger than the independents. As a group, the majors typically produce more oil and gas, earn significantly more revenue and income, and have considerably more assets and greater financial resources than most independents. Furthermore, majors tend to be relatively homogeneous in terms of size and corporate structure. All majors are considered large firms under the Regulatory Flexibility Act (RFA) guidelines and generally are C corporations (i.e., the corporation pays income taxes). Independents can vary greatly by size and corporate structure. Larger independents tend to be C corporations; small firms might also pay corporate taxes, but they also can be organized as S corporations (which elect to be taxed at the shareholder level rather than the corporate level under subchapter S of the Internal Revenue Code). Small firms also might be organized as limited partnerships, sole proprietorships, etc., whose owners, not the firms, pay taxes.

The proportions of majors and independents operating in the State offshore in the GOM has been changing over the last dozen or more years. Except for the deepwater GOM, majors have generally been disinvesting in the Gulf, selling their platforms to independents. Independents, because of their different cost structures and risk profiles can often operate marginal platforms far longer than majors. Independents often have lower overheads. Furthermore, many independents who operate platforms purchased from majors do not engage as extensively in exploration, thus they may be tolerant of lower returns, since their risks are lower.

Table C2-6 summarizes the information developed using the MMS databases, listing the firms operating in the Federal GOM. To identify parent companies and/or recent changes in ownership, EPA again used SEC’s Edgar database. Note that EPA’s analysis is based primarily on the status of the industry as of year end 2002, reported in March 2003 (the date by which most firms must submit their 10K reports). Mergers and acquisitions continue to occur among this group of firms.[3]

Table C2-6: Operators and Parent Companies of GOM Platforms

Operator Company	Parent Company
AEDC USA Inc	AOC Energy Development Company Ltd.
AGIP Petroleum Co Inc	AGIP Petroleum Co Inc
AGIP Petroleum Exploration Co Inc	AGIP Petroleum Co Inc
Amerada Hess Corporation	Amerada Hess Corporation
Anadarko E&P Company LP	Anadarko Petroleum Corporation
Anadarko Petroleum Corporation	Anadarko Petroleum Corporation
Apache Corporation	Apache Corporation
Apex Oil & Gas Inc	Apex Oil & Gas Inc
Arena Offshore LLC	Arena Resources
ATP Oil & Gas Corporation	ATP Oil & Gas Corporation
B T Operating Co	B T Operating Co
Barrett Resources Corporation	Williams Companies Inc
BHP Billiton Petroleum (Americas) Inc	BHP Billiton Petroleum (Americas) Inc
Bois D'arc Offshore Ltd	Bois D'arc Offshore Ltd
BP America Production Company	BP PLC
BP Exploration & Production Inc	BP PLC
Burlington Resources Offshore Inc	Burlington Resources Inc
Cairn Energy USA Inc	Cairn Energy USA Inc
Callon Petroleum Operating Company	Callon Petroleum Co
Calpine Natural Gas Company	Calpine Corp
Century Exploration Company	Century Exploration Company
Chevron USA Inc	ChevronTexaco
CNG Pipeline Company	Dominion Resources Inc
Cockrell Oil Corporation	Cockrell Oil Corporation
Comstock Offshore LLC	Comstock Resources
Conn Energy Inc	Conn Energy Inc
ConocoPhillips Company	ConocoPhillips Company
Contour Energy E & P LLC	Contour Energy Co

[3] Note that all corporate ties could not be identified. Corporate parents are not obliged to list all subsidiaries, only significant subsidiaries. Where no corporate ties could be identified, EPA assumed the operator listed was at the highest level of corporate organization.

Table C2-6: Operators and Parent Companies of GOM Platforms

Operator Company	Parent Company
Delos Offshore Company LLC	El Paso Corp.
Denbury Offshore Inc	Denbury Resources
Devon Energy Production Company LP	Ocean Energy Inc
Devon SFS Operating Inc	Ocean Energy Inc
Dominion Exploration & Production Inc	Dominion Resources Inc
Duke Energy Field Services LP	Duke Energy Co
Dunhill Resources Inc	Dunhill Resources Inc
Dynegy Midstream Services Limited Partnership	Dynagy Inc
EEX Corporation	Newfield Exploration Company
El Paso Production Company	El Paso Corp.
El Paso Production Gom Inc	El Paso Corp.
El Paso Production Oil & Gas Company	El Paso Corp.
Energy Partners Ltd	Energy Partners Ltd
Energy Resource Technology Inc	Energy Resource Technology Inc
EOG Resources Inc	EOG Resources Inc
Equilon Pipeline Company LLC	Equilon Enterprises LLC[a]
ExxonMobil Corporation	Exxon Mobil Corporation
Fairways Specialty Sales & Service Inc	Fairways Specialty Sales & Service Inc
Flextrend Development Company LLC	El Paso Corp.
Forest Oil Corporation	Forest Oil Corporation
Freeport McMoran Sulphur LLC	McMoran Exploration Co
Garden Banks Gas Pipeline LLC	Garden Banks Gas Pipeline LLC
GOM Shelf LLC	GOM Shelf LLC
Gryphon Exploration Company	Gryphon Exploration Company
Hall-Houston Oil Company	Hall-Houston Oil Company
HC Resources LLC	HC Resources LLC
Houston Exploration Company	Houston Exploration Company
Hunt Oil Company	Hunt Oil Company
Hunt Petroleum (AEC) Inc	Hunt Petroleum (AEC) Inc
J M Huber Corporation	J M Huber Corporation
J Ray McDermott Technology Inc	McDermott International Inc.
Juniper Energy LP	Juniper Energy LP
Kerr-McGee Corporation	Kerr-McGee Corporation
Kerr-McGee Oil & Gas Corporation	Kerr-McGee Corporation

Table C2-6: Operators and Parent Companies of GOM Platforms

Operator Company	Parent Company
Linder Oil Company, a Partnership	Linder Oil Company, a Partnership
LLOG Exploration Offshore Inc	Amerada Hess Corporation
Louis Dreyfus Natural Gas Corp	Dominion Resources Inc
Magnum Hunter Production Inc	Magnum Hunter Production Inc
Manta Ray Offshore Gathering Company LLC	El Paso Corp.
Marathon Oil Company	Marathon Oil Corp
Maritech Resources, Inc	Maritech Resources, Inc
Matrix Oil & Gas, Inc	Matrix Oil & Gas, Inc
McMoRan Oil & Gas LLC	McMoRan Exploration Co
Merit Energy Company	Merit Energy Company
Millennium Offshore Group Inc	Millennium Offshore Group Inc
Mission Resources Corporation	Mission Resources Corporation
Mobil Oil Exploration & Production	ExxonMobil Corporation
Murphy Exploration & Production	Murphy Oil Corporation
Murphy Exploration & Production Company - USA	Murphy Oil Corporation
NCX Company LLC	NCX Company LLC
Newfield Exploration Company	Newfield Exploration Company
Nexen Petroleum USA Inc	Nexen Petroleum USA Inc
Nippon Oil Exploration U S A	Nippon Oil Exploration U S A
Ocean Energy Inc	Ocean Energy Inc
Offshore Energy I LLC	Offshore Energy I LLC
Panaco Inc	Panaco Inc
Petro Ventures Inc	Petro Ventures Inc
Petrobras America Inc	Petrobras America Inc
Petroquest Energy LLC	Petroquest Energy LLC
Pioneer Natural Resources USA Inc	Pioneer Natural Resources Co
Pogo Producing Company	Pogo Producing Company
PRS Offshore LP	PRS Offshore LP
Remington Oil and Gas Corporation	Remington Oil and Gas Corporation
Samedan Oil Corporation	Noble Energy Inc
Scana Petroleum Resources Inc	Scana Petroleum Resources Inc
Seagull EnergyE&P Inc	Ocean Energy Inc
Seneca Resources Corporation	National Fuel Gas Company
Shell Frontier Oil & Gas Inc	Royal Dutch/Shell Group

Table C2-6: Operators and Parent Companies of GOM Platforms

Operator Company	Parent Company
Shell Offshore Inc	Royal Dutch/Shell Group
Shell Oil Company	Royal Dutch/Shell Group
Spinnaker Exploration Company LLC	Spinnaker Exploration Company LLC
St Mary Energy Company	St Mary Land & Exploration Co
Stone Energy Corporation	Stone Energy Corporation
Tarpon Offshore LP	Tarpon Offshore LP
Taylor Energy Company	Taylor Energy Company
TDC Energy Corporation	TDC Energy LLC
TDC Energy LLC	TDC Energy LLC
Texaco Exploration and Prod	ChevronTexaco
The Louisiana Land and Exploration Company	Burlington Resources Inc
Torch Energy Services Inc	Torch Offshore
TotalFinaElf E&P USA Inc	TotalFinaElf E&P USA Inc
Transcontinental Gas Pipe Line Corporation	Transcontinental Gas Pipe Line Corporation
Transworld Exploration and Production Inc	Transworld Exploration and Production Inc
Tri-Union Development Corporation	Tri-Union Development Corporation
UMC Pipeline Corporation	UMC Pipeline Corporation
Union Oil Company of California	Unocal Corp.
Unocal Pipeline Company	Unocal Corp.
Vastar Resources Inc.	BP PLC
Vintage Petroleum Inc	Vintage Petroleum Inc
W & T Offshore Inc	W & T Offshore Inc
Walter Oil & Gas Corporation	Walter Oil & Gas Corporation
Westport Oil and Gas Company LP	Westport Oil and Gas Company LP
Westport Resources Corporation	Westport Resources Corporation
WFS - Offshore Gathering Company	Williams Companies Inc
William G Helis Company LLC	William G Helis Company LLC
Williams Field Services - Gulf Coast Company LP	Williams Companies Inc
Williams Production RMT Company	Williams Companies Inc

[a] Joint venture between Royal Dutch/Shell Group and Texaco currently operating as Shell Oil Products U.S. Shell bought Texaco's interests in 2002 (Alexander's Oil and Gas Connections, 2002).

Source: MMS, 2003a; SEC, 2003.

It is important to note that companies may share ownership of a platform. In general, the company listed as the operator in the MMS databases is the owner or largest share holder of the platform, but this is not always the case. The economic analyses in this report, however, make the simplifying assumption that only one firm owns a platform. In reality, the impacts from regulatory costs to a platform might be shared by several firms.

The same methodology used to identify small firms in the MODU profile (Section C2-1) is used for this profile. Table C2-7 lists the numbers of firms in the GOM by their NAICS definition.[4] Also listed is the SIC code, which is the identifier used in the 10K reports. In the table, NAICS and SICs are mapped in the key industry sectors represented by firms operating in the GOM.

Table C2-7: Count of Firms by SIC and NAICS Code

SIC code	NAICS code	NAICS Title	SBA Size Standard	GOM Number of Firms	
				Small	Large
1311	211111	Crude Petroleum and Natural Gas Extraction	500 employees	19	12
1389	213112	Support Activities for Oil and Gas Operations	$7.5 million in revenues	1	1
2911	324110	Petroleum Refineries	1,500 employees	0	8
3443		Several industries	750 employees[a]	0	1
4911	221112	Fossil Fuel Electric Power Generation	4.0 million megawatt hours	0	3
4922	486210	Pipeline Transportation of Natural Gas	$6.0 million in revenues	1	3
4924	221210	Natural Gas Distribution	500 employees	0	1

[a] Highest number of employees defining small among the group of industries that 3443 has been split into.
Note: Does not include 37 firms considered domestic and 10 foreign firms for which NAICS or SIC codes could not be located in publicly available data.

Source: SEC, 2003, 13 CFR Part 121.

As Table C2-7 shows, the predominant firm types operating in the GOM are those in the oil and gas extraction NAICS and the refineries NAICS. A total of 21 firms were identified as small. Another 37 non-foreign firms could not be identified as small or large thus are considered small for purposes of analysis. As was done for MODU firms, all foreign firms were assumed to be large. Once EPA accounted for these relationships and transactions, EPA's count of potentially affected firms in the Gulf of Mexico becomes 96 firms, of which 10 are listed as majors, and 10 firms are identified as foreign owned (not including Shell Oil, a major that is affiliated with Royal Dutch/Shell Group, but which reports to SEC). Non-foreign non-majors total 76 firms, including those not previously identified as majors or independents (U.S. EPA, 2000).

Table C2-8 shows the firms considered potentially affected firms operating in the Federal GOM and their relevant financial data. These data include number of employees, assets, liabilities, and revenues, along with several ratios that provide a general indication of financial health. Note that blank lines in Table C2-8 indicate firms that are likely to be privately held or are foreign and for which no public data have been located.

[4] The North American Industry Classification System (NAICS) supercedes the Standard Industrial Classification (SIC) codes, however, the transition to the new system is still in progress.

The ratios used to establish company financial status are profitability ratios, namely: return on assets, return on equity, and profit margin. As described earlier, these three financial indicators are calculated as the ratio of the net income to the total assets, stockholders' equity, and net sales respectively. While individually these ratios only tell a part of the financial stability of a company, when analyzed together, they give a much clearer picture of a company's financial health.

Of these operators in the Gulf, EPA has identified 58 (60%) that either meet the SBA's definition of a small business (which for the oil and gas extraction industry is defined as a business entity with 500 or fewer employees or for the oil field service industry as a business entity with $5 million or less in annual revenues) or that cannot be identified as large because their employment or revenue figures are not known. These latter firms might be privately owned, or they do not file with the SEC as an independent firm but their parent company could not be identified. Most of these firms, however, are not likely to be involved in constructing new oil and gas platforms that would be subject to Phase III regulation, as discussed below. Small firms that might be affected by the rule are discussed in more detail in *Chapter D1: Regulatory Flexibility Analysis*.

Table C2-8 also presents summary financial ratios for the large and small firms. Among publicly held firms, median return on assets for the group is 2.65%, median return on equity is 4.89%, and median profit margin (net income/revenues) is 5.71%, according to 2002 financial data. Among these publicly held firms, 35 out of 48 firms, or 73%, reported positive net income for 2002.

b. California Platforms

California has a total of 33 platforms; 9 located in State waters and 24 in State waters. Six companies operate platforms in State water off the California shore: Aera Energy LLC, Arguello, Inc., ExxonMobil, Nuevo Energy, Pacific Operators Offshore, and Venoco Inc. Two deepwater (>1,000 ft.) platforms operate in CA State waters, both of which are owned by ExxonMobil. Financial information for these companies is presented in Table C2-9 Aera Energy LLC, ExxonMobil, Nuevo Energy, and Venoco Inc. also operate platforms in State waters along with two additional companies (Occidental Petroleum Co. and Rincon Island Limited Partnership). The maximum depth of platform drilling in State waters is 211 ft. The maximum depth in State waters is 1,198 ft. ExxonMobil and Shell (owning the majority of the joint venture company, Aera Energy) are the only majors operating in California State waters. The other companies are all unidentified. Nuevo Energy Company and Arguello (a subsidiary of Plains Exploration and Production) are the only companies specifically identified as a small business, with 412 employees and 354 employees (at the parent companies), respectively. Venoco Pacific Operators, and Rincon Island, LP, are assumed small for lack of data. One of the firms in California is classified as NAICS 324110 (SIC 2911), Petroleum Refineries, one firm is classified as NAICS 422720 (SIC 5172), Petroleum and Petroleum Products Wholesale, and two additional firms are listed as NAICS 211111 (SIC 1311), Crude Petroleum and Natural Gas Extraction. The NAICS classification of the remaining firms is undetermined.

Table C2-8: Financial Conditions Among GOM Firms

Company Name	Size	Type	Number of Employees	Assets ($000)	Equity ($000)	Revenues ($000)	Net Income ($000)	Return on Assets	Return on Equity	Profit Margin
AOC Energy Development Corp.	Large**	Foreign								
AGIP Petroleum Co Inc	Large**	Foreign								
Amerada Hess Corporation	Large	Major	11,662	$2,455,425	$1,608,133					
Anadarko Petroleum Corp.	Large	Independent	3,800	$1,280,000		$3,860,000	$825,000	64.45%		21.37%
Apache Corporation	Large	Independent	1,958	$9,459,851	$544,000	$2,559,873	$554,329	5.86%	101.90%	21.65%
Apex Oil & Gas Inc	Small*	Other								
Arena Resources	Small	Independent	5	$6,050	$5,125	$1,657	$403	6.66%	7.86%	24.32%
ATP Oil & Gas Corporation	Small	Independent	53	$182,055	$38,547	$94,423	($4,700)	-2.58%	-12.19%	-4.98%
B T Operating Co	Small*	Other								
BHP Billiton Petroleum (Americas) Inc	Large**	Foreign		$2,865,000		$2,815,000	$718,000	25.06%		25.51%
Bois D'arc Offshore Ltd	Small*	Other								
BP PLC	Large	Major	73,350	$164,090,000		$178,721,000	$10,422,000	6.35%		5.83%
Burlington Resources Offshore Inc	Large	Independent	2,003	$10,645,000	$3,832,000	$2,964,000	$454,000	4.26%	11.85%	15.32%
Cairn Energy USA Inc	Large**	Foreign	19	$696,100		$70,000	$29,100	4.18%		41.57%
Callon Petroleum Operating Company	Small	Independent	100	$410,613	$140,960	$67,108	($1,671)	-0.41%	-1.19%	-2.49%
Calpine Corporation	Large	Other	3,353	$23,266,992		$7,457,899	$118,618	0.51%		1.59%
Century Exploration Co.	Small*	Independent								
ChevronTexaco	Large	Major	53,014	$77,359,000	$31,604,000	$99,049,000	$1,132,000	1.46%	3.58%	1.14%
Cockrell Oil Corporation	Small*	Independent								
Comstock Resources	Small	Independent	62	$683,071	$215,662					
Conn Energy Inc	Small*	Other								
ConocoPhillips Company	Large	Major	>10,000	$76,836,000		$56,748,000	($295,000)	-0.38%		-0.52%
Contour Energy E & P	Small	Independent	47							

Table C2-8: Financial Conditions Among GOM Firms

Company Name	Size	Type	Number of Employees	Assets ($000)	Equity ($000)	Revenues ($000)	Net Income ($000)	Return on Assets	Return on Equity	Profit Margin
LLC										
Denbury Resources Inc	Small	Independent	356	$895,292	$366,797	$285,152	$46,795	5.23%	12.76%	16.41%
Dominion Resources	Large	Other	17,000	$37,909,000		$10,218,000	$1,362,000	3.59%		13.33%
Duke Energy Co.	Large	Other	22,000	$60,966,000		$15,663,000	$1,034,000	1.70%		6.60%
Dunhill Resources Inc	Small*	Other								
Dynegy Inc.	Large	Other	1,524	$20,030,000	$2,087,000	$5,553,000	($1,955,000)	-9.76%	-93.68%	-35.21%
El Paso Corp.	Large	Other	11,885	$46,224,000	$8,377,000	$12,194,000				
Energy Partners Ltd	Small	Independent	132	$384,220	$191,922	$134,031	($8,799)	-2.29%	-4.58%	-6.56%
Energy Resource Technology Inc	Small*	Independent								
EOG Resources Inc	Large	Major	1,000	$3,814,006	$1,672,395	$1,095,036	$87,173	2.29%	5.21%	7.96%
Equilon Enterprises	Large	Major								
ExxonMobil Corporation	Large	Major	92,500	$153,000,000	$74,597,000	$205,000,000	$11,460,000	7.49%	15.36%	5.59%
Fairways Specialty Sales & Service Inc	Small*	Other								
Forest Oil Corporation	Small	Independent	493	$1,924,681	$921,211	$475,694				
Garden Banks Gas Pipeline LLC	Small*	Other								
GOM Shelf LLC	Small*	Other								
Gryphon Exploration Company	Small*	Independent								
Hall-Houston Oil Company	Small*	Independent								
HC Resources LLC	Small*	Other								
Houston Exploration Company	Large	Independent	145	$1,138,816	$592,789	$345,381	$70,494	6.19%	11.89%	20.41%
Hunt Oil Company	Small*	Independent								
Hunt Petroleum (Aec) Inc	Small*	Independent								
J M Huber Corporation	Small*	Independent								

Table C2-8: Financial Conditions Among GOM Firms

Company Name	Size	Type	Number of Employees	Assets ($000)	Equity ($000)	Revenues ($000)	Net Income ($000)	Return on Assets	Return on Equity	Profit Margin
Juniper Energy LP	Small*	Other								
Kerr-McGee Corporation	Large	Independent	4,470	$9,909,000	$2,536,000	$2,540,000	($485,000)	-4.89%	-19.12%	-19.09%
Linder Oil Company, a Partnership	Small*	Other								
Magnum Hunter Production Inc	Small	Independent	221	$251,069	$72,152	$48,834	($3,512)	-1.40%	-4.87%	-7.19%
Marathon Oil Company	Large	Major	28,166	$4,479,000	$5,082,000	$31,720,000	$516,000	11.52%	10.15%	1.63%
Maritech Resources Inc	Small*	Other								
Matrix Oil and Gas	Small*	Other								
McDermott International Inc	Large	Other		$128,171	($416,757)	$1,748,681	($776,394)	-605.75%	186.29%	-44.40%
McMoRan Exploration Co.	Small	Independent	18	$72,448	($64,431)	$43,768	$17,041	23.52%	-26.45%	38.93%
Merit Energy Company	Large**	Foreign								
Millennium Offshore Group Inc	Large**	Foreign								
Mission Resources Corp.	Small	Independent	90	$342,404	$65,377	$105,464	($38,484)	-11.24%	-58.86%	-36.49%
Murphy Oil Company	Large	Major		$3,885,775	$1,593,553	$3,966,516	$111,508	2.87%	7.00%	2.81%
National Fuel Gas Company	Large	Other								
NCX Company LLC	Small*	Independent								
Newfield Exploration Company	Small	Independent	488	$2,315,753	$1,009,231	$661,750	$73,847	3.19%	7.32%	11.16%
Nexen Petroleum USA Inc	Large**	Foreign	1,767	$41,548,000		$1,971,300	$287,200	0.69%		14.57%
Nippon Oil Exploration U S A	Large**	Foreign		$11,076,000		$34,894,000	$269,000	2.43%		0.77%
Noble Corp.	Large	Independent	624	$3,065,714	$1,989,210	$986,356	$209,503	6.83%	10.53%	21.24%
Ocean Energy Inc	Large	Independent	948	$131,613	($825)	$47,483	$2,227	1.69%	-269.94%	4.69%
Offshore Energy I LLC	Small*	Independent								
Panaco Inc	Small	Independent	21							

Table C2-8: Financial Conditions Among GOM Firms

Company Name	Size	Type	Number of Employees	Assets ($000)	Equity ($000)	Revenues ($000)	Net Income ($000)	Return on Assets	Return on Equity	Profit Margin
Petro Ventures Inc	Small*	Other								
Petrobras America Inc	Large**	Foreign								
Petroquest Energy LLC	Small	Independent	57	$132,063	$97,770	$48,141	$2,307	1.75%	2.36%	4.79%
Pioneer Natural Resources USA Inc	Large	Independent	979	$3,455,100	$1,374,900	$717,400	$26,700	0.77%	1.94%	3.72%
Pogo Producing Company	Small	Independent	219	$2,426,608	$824,885	$605,500	$87,954	3.62%	10.66%	14.53%
PRS Offshore LP	Small*	Independent								
Remington Oil and Gas Corporation	Small	Independent	29	$288,993	$193,660	$104,186	$11,332	3.92%	5.85%	10.88%
Royal Dutch/Shell Group	Large	Major Foreign	111,000	$152,691,000		$235,598,000	$9,419,000	6.17%		4.00%
Scana Petroleum Resources Inc	Small*	Other								
Spinnaker Exploration Company LLC	Small	Independent	65	$842,715	$692,977	$188,326	$31,579	3.75%	4.56%	16.77%
St Mary Energy Company	Small	Independent	185	$537,139	$299,513	$196,394	$27,560	5.13%	9.20%	14.03%
Stone Energy Corporation	Small	Independent	210	$1,179,371	$577,488	$377,495	$85,229	7.23%	14.76%	22.58%
Tarpon Offshore LP	Small*	Other								
Taylor Energy Company	Small*	Independent								
TDC Energy Corporation LLC	Small*	Independent								
Torch Offshore Inc.	Small	Other	362	$101,904	$79,867	$67,990	$395	0.39%	0.49%	0.58%
TotalFinaElf E&P USA Inc	Large**	Foreign								
Transcontinental Gas Pipe Line Corporation	Large	Other	1,261	$4,969,532	$2,476,513	$1,276,282	$163,041	3.28%	6.58%	12.77%
Transworld Exploration and Production Inc	Small*	Other		$12,665,000	$7,141,000	$2,674,000	($3,732,000)	-29.47%	-52.26%	-139.57%
Tri-Union Development Corporation	Small*	Independent								
UMC Pipeline Corporation	Small*	Independent								

Table C2-8: Financial Conditions Among GOM Firms

Company Name	Size	Type	Number of Employees	Assets ($000)	Equity ($000)	Revenues ($000)	Net Income ($000)	Return on Assets	Return on Equity	Profit Margin
Unocal	Large	Independent	6,615	$10,760,000	$3,298,000	$5,297,000	$331,000	3.08%	10.04%	6.25%
Vintage Petroleum Inc	Large	Independent	690	$1,775,804	$570,992	$664,263	($143,664)	-8.09%	-25.16%	-21.63%
W & T Offshore Inc	Small*	Independent								
Walter Oil & Gas Corporation	Small*	Independent								
Westport Oil and Gas Company LP	Small*	Other								
Westport Resources Corporation	Small	Independent	333	$2,233,451	$1,132,006	$400,398	($28,566)	-1.28%	-2.52%	-7.13%
William G Helis Company LLC	Small*	Independent								
Williams Company	Large	Other	7,300	$34,988,500	$5,049,000	$5,608,400	($754,700)	-2.16%	-14.95%	-13.46%

Note: Other is used if no designation for major or independent is provided in U.S. EPA, 2000.

* Presumed small due to lack of data.

** Presumed large - Foreign-owned.

Source: Table C2-6; SEC, 2003; U.S. EPA, 2000.

Table C2-9: Financial Information for Companies Operating Platforms in California Waters ($000)

Company Name	Size	Type	Employees	Total Assets	Equity	Revenues	Net Income
Royal/Dutch Shell (Aera Energy)	Large	Major	111,000	$152,691,000		$235,598,000	$9,419,000
Plains Exploration and Production (Arguello)	Small	Other	354	$550,880	$173,820	$178,038	$26,237
ExxonMobil	Large	Major	92,500	$153,000,000	$74,597,000	$205,000,000	$11,460,000
Nuevo Energy Company	Small	Independent	412	$855,171	$174,276	$323,056	$12,275
Pacific Operators Offshore	Small[a]	Other					
Venoco, Inc.	Small[a]	Independent					
Rincon Island Limited Partnership	Small[a]	Other					
Occidental Petroleum Corp.	Large	Major	7,244	$16,548,000	$6,318,000	$7,491,000	$989,000

[a] Presumed small due to lack of data.

Source: ERG, 2004c; SEC, 2003; U.S. EPA, 2000.

c. Alaska Operations

There are two major regions of oil and gas production in Alaska. The first, the North Slope region, operates generally from onshore locations or on gravel islands. Platforms are not used here.

The second region, Cook Inlet, Alaska, is divided into two regions: Upper Cook Inlet, which is in State waters and is governed by the Coastal Oil and Gas effluent guidelines; and Lower Cook Inlet, which is considered Federal OCS waters and is governed by the Offshore Oil and Gas Effluent Guidelines. This section refers primarily to Upper Cook Inlet.

There are 16 platforms and 3 onshore production facilities in Cook Inlet, Alaska, of which two platforms have ceased operation and two platforms have suspended operation. The platforms are owned by five companies: Forest Oil Corporation, Marathon Oil Corp., ConocoPhillips, XTO Energy, and Unocal Corp. Marathon owns the two out-of-operation platforms and is not considered a potentially affected firm in Alaska. Unocal Corp. operates the majority of platforms in the Cook Inlet region, with 10 platforms and 2 onshore treatment facilities. Only one company operating in Cook Inlet waters, Forest Oil, is an independent and considered a small business. XTO is also an independent, but is a large business. The remaining operators are all listed as majors, as is the operator (BP) of the Duck Island structure in the Beaufort Sea (North Slope). Two of the firms in Alaska are listed under NAICS 324110 (SIC 2911), Petroleum Refineries, and the three additional firms are listed as NAICS 211111 (SIC 1311), Crude Petroleum and Natural Gas Extraction. Financial data for these firms are presented in Table C2-10

The Department of Fish and Game in Alaska developed a standard lease requirement for all water intake pumps to be fitted with a screened enclosure. The requirement further States that the water intake at the surface of the screen enclosure should not exceed 0.1 feet per second. For the purposes of the regulatory analysis, therefore, any new platforms in the Cook Inlet or the North Slope regions are considered to be potentially affected by the 316(b) requirements for entrainment, but not impingement, since the Alaska requirement meets or exceeds proposed 316(b) impingement standards.

Table C2-10: Financial Information for Companies Operating Platforms in Alaska ($000)

Company Name	Size	Type	Employees	Tot. Assets	Equity	Revenues	Net Income
Forest Oil	Small	Independent	493	$1,924,681	$921,211	$475,694	$21,276
BP	Large	Major	73,350	$164,090,000		$178,721,000	$10,422,000
ConocoPhillips	Large	Major	>10,000	$76,836,000		$56,748,000	($295,000)
XTO Energy	Large	Independent	867	$2,648,193	$907,786	$810,163	$186,100
Unocal	Large	Major	6,615	$10,760,000	$3,298,000	$5,297,000	$331,000

Source: ERG, 2004c; SEC, 2003; U.S. EPA, 2000.

C2-2.3 Existing Platforms with Intake Rates Meeting Proposed Rule Criteria

a. Overview of Existing Platforms as Model for New Platforms Subject to Phase III Regulation

Very few existing platforms appear to have CWISs with intake rates that meet the proposed rule's criteria. Most of the existing platforms with CWISs of this size are located in the deepwaters of GOM and in California and Alaska waters (Cook Inlet). Using the same approach as outlined for determining existing MODUs with CWIS intake rates meeting proposed rule criteria, EPA makes the following estimates, using the survey conducted for the oil and gas sectors to support this rulemaking and voluntary data submitted by industry. See also ERG (2004b).

EPA stratified the survey in the GOM into three strata: deepwater, shallow large (20+ slot platforms), and shallow small (fewer than 20 slots).

The survey universe of deepwater structures was 24 (two structures were removed from the universe prior to the survey because their CWIS intake rates were known to be less than 2 MGD). For the survey, EPA sampled four facilities. There were no non-respondents. Only one of the four reported data showing them to have CWIS intake rates meeting proposed rule criteria. Thus EPA estimated that six deepwater structures would have CWIS intake rates meeting proposed rule criteria (24 divided by 4 is a weight of 6; with one respondent reporting an intake rate of 2 MGD or more, this produces an estimate of six total new structures meeting proposed rule criteria). However, earlier data (see ERG, 2004a) indicate that eight structures in the deepwater have CWIS intake rates meeting proposed rule criteria. EPA used the higher number of structures to estimate the proportion of existing structures with CWISs meeting the proposed rule criteria to total structures in the deepwater. Given eight structures meeting proposed rule criteria and 24 total structures, EPA believes that about 1/3 of deepwater structures to be built will be equipped with intakes meeting the proposed rule's criteria. Only one existing deepwater structure has a total intake rate of over 20 MGD, and none have a total rate of over 50 MGD. All firms currently operating multi-well structures in the deepwater GOM with CWIS rates that meet criteria are large.

For shallow water large platforms, EPA determined that existing 206 exluding platforms were either known to have CWISs with intake rates meeting proposed rule criteria or their intake rates were unknown (an additional 3 platforms were known to have CWIS intake rates less than 2 MGD and were dropped from the sampling frame). EPA sampled 33 platforms among the large platform group. Three of these were nonrespondents. No additional platforms with intake rates meeting proposed rule criteria were detected using the survey. The nonrespondents were thus assumed also to have CWIS intake rates not meeting proposed rule criteria. Four platforms, however, were known to have CWISs meeting proposed rule criteria based on earlier data (see ERG, 2004a). None of these were sampled. EPA therefore assumes only these four platforms have intake rates meeting proposed rule criteria. These platforms are owned by large firms (ExxonMobil and Marathon). Thus EPA assumes that if any large platforms with CWIS intake rates meeting proposed rule criteria were to be built, they would be built by large firms.

For shallow small platforms, EPA determined that 2,194 platforms were in the universe of platforms in the Federal GOM. The vast majority of these platforms have unknown CWIS intake rates. Four such platforms were identified prior to EPA's Phase III Survey as having CWIS intake rates exceeding 2 MGD (ERG, 2004a). None of these was sampled. A total of 18 platforms with unknown CWIS intake rates were sampled (all responded), but EPA determined that none of the sampled platforms had total design flow rates meeting proposed rule criteria. Although this is a very small sample, this finding is bolstered by EPA's observations that platforms in State waters are unlikely to have CWIS with intake rates totaling 2 MGD or more (ERG, 2004a). Platforms in State waters and small platforms in Federal waters are generally similar structures. EPA therefore assumes that only four small platforms located in the shallow water GOM have CWIS intakes meeting proposed rule criteria. These four platforms are owned by ExxonMobil and BP, thus no small firms are estimated likely to build platforms with greater than 2 MGD intake rates in shallow water.

In the GOM, therefore, EPA estimates that a total of 16 existing platforms have CWIS intake rates meeting proposed rule criteria. All are owned by large firms, and most operate in the deepwater regions.

In California, EPA determined that 20 platforms either have CWIS intake rates totaling 2 MGD or more or their CWIS intake rates were unknown (13 platforms with known intake rates were eliminated from the sampling frame because their total intake was less than 2 MGD). EPA sampled 3 of these 20 platforms. Only one was found to have an intake rate meeting proposed rule criteria. EPA thus assumes seven existing platforms in California have total intake rates meeting proposed rule criteria (20 divided by 3 is a weight of 6.7, which yields 7 platforms weighted). A total of six platforms are known from earlier data (see ERG, 2004a) to have intakes rates meeting proposed rule criteria, including the surveyed platform. Three have intake rates greater than 20 MGD but less than 50 MGD. Of the six platforms with flow data showing rates meeting proposed rule criteria, three of these are owned by a small business (Plains Exploration and Production/Arguello). The remainder are owned by large businesses (Aera Energy, a joint venture between Shell and ExxonMobil, and ExxonMobil).

In Alaska, EPA determined that 19 platforms/production facilities are in the survey universe (one platform was known to have a total CWIS intake rate of less than 2 MGD and was dropped from the sampling frame). EPA sampled two platforms, but only one was determined to have a CWIS intake rate meeting proposed rule criteria. EPA therefore estimates that there are 10 platforms in Alaska with intakes that meet proposed rule criteria (19/2 is a weight of 9.5). Five of these (all located in Cook Inlet) have CWIS data showing them to have CWISs meeting proposed rule criteria (ERG, 2004a). Of these structures with known CWISs of this size, all are platforms owned by Unocal. Based on this, EPA might assume no small businesses currently operating would be affected in Alaska. However, the most recently built platform in Cook Inlet, Osprey, was constructed by a small firm (Osprey's CWIS intake rates are unknown). To be conservative, EPA assumes that a small firm, much like Forest Oil (Osprey's owner), might be the type of firm to build a new structure in Alaska and such a structure might have CWIS intake rates meeting proposed rule criteria. However, it is also entirely likely that no such structures will be built within the time frame of the analysis.

In summary, there are 16 platforms in the GOM, seven platforms in California, and 10 platforms in Alaska, for a total of 33 existing platforms that meet proposed rule criteria. Of these, three platforms or structures (one in the deepwater and two in California) have CWIS intake rates greater than 20 MGD, and one platform (California) has an intake rate greater than 30 MGD. No platforms have CWIS intake rates exceeding 50 MGD.

b. Current Oil and Gas Production Levels and Trends

In 2002, 555 million bbls of oil and 4.5 million MMcf of gas were produced in the GOM. Fifty nine% of all oil production in the GOM now comes from deepwater wells (MMS, 2003b). MMS has been using incentives such as royalty relief to promote drilling of deep gas wells in GOM over the past few years. In recent years, the drilling of such wells has increased and trends show a continuation of deep gas drilling and exploration in GOM. As technology advances and more deep gas wells are drilled, reserve estimates are being revised as more gas is presumed recoverable. Deep gas wells in the GOM consist of deepwater drilling and deep shelf drilling in shallow waters. Deep shelf gas production increased by 137 Bcf from 2000 to 2002. Approximately 20% of all GOM exploration drilling was at greater than 15,000 ft. at the end of 2003. As the industry gains more experience in deep gas drilling, and the technology continues to advance, experts predict that this trend will continue to be a substantial percentage of gas exploration and production in GOM (Drilling Contractor, Jan./Feb. 2004).

Standard & Poor's annual Report Card of the Oil and Gas industry in 2003 predicted that oil prices would average approximately $19 per barrel, and that natural gas prices would average $3 per million Btu (MMBtu) (S&P, 2003). These price estimates were conservative, especially in light of the potential volatility in the market caused by the war in Iraq. S&P stated factors such as rising non-OPEC production, slow economic growth, and the resumption of Venezuelan operations as potential factors in lowering oil prices. In 2000, OPEC developed a price band mechanism which would adjust production to keep price baskets within the range of $22/bbl to $28/bbl. OPEC has rarely used the mechanism and prices have fluctuated outside of the determined range a number of times since the band's inception. OPEC has, however, maintained a stable price of $20-$22 per barrel in recent years, (Drilling Contractor, Nov/Dec 2003a). Currently, U.S. crude prices for the benchmark Texas Upper Gulf Coast crude is $27.25 per bbl (OGJ, February 16, 2004). The economic analysis employs long run wellhead oil and gas prices used by 316(b) survey respondents to project future platform financials.

S&P also noted that natural gas in North America (onshore and offshore) has shown a 5% annual decline in production. In 2002, production began well over 20% greater than the 5 year average, but the year ended with production 15% lower than that same mark (S&P, 2003). Similar production trends in Canada, the most important source of natural gas imports for the U.S., create speculation of rising natural gas prices. Recently (February 4, 2004), the Henry Hub gas price (a leading gas benchmark) was $5.20/MMBtu (http://www.wtrg.com/daily/oilandgasspot.html). Despite the current price level, Drilling Contractor predicts that prices will decline over the next two years, falling to a range of $3.50 to $4.50 /MMbtu from 2004 to 2006. (Drilling Contractor, Nov/Dec 2003a). U.S. oil demand is predicted to increase by 1.5% each year while existing fields should deplete at the same rate. The demand for natural gas is predicted to increase as well, albeit at a slower rate (1%).

c. Estimate of Platforms To Be Built That May Be Affected by the Proposal

In the deepwater region, EPA determined, based on MMS data, that approximately 2 to 4 structures are built each year (see Figure C2-1 and Table C2-11). EPA assumes that an average of three such deepwater structures are completed each year. EPA notes that out of 24 total structures in the deepwater as of 2003, 8 are estimated to meet proposed rule criteria, or about a third of the total. EPA thus assumes that one structure per year out of the three installed annually might have intakes meeting proposed rule criteria. Because only one structure currently has a CWIS intake rate of greater than 20 MGD (and none have a CWIS intake rate of more than 30 MGD), EPA assumes that only one structure out of 10 would be built having a CWIS intake rate of 20 MGD or more. This would mean that EPA estimates two structures would be built with these intake rates over the 20-year construction time frame.

All of these structures are assumed to be constructed by large firms. Only large firms have built structures in the deepwater GOM, except for a few subsea completions, which have not been identified as associated with intake rates meeting proposed rule criteria. This scenario is likely to continue, given the resources required to construct deepsea structures, which sometime exceed $1 billion dollars (U.S. EPA, 2000).

Table C2-11: Count of Platform Installations

Year	Deepwater Platforms	Platforms in Shallow Water with Greater than or Equal to 20 Wells	Platforms in Shallow Water with Less than 20 Wells
1993	0	1	26
1994	2	4	57
1995	0	0	42
1996	2	1	63
1997	1	0	55
1998	4	2	60
1999	3	0	36
2000	2	0	55
2001	4	0	60
2002	2	0	66
2003	0	0	15

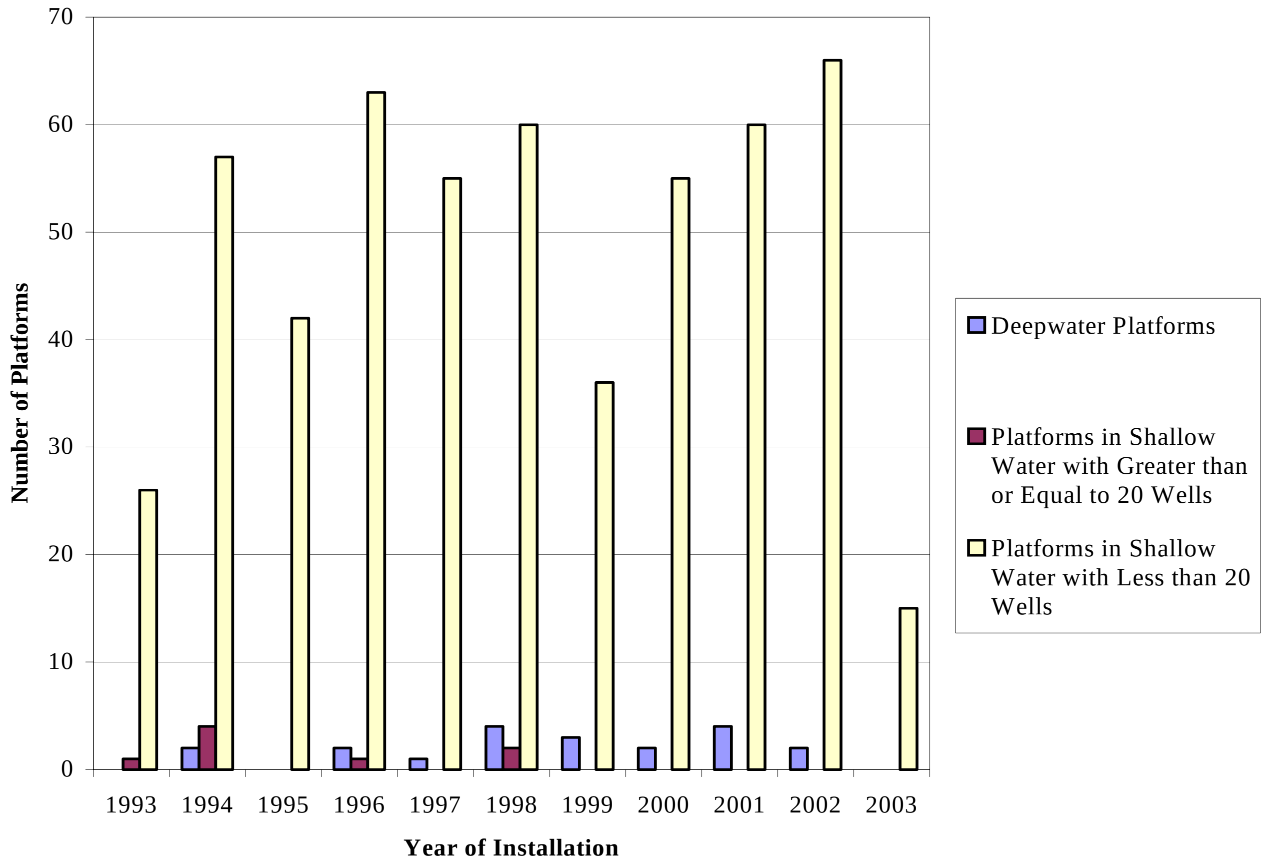
Note: 2003 is a partial year only.

Source: MMS, 2003b.

Among large (20+ slot) platforms, EPA determined that few, if any, such platforms might be built during the time frame of the analysis (see Table C2-11). As the table shows, no platforms of this size have been built over the past 5 years. Given that so few of the existing platforms appear to resemble a new regulated project, EPA assumes no new platforms of this size and with CWIS meeting proposed rule criteria would be constructed.

Among smaller platforms, EPA determined that although they are installed at a rate of about 50-60 per year (see Table C2-11), they are unlikely to install CWIS of the size considered to meet proposed rule criteria. EPA therefore assumes no new smaller platforms constructed in shallow water would be affected by the proposal.

Figure C2-1: Platform Installation by Year



Note: 2003 is a partial year only.

Source: MMS, 2003b.

The Federal offshore waters off the coast of California have been subject to a moratorium on lease sales since 1990. No platforms have been constructed since 1994, and no exploration has been undertaken since 1989. Currently the moratorium extends to 2012. President Bush has dropped opposition to the moratorium and currently has no apparent plans to end the moratorium (Environmental News Network, 2003). The State has indicated to the President that it wishes the moratorium to remain in place, and Governor Schwartzenegger has been pushing for a "permanent ban on all oil drilling in coastal waters." (MSNBC, 2003). There are, however, 40 leases off San Luis Obispo and Santa Barbara Counties that are not subject to the moratorium, and a consortium of oil companies including Aera Energy have announced plans for exploratory drilling. Aera Energy plans to drill in 2004. Political opposition to these plans is enormous, however (Sneed, 2004). Even if exploratory drilling is allowed to take place, any platform construction would occur many years later. Given this strong level of antipathy towards offshore oil and gas development in California, EPA believes that the construction of new platforms, or any new drilling, in either State or Federal California offshore regions is unlikely in the time frame of the analysis.

In Cook Inlet, Alaska, only one new platform has been constructed in recent years. Most new exploration and development in this region takes place from existing infrastructure or from onshore locations using directional drilling, in which wells are drilled both vertically and horizontally to reach potential reserves, sometimes thousands of feet from the top-hole locations. No definitive plans appear to be in place for any new platforms in State waters. In Federal waters, lower Cook Inlet is a source of potential activity, since MMS completed a lease bid in April, 2004. However, given the long lead times between lease bid to operation, it may be relatively unlikely that this lease bid will result in new platforms during the time frame of the analysis in either location. To be conservative, however, EPA assumes one such platform might be constructed in Upper Cook Inlet (State waters) and begin operation during the time frame of analysis. In other Federal areas in the Alaska region, little new activity is underway. BP has dropped plans for its Liberty project in the Beaufort Sea area (Federal Register, Vol. 67, No. 99 pp. 36020-36022). Although some leases are actively registered in the Beaufort Sea, the time frame for development, if any is undertaken, could be beyond the time frame of this analysis.

C2-3 TOTAL NEW OIL AND GAS OPERATIONS

Table C2-12 summarizes the number of existing MODUs and platforms that are estimated to meet the proposed rule's criteria, had EPA decided to regulate existing oil and gas facilities, as well as new MODUs and platforms expected to be built over the 20-year analytical period that might be required to install control technologies. Also presented is an assessment of the number of firms involved that might be small businesses.

Table C2-12 Number of Existing and Future Offshore Oil and Gas Extraction Facilities Estimated or Assumed To Meet Proposed Rule Criteria over a 20-Year Analysis Time Frame

Type of Oil and Gas Facility	Existing Facilities				New Facilities			
	No. with >2 MGD flows	No. with >20 MGD flows	No. with >50 MGD flows	No. of Small Firms Potentially Involved[a]	No. Built in 20-Year Period >2 MGD	No. Built in 20-Year Period >20 MGD	No. Built in 20-Year Period >50 MGD	No. of Small Firms Potentially Involved[a]
MODUs	172	12	12	6	103	3	3	0
Deepwater Platforms (GOM)	8	1	0	0	20	2	0	0
20+ Slot Platforms (GOM)	4	0	0	0	0	0	0	0
Other GOM Platforms	4	0	0	0	0	0	0	0
California Platforms	7	3	0	1	0	0	0	0
Alaska Platforms	10	0	0	1	1	0	0	1
Total	205	16	12	8	124	5	3	1

[a] No small firms are involved if the cutoff is 20 MGD or greater

Source: U.S. EPA Analysis, 2004. See the 316(b) Oil and Gas Compliance Cost Model, DCN 7-4018 and ERG, 2004b.

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Chapter C3: Economic Impact Analysis for the Offshore Oil and Gas Extraction Industry

CHAPTER CONTENTS

INTRODUCTION

The Proposed Section 316(b) Rule for Phase III Facilities would potentially affect any new MODUs and oil and gas production structures that use CWISs with daily design combined intakes totaling at least 2 MGD (and at least 25% of water used for cooling water purposes). This regulatory structure is the similar to that applied to new electric generating and other industrial facilities under the Section 316(b) Phase I, Track 1 regulation.

This economic impact analysis is divided into four sections. Section C3-1 presents the analysis of the 316(b) rulemaking on MODUs, Section C3-2 presents the analysis of offshore oil and gas production platforms, Section C3-3 summarizes the costs and impacst on both MODUs and platforms and provides totals for the combined industry subgroups, and Section C3-4 presents costs to the Federal government and total social costs. The first two sections each discuss the aggregate national after-tax compliance cost estimates for new MODUs and platforms (as well as briefly summarize what these costs would be had existing MODUs and platforms been covered by the proposed rule). These sections also present vessel-level or platform-level pre- and after-tax compliance costs, and discuss impacts, both at the vessel/platform level and at the firm level. The vessel/platform level impacts are assessed using two approaches. The first approach uses the existing facilities that might represent new facilities and applies a cash-flow/net income-based analysis. The second approach is a standard barrier-to-entry analysis that investigates the present value of initial permitting costs (discounted to the assumed year of compliance) plus initial one-time capital/installation costs as a percentage of the cost to construct a new MODU or platform. The firm-level analysis uses firm revenues at firms that are the likeliest to construct new facilities. EPA applies a pre-tax and after-tax annualized cost of compliance (incorporating permitting, monitoring, capital/installation, and O&M costs) for each MODU/platform the firm is expected to build over the period of analysis. For simplicity and to be conservative, all new MODUs or platforms/structures a firm is expected to construct during this time frame are assumed to be launched or to come on line in one year for comparison to one year's revenues at the potentially affected firms. The ratio of these costs to revenues is then calculated and assessed as to whether this ratio might indicate the potential for firm-level impacts.

The methodologies used in each analysis are presented first in each section, followed by a discussion of the analytic results.

C3-1 MODU ANALYSES

C3-1.1 Aggregate National After-tax Compliance Cost Analysis

A number of costs must be considered in calculating the aggregate national after-tax compliance costs, each with distinct timing considerations. Permitting costs are incurred by facilities, but these costs are incurred by facilities to come under one of three General Permits. EPA assumes costs of studies needed to incorporate permit requirements under the General Permits can be shared. EPA further assumes that all permitting costs would be grouped into three general permit regions. These regions are Eastern Gulf of Mexico, Western Gulf of Mexico, and Alaska. Other permit activities are facility-specific and would fall on each facility affected. The timing of permitting costs is complex and was discussed in *Chapter C1: Summary of Cost Categories and Key Analysis Elements for New Offshore Oil and Gas Extraction Facilities.* More information can also be found in U.S. EPA (2004a) and ERG (2004a).

EPA assumes that four jackups and 1 semi-submersible will be built each year over the time frame of the analysis. EPA also assumes that three drill ships will be built, launched in 2012, 2017, and 2022 for a total of 103 MODUs over the 20-year period of construction. Permitting costs, therefore, apply to 80 jackups, 20 semi-submersibles and 3 drill ships. See *Chapter C2: Profile of the Offshore Oil and Gas Extraction Industry*.

Pre-tax costs of installing and operating control technologies and for various permitting activities are input to a spreadsheet in the year in which they are assumed to be incurred. Capital costs are assumed to be incurred every 10 years, and repermitting costs occur every 5 years. Each MODU is assumed to operate over a 30-year compliance period. Costs are discounted to the year of compliance, assumed to be the year the MODU is launched, and summed to produce the present value of costs in the year of compliance. These costs are then annualized over 30 years. See *Chapter C1: Summary of Cost Categories and Key Analysis Elements for New Offshore Oil and Gas Extraction Facilities* for more details on the cost discounting methodology.

To create after-tax costs, EPA assumes that the highest marginal corporate tax rate applies. This rate is 35% (IRS, 2002), so after-tax costs would be 65% of the pre-tax costs. EPA does this because all MODU owners that are likely to build MODUs are large corporations by SBA standards and all have earnings in most years that place them in the highest corporate tax bracket.

Table C3-1 summarizes the national aggregate after-tax compliance costs for MODUs. As the table shows, these costs are $1.8 million per year over the time frame of the analysis. See ERG (2004a) for a detailed description of how these costs were calculated. See also the 316(b) Oil and Gas Compliance Cost Model, DCN 7-4018 (hereinafter, Compliance Cost Model.

Had existing MODUs been covered by the proposed rule, the total national cost of the rule would have included an additional $3.6 million per year (ERG, 2004b).

Table C3-1: Total Aggregate National After-tax Compliance Costs for MODUs (2003$)

Type of Cost	Present Value (year of compliance)	Annualized Cost of Compliance
Permitting (a)	$7,111,190	$535,575
Capital/Installation		
Semi-submersibles	$597,347	$44,989
Jackups	$14,373,374	$1,082,522
Drill ships	$765,049	$57,619
Total	$15,735,770	$1,185,130
Monitoring	$1,357,609	$102,247
O&M	$0	$0
Total	$24,204,569	$1,822,952

Source: U.S. EPA Analysis, 2004. See the Compliance Cost Model, DCN 7-4018.

C3-1.2 Vessel-Level Compliance Costs

This section addresses costs to each of the three types of new vessels. Again, permitting and monitoring costs are from U.S. EPA (2004a), and capital/installation costs are from U.S. EPA (2004b). Weighted average costs reported in the TDD (U.S. EPA, 2004b) and derived for existing facilities are calculated and applied to new facilities as presented in a spreadsheet located in the rulemaking record (DCN 7-4030) and in the Compliance Cost Model, DCN 7-4018. Pre-tax costs per vessel are used in the firm-level analysis. After-tax per facility costs are also presented. After-tax costs are used for comparison to pre-tax costs and in the firm-level analysis, but are not used directly in the vessel impact analysis.[1] Additional details on how these costs are calculated are presented in ERG (2004a).

a. Pre-Tax Cost of Compliance for Representative Vessels

The costs shown in Table C3-2 reflect the costs assigned to each vessel, by type of vessel. The representative vessels are those launched in 2007 (jackups and semi-submersibles) and 2012 (drill ship) for the purposes of timing assumptions. All costs are discounted to the year of compliance, which is the same as the assumed year of launching. This date may be prior to the date actual compliance is required for some vessels. Those constructed in 2007-2012 or 2014 (depending on location) are assumed to install and operate compliance equipment immediately when they are constructed, even though permit requirements may not be in place at that time (see *Chapter C1: Summary of Cost Categories and Key Analysis Elements for New Offshore Oil and Gas Extraction Facilities* for more details). The present value costs are calculated by inputting each cost into the year that it is assumed to be incurred, which includes additional capital costs in years 11 and 21 after initial construction, repermitting costs every 5 years, and monitoring costs in the appropriate years. The costs are taken out over 30 years, discounted to the year of compliance at the recommended OMB discount rate of 7%, and then summed. The present value cost is then annualized using a 30-year time frame assumption and 7% discount rate. *Chapter C1: Summary of Cost Categories and Key Analysis Elements for New Offshore Oil and Gas Extraction Facilities* also discusses this process, as does ERG (2004a).

[1] In the impact analysis, after-tax costs are applied to existing MODUs, but these are calculated in a more exact way, since the existing MODUs have known marginal tax rates, and a depreciation schedule is used to more precisely calculate the after-tax cost impact on cash flow; see Section C3-1 below and ERG, 2004c).

Table C3-2 presents the costs of compliance on an annual basis for the three types of MODUs. As the table shows, these costs range from $14,938 to $37,638 per year depending on type of vessel. These costs are small in comparison to revenues associated with drilling even one exploration well in the deepwater GOM. The construction of these types of wells cost oil and gas production companies about $25 million to $30 million per well (U.S. EPA, 2000). The major portion of this outlay is paid to the operator of the MODU that drills the well. These costs are also small in comparison to typical MODU day rates, which can range from $150,000 to $250,000 per day (Hatton, et al., 2002).

Table C3-2: Per-Vessel Annualized Pre-Tax Cost of Compliance (2003$)

Type of Cost	Present Value (year of compliance)	Annualized Cost of Compliance
Permitting (a)		
Semi-submersibles	$128,206	$9,656
Jackups	$128,206	$9,656
Drill ships	$66,191	$4,985
Capital/Installation		
Semi-submersibles	$45,950	$3,461
Jackups	$276,411	$20,818
Drill ships	$392,333	$29,548
Monitoring		
Semi-submersibles	$24,189	$1,822
Jackups	$24,189	$1,822
Drill ships	$33,742	$2,541
O&M	$0	$0
Total		
Semi-submersibles	$198,345	$14,938
Jackups	$428,806	$32,295
Drill ships	$492,266	$37,075

Source: U.S. EPA Analysis, 2004. See the Compliance Cost Model, DCN 7-4018.

b. After-tax Costs

After-tax costs are presented here for comparison purposes. After-tax costs are assumed to be lower than the pre-tax costs by the top marginal corporate tax rate of 35%. Thus the costs calculated are 65% of the pre-tax costs in Table C3-2 above.

The annual after-tax, annualized, per-vessel compliance costs are $9,710 for semi-submersibles, $20,922 for jackups, and $24,099 for drill ships, based on the pre-tax costs shown above in Table C3-2.

C3-1.3 Impact Analysis

The impact analysis is conducted at two levels: vessel-level and firm-level. Although the financial condition of new vessels cannot be known, the financial conditions of a few, representative existing vessels are reflected in EPA's 316(b) survey of MODUs. EPA received eight economic surveys from three semi-submersibles, three jackups, and two drill ships. The financial information from these representative vessels is used for a general assessment of how well these vessels would do financially if costs of the preferred option applied. The representative vessels are thus a proxy for new sources subject to Phase III regulation. This analysis provides an alternative assessment of the potential for barrier to entry.

The second vessel-level analysis is a more typical barrier-to-entry analysis conducted by EPA for new entities, which looks at the present value of the initial permitting costs (including those associated with start-up activities, pre-permitting studies and initial permit application activities), discounted to the applicable compliance year, plus the initial one-time capital/installation costs of required control equipment and compares these costs to the baseline construction costs for each type of MODU. EPA uses an initial permit cost stream represented by MODUs expected to be constructed in 2007 (jackups and semi-submersibles) or 2012 (drill ships). See the Compliance Cost Model (DCN 7-4018).

The firm-level analysis is a revenue test, comparing the revenues of firms likely to construct MODUs with the annualized compliance costs for representative new vessels, assuming each firm identified as potentially affected builds a share of the new MODUs expected to be constructed over the time frame of the analysis. For simplicity and to be conservative, each firm is assumed to launch all their new MODUs in one year for comparison to one year's revenues. EPA uses the annualized cost stream for MODUs constructed in 2007 (or the cost stream for a drill ship constructed in 2012, the first year post-compliance in which a drill ship is assumed to be constructed) to represent the annualized costs to each potentially affected firm. EPA uses both the pre-tax and after-tax compliance costs for comparison with revenues.

a. Vessel Impact Analysis Using Survey Vessels

To calculate the impact of the today's proposal on new MODUs, EPA used two models – a cash flow/net income model, which computes the estimated present value of after tax cash flow/net income for representative MODUs (based on survey data) over a 30-year operating period for each new facility, and a post-tax cost calculation model, which estimates the present value after-tax costs of compliance using engineering and permitting cost inputs. These two models are used to analyze the effect of after-tax costs on after-tax vessel cash flow or net income. For additional details on these models, see ERG (2004c) and DCN 7-4020.

Using data provided by surveyed MODU operators, EPA used both the reported after-tax net income and a calculated cash flow figure for each survey MODU. EPA calculated cash flow using after-tax net income and adding depreciation, depletion, and amortization (DD&A) back into net income, since DD&A are not cash expenses. EPA used cash flow as an upper bound estimate of available cash and after-tax net income as a lower bound estimate. EPA was only able to undertake financial analysis for those MODUs with a positive net income or cash flow for the three years of financial information provided in the survey. EPA assumes that any MODU whose cash flow or net income is negative over the three years of financial data availability is unlikely to be a viable operation in the baseline and cannot be analyzed with respect to compliance costs.

EPA used the cash flow/net income over the three years of data collected to create a moving cycle of cash flow/net income over the period of analysis. The years of data collected were 2000, 2001, and 2002, with 2002 generally being a poorer year for the industry as a whole. In this way, EPA was able to represent industry financials in both good and bad years. The 3-year cycle provides a means for projecting the volatile oil and gas business over each facility's 30-year operating period, which is expected to include major swings in the prices of oil and gas, the driving force behind the level of operations, pricing, and thus the financial performance of newly constructed vessels. EPA assumed that cash flow/net income will be flat on average over the 30 years of analysis and thus does not apply any factors to increase or decrease cash flow or net income over the years of analysis within those cyclical movements. The cash flow/net income figures from the survey, therefore, repeat every three years for 30 years. EPA then computes the present value of that stream of cash flow/net income figures and compares it to the present value of after-tax compliance costs for the preferred option.

EPA used the capital, O&M, and permitting costs to calculate the present value of the after-tax annualized cost of compliance with the proposed requirements. Each cost is accounted for in the year in which it is assumed to be incurred. EPA made the simplifying assumption that the existing MODUs would represent new MODUs that are launched in 2007. Since EPA assumes MODUs launched in this year install and operate compliance equipment at that time (even though they do not become permitted for compliance with 316(b) requirements until the date of the first applicable General Permit renewal), EPA considers the date of launching the “compliance year.”

The first costs to be incurred are the Region 6 and Region 4 pre-permitting costs (the shared study costs) and the capital costs of installation and incremental O&M costs (O&M costs are estimated to be $0 for all MODUs). Costs for permit application activities occur in 2011 for the Region 6 permit and in 2013 for the Region 4 permit. Only MODUs are assumed to be permitted under the Region 4 permit, since relatively little production activity is currently underway in the Eastern Gulf.[2] Monitoring costs begin to be incurred in 2012. Repermitting costs enter in 2017, and every 5 years thereafter. EPA estimated capital costs for each MODU for which a financial survey response was received (with one exception), as well as many other MODUs for which financial data were not obtained (all were used to calculate the average costs of compliance for new facilities). In this analysis, however, only the costs for the eight MODUs with economic survey information were used for developing the costs for this impact analysis.

EPA’s post-tax compliance cost model determined the marginal tax rate of the owner company based on the firm’s average taxable earnings over the three years of survey data (which were put on a mid-year 2003 basis to match the engineering costs, which were also set to 2003 dollars) and used the modified accelerated cost recovery system (MACRS) to calculate depreciation on the capital outlay. Depreciation was then used to compute a “tax shield” on the investment (for more information on EPA’s post-tax cost calculation model, see ERG [2004c] and DCN 7-4020). The post-tax cost calculation model calculates the present value of after-tax compliance costs.

The present value output from the post-tax cost calculation model is then input to the cash flow/net income model and used to compare with the present value of cash flow/net income of the vessel as discussed above. If the present value of baseline after-tax cash flow or net income minus the present value of after-tax compliance costs is greater than $0, EPA assumes that the MODU would be able to continue to operate post-compliance. If the cash flow value becomes negative, EPA assumes the MODU would no longer continue to operate. If the net income value becomes negative, EPA assumes the longer term viability of the vessel is potentially jeopardized. In either case, such a MODU would be counted as a potential “regulatory closure.” This analysis is considered an alternative assessment of the potential for barrier to entry.

Although many of EPA’s analyses investigate whether costs of compliance can be passed through to customers, this analysis makes an assumption that costs cannot be passed through. Because existing MODUs would not have to meet the requirements of the proposal, and new MODUs must compete with these existing MODUs, it is unlikely that new MODUs would be able to pass through any compliance costs. Assuming zero cost pass-through provides a realistic estimate of potential economic impacts to new MODUs.

Due to confidential business information (CBI) constraints, EPA is not able to provide detailed impact results on a MODU-specific level. Detailed results are provided in the CBI portion of the Rulemaking Record (ERG, 2004c, CBI version, and DCN 7-4020). The general findings of the closure analysis are that no new MODUs would be regulatory closures, based on an assumption that finances for new MODUs might look like those for existing MODUs, as a result of the incremental costs of compliance with the preferred option using either a cash flow or net income approach.

b. Barrier to Entry Analysis (Vessel-Level)

[2] Permitting costs to platforms are assumed to be associated with the Western Gulf Permit; use of this assumption avoids potentially understating the magnitude of shared costs to MODUs in Region 4.

EPA used the incremental capital/installation costs and the net present value of permitting costs of compliance for MODUs, as discussed above, using the cost streams associated with vessels launched in 2007 (jackups and semi-submersibles) and 2012 (drill ships), discounted to the compliance year. The sum of these costs (capital and permitting) were then compared to the costs of constructing new MODUs. If these compliance costs comprised a small fraction of construction costs, EPA assumed that compliance costs would not have a major impact on future MODUs and would not have an effect on a decision to build additional MODUs.

EPA estimated the incremental capital costs to install CWISs that meet the requirements of 316(b) Phase I, Track 1. These costs are $26,008 for semi-submersibles, $156,450 for jackups, and $222,062 for drill ships. The present value of a share of the permit costs is $101,192 for each vessel except those for drill ships, which are $24,521 (because they are assumed not be involved in the initial study cost sharing due to their much later assumed launch dates). The total incremental initial investment costs, therefore, are $127,200 for semi-submersibles, $257,642 for jackups, and $246,583 for drill ships). According to Drilling Contractor Magazine (2003), the cost of new MODUs planned to be built in the next few years average $250 million for semi-submersibles and $125 million for jackups. A drill ship completed in 1998 (R&B Falcon's Pathfinder[3]) cost approximately $275 million. Incremental present value of permitting costs plus capital/installation costs are therefore estimated to range from 0.05% to 0.21% of construction costs, regardless of type of MODU. Because this is only a tiny fraction of total costs of construction (and a tiny fraction of contingency, which typically ranges from 10% to 20% of capital/installation costs), EPA believes that these costs would not have a material effect on decisions to build new MODUs.

c. Firm-Level Analysis

To determine the impact of the proposed rule on firms, EPA uses a revenue test, which compares the annualized pre-tax and after-tax costs of compliance (calculated as discussed for each representative MODU as discussed above), with 2002 revenues reported by all firms determined likely to build new MODUs meeting the proposed rule's criteria. Because nearly all of these firms (other than foreign-owned) are publicly owned, EPA relied on the revenue data reported in *Chapter C2: Profile of the Offshore Oil and Gas Extraction Industry*, which was compiled from corporate 10K reports downloaded from SEC's Edgar Database. EPA determined the number of MODUs likely to be built by each firm under the proposed rule. Only those firms that were identified as currently owning jackups, semi-submersibles, and drill ships that would meet the proposed rule's criteria if newly constructed are considered likely to construct the estimated 103 new MODUs that would be affected by the proposal. These same firms also generally comprise the firms that are currently building new MODUs (see also *Chapter C2: Profile of the Offshore Oil and Gas Extraction Industry*). EPA then assigned a number of potentially in-scope MODUs to be built by each of the firms and used the average per-MODU compliance costs multiplied by the number of these potentially in-scope MODUs to calculate the total compliance costs that might be faced by these firms.

To calculate costs to revenues, EPA uses the pre-tax and after-tax costs shown in Table C3-2 for the firms identified as likely to construct new MODUs meeting the proposed rule's criteria. Each firm is assumed to build 12 jackups or semi-submersibles over the time frame of the analysis (a little over one every other year), except for GlobalSantaFe and Transocean, which are assumed to build 20 jackups and one drill ship or two drillships, respectively. For simplicity and to be conservative, EPA assumes that all MODUs estimated to be constructed by these firms are launched in one year for comparison with one year's revenues at those firms. EPA uses the higher cost of a jackup rig to represent the cost of compliance for both jackups and semi-submersibles for simplicity.

Table C3-3 shows all of the MODU owners that are considered likely to build an in-scope MODU. As the table shows, annualized pre-tax costs per firm range from $0.4 to $0.7 million. The ratio of pre-tax costs to revenues ranges from 0.03% to 0.06% and after-tax costs to revenue range from 0.02% to 0.04%. Given that the highest ratio seen is 0.06 percent, EPA concludes that firm-level impacts would be minimal. Furthermore, even if these costs applied to other firms (among those that own jackups or semi-submersibles with unknown CWIS intake

[3] R&B Falcon was acquired by Transocean, Inc. (see *Chapter C2: Profile of the Offshore Oil and Gas Extraction Industry*).

rates that are considered unlikely to build new MODUs subject to Phase III regulation), impacts on any firm would still be estimated to be much less than 1 percent.[4]

These costs reflect the assumption that all new jackups would be built with sea chests and, therefore, these vessels would not be required to meet entrainment controls. However, jackups on rare occasions use straight pipes. If jackups are not built with sea chests, the costs to comply with both impingement and entrainment contros would result in the annualized per-vessel compliance costs to rise from $32,295 to $39,063. Under this scenario, the costs to revenue ratios shown in Table C3-3 would be at most 0.08 percent (see DCN 7-4030 and DCN 7-4018).

Table C3-3: Revenue Test for MODU Owners

Name	No. of Likely In-scope Rigs >2 MGD Built in One Year	Revenues ($millions)	Annualized Pre-Tax Costs per Firm ($millions)	Costs to Revenues (%)	Annual-ized After-tax Costs per Firm ($millions)	Costs to Revenues (%)
Diamond Offshore	12	$753	$0.4	0.05%	$0.3	0.03%
ENSCO	12	$698	$0.4	0.06%	$0.3	0.04%
GlobalSantaFe	21	$2,018	$0.7	0.03%	$0.4	0.02%
Noble	12	$986	$0.4	0.04%	$0.3	0.03%
Pride	12	$1,270	$0.4	0.03%	$0.3	0.02%
Rowan	12	$617	$0.4	0.06%	$0.3	0.04%
Transocean	22	$2,674	$0.7	0.03%	$0.5	0.02%
Total/Avg.	103	$9,406	$3.3	0.04%	$2.2	0.02%

Source: SEC, 2003; U.S. EPA Analysis, 2004. See Compliance Cost Model, DCN 7-4018.

C3-2 Economic Impact Analysis for Oil and Gas Production Platforms

This section presents the aggregate national after-tax compliance costs for new oil and gas production platforms that will be built in scope. It also presents platform-level compliance costs (in after-tax and pre-tax terms). Impacts on platforms are then presented in two sections. The first section uses a model of a new platform to determine the potential for any effect on production. The second section uses an approach for identifying barriers to entry for all platforms likely to be built in scope and for assessing impacts on those platforms for which information was not sufficient to create a detailed economic model. As discussed in *Chapter C2: Profile of the Offshore Oil and Gas Extraction Industry*, only 20 in-scope deepwater platforms and one in-scope Alaska platform are expected to be constructed over the 20 year construction time frame of the analysis under the proposed rule.

[4] There are several firms owning jackups or semi-submersibles that did not submit voluntary technical data, so EPA is not able to determine whether they own MODUs that might meet the proposed rule's criteria were they to be newly constructed. These firms are Atwood Oceanics, Caspian Drilling Co., Energy Equipment Resources, Nabors Industries, Newfield Exploration, Ocean Rig ASA, Parker Drilling, Tetra Technologies, and Workships BV. Most of these firms, however, own only one or two such MODUs and are considered far more likely to purchase MODUs from the firms included in this analysis than to build their own (several of these MODUs have clearly been purchased from GlobalSantaFe, for example). Had these firms been included in the analysis, however, EPA's findings would not have changed. The firm with the lowest revenues in this group among those with publicly available data (Atwood Oceanics, Parker Drilling, and Newfield Exploration; see *Chapter C2: Profile of the Offshore Oil and Gas Extraction Industry*) reported 2002 revenues as $149 million. Applying the same methodology that EPA used for the firms considered likely to build MODUs, EPA would predict that the cost-to-revenue ratio among these firms considered unlikely to build MODUs would be at most 0.3 percent.

C3-2.1 Aggregate National After-tax Compliance Costs

The methodology for calculating the aggregate national after-tax compliance costs are identical to that used for calculating these same costs for MODUs, although the costs incurred are different. Costs are input in each year in which they occur over the 30-year time frame of the analysis, including recurring capital replacement costs, repermitting costs, and O&M. The costs in each year are discounted to the compliance year (assumed the year the platform comes on line) and summed to calculate the present value of the cost stream. These present value costs are then annualized. For more details on timing assumptions and annualized and present value cost calculations, see *Chapter C1: Summary of Cost Categories and Key Analysis Elements for New Offshore Oil and Gas Extraction Facilities* and ERG (2004a).

To create after-tax costs, EPA assumes that the highest marginal corporate tax rate applies. This rate is 35 percent (IRS, 2004), so after-tax costs will be 65 percent of the pre-tax costs. EPA does this because all platform owners that are likely to build in-scope platforms are large corporations by SBA standards and/or have earnings that place them in the highest corporate tax bracket (including the one small corporation considered likely to build an Alaska platform).

Table C3-4 summarizes the national aggregate after-tax compliance costs for production platforms. As the table shows, these costs are $1.2 million per year over the time frame of the analysis. See ERG (2004a) for a detailed description of how these costs were calculated. Also see DCN 7-4018.

Had existing platforms been covered by the proposed rule, the total national cost of the rule would have included an additional $4.5 million per year (ERG, 2004b).

Table C3-4: Total National Aggregate After-tax Compliance Costs for Platforms (2003$)

Type of Cost	Present Value (to year of compliance)	Annualized Cost of Compliance
Permitting (a)		
Deepwater	$842,324	$63,439
Alaska	$481,371	$36,254
Total	$1,323,695	$99,693
Capital/Installation		
Deepwater	$5,227,966	$393,741
Alaska	$390,008	$29,373
Total	$5,617,974	$423,114
Monitoring		
Deepwater	$187,012	$14,085
Alaska	$190,138	$14,320
Total	$377,150	$28,405
O&M		
Deepwater	$7,703,465	$580,182
Alaska	$1,371,845	$103,320
Total	$9,075,310	$683,502
Total Compliance Costs		
Deepwater	$13,960,768	$1,051,447
Alaska	$2,433,362	$183,267
Total National Compliance Costs	$16,394,129	$1,234,714

Source: U.S. EPA Analysis, 2004. See the Compliance Cost Model, DCN 7-4018.

C3-2.2 Platform-Level Compliance Costs

This section addresses costs to each of the two types of platforms (deepwater and Alaska). Again, permitting and monitoring costs are from U.S. EPA (2004a), and capital/installation and O&M costs are from U.S. EPA (2004b), with the weighted average of the capital and O&M costs applied to new platforms/structures as calculated in DCN 7-4030. Pre-tax costs per platform are used in the firm-level analysis, along with after-tax costs. After-tax costs are used for comparison to pre-tax costs but are not used directly in the platform impact analysis.[5] See ERG (2004a) for more detail on how these costs were calculated. Also see DCN 7-4018.

[5] In the impact analysis, costs are input in the year in which they are assumed to be incurred, and the financial model internally calculates the tax shield on these costs given depreciation schedules; see Section C3-2.3a below and ERG [2004d]).

a. Pre-Tax Cost of Compliance for Representative Platforms

The costs shown in Table C3-5 reflect the estimated costs incurred by each platform, by type of platform. Costs are derived as above for computing national aggregate costs, but these costs are for a representative deepwater platform that comes on line in 2007 (year of compliance assumed 2007) and the representative Cook Inlet platform coming on line in 2014 (year of compliance). Costs (which are incurred over the full time frame of the analysis, including recurring capital replacement and repermitting costs) are discounted to the applicable year of compliance and annualized over 30 years at 7 percent.

Table C3-5 presents the costs of compliance on an annual basis for the two types of platforms. As the table shows, these costs are $82,338 or $281,949 depending on type of platform.

Table C3-5: Per-Platform Annualized Pre-Tax Cost of Compliance (2003$)

Type of Cost	Present Value (Year of Compliance)	Annualized Cost of Compliance
Permitting share		
Deepwater	$80,513	$6,064
Alaska	$740,570	$55,776
Capital/Installation		
Deepwater	$402,151	$30,288
Alaska	$600,012	$45,190
Monitoring share		
Deepwater	$18,021	$1,357
Alaska	$292,520	$22,031
O&M		
Deepwater	$592,574	$44,629
Alaska	$2,110,532	$158,953
Total		
Deepwater	$1,093,259	$82,338
Alaska	$3,743,633	$281,949

Source: U.S. EPA Analysis, 2004. See the Compliance Cost Model, DCN 7-4018.

b. After-tax Costs for Representative Platforms

After-tax costs are presented here for comparison purposes. After-tax costs are assumed to be lower than the pre-tax costs by the top marginal corporate tax rate of 35 percent (IRS, 2002). Thus the costs calculated are 65 percent of the pre tax costs in Table C3-5 above.

The annual after-tax per-platform compliance costs are $53,520 for deepwater platforms and $183,267 for the Alaska platform, based on the pre-tax costs shown above in Table C3-5.

C3-2.3 Impact Analysis

The impact analysis for oil and gas production platforms is divided into two types: platform-level and firm-level. The platform-level analyses include two approaches to determining the potential for impacts. Although the financial condition of new platforms cannot be known, the financial conditions of a few, representative existing platforms are reflected in EPA's 316(b) survey of production platforms. EPA received economic surveys from one deepwater platform and one Alaska platform with CWIS intake rates meeting the proposed rule's requirements. The financial information from the deepwater platform is used for a general assessment of how well new deepwater platforms would do financially if the proposed rule's costs applied. The Alaska platform that was surveyed, however, is a very old structure and is at the end of its productive life, thus has a production profile completely different from what would be expected of a new operation. Furthermore, new platforms constructed in Cook Inlet are far likelier to look like the Osprey platform, which is a departure from the older technology represented by the other Cook Inlet platforms. The Osprey platform was designed to operate as a MODU until a productive reservoir was located, at which point the MODU was designed to convert to a stationary production platform. This design allowed Osprey to be built at a significantly lower cost than the traditional fixed platforms located in the inlet. EPA does not have sufficient financial information at this time to model an Osprey-type platform. For these reasons, the potential for impact on a new Alaska platform is assessed only in the second platform-level analysis, described below.

The second platform-level analysis is a more typical barrier-to-entry analysis used for new entities. It uses the present value of initial permitting costs (discounted to the year of compliance) plus the capital/installation costs and compares these costs to the construction costs for each type of platform. This is a typical barrier-to-entry analysis, which assesses incremental start-up costs associated with compliance to baseline start-up costs.

The firm-level analysis is a revenue test, comparing the revenues of firms likely to construct platforms whose CWISs meet the proposed rule's criteria with the annualized compliance costs for each platform, assuming each firm considered likely to build a regulated platform in the deepwater builds four platforms/structures over the time frame of the analysis. For simplicity and to be conservative, EPA assumes the firms bring all platforms on line in one year for comparison to one year's revenues. One small firm is assumed the likeliest to build one platform in Alaska during the time frame of the analysis, and this firm is assigned the cost of the one Alaska platform assumed to be constructed during the analysis period.

a. Platform Impact Analysis Using Survey Platforms

Oil and gas production platforms are modeled somewhat differently than most other Phase III entities. Because the surveyed deepwater platform was a relatively new structure in 2002 (the first year of survey data provided), the model is built using survey data to represent new, later-built structures.

Generally, the model can show production extending as far out as 30 years. Calculations, such as the after-tax costs of compliance that are computed outside of the model platform framework (presented earlier in this Chapter), use a 5 or 10-year time frame over which to annualize costs. The platform model operates somewhat differently. Pre-tax costs are input into the model in the year in which they occur (including costs incurred in pre-production years). The model calculates after-tax costs, which are then annualized over the modeled production life, which could be shorter than 30 years. For this reason, repermitting costs are input into the model every five years and capital costs for CWISs are input every 10 years, until the model shows the platform is uneconomical to operate.

EPA has developed a model deepwater oil and gas production platform based on information obtained from EPA's survey and from other sources of publicly available information, such as that from MMS. ERG (2004d; non-CBI version) contains additional details on the methodology, non-CBI data, and assumptions on which the model is based and how the model was constructed. EPA has used the same basic approach a number of times for analyzing impacts of effluent guidelines on oil and gas facilities (see, for example, U.S. EPA, 2000). Usually, the only differences are the input variables, such as production rates, that are used to model individual platforms. For specific details on the values of variables defined by survey information and the detailed impact results, see ERG (2004d; CBI version).

The model is based on both a cash flow and net income approach. The projected net revenues are compared to operating costs at each year for each model project. Net revenues (after subtracting royalties and severance, which are payments to the lease owner and a State, if relevant) are based on an assumed price of oil, current and projected production of oil and gas, well production decline rates, and severance and royalty rates. Operating costs are based on a calculated cost per barrel of oil equivalent (BOE) produced. The model runs for 30 years or is assumed to shut in when operating costs exceed revenues. That is, the economic model can calculate differing lifetimes according to project characteristics. The model then calculates the lifetime of the project, total production and the net present value of the operation (net income of the operation over the life of the project in terms of today's dollars), which includes the net operating earnings, taxes, expenditures on drilling, other capital expenditures, etc. A positive net present value means that the project is a good investment. In this case the return is greater than the discount rate, which represents the opportunity cost of capital. If the net present value is negative, it means that money would have been better invested elsewhere.

The model is run twice–with and without the change due to the 316(b) Phase III requirements. The incremental cost to retrofit I&E equipment is input into a capital expenditure line (which is used in both the cash flow and net income calculations), and additional O&M and permitting costs are input to the cash flow section of the model. The post-compliance results (including production, project life, and net present value of income) are compared to those calculated under baseline assumptions.

There are two ways the increased costs can have an impact on a platform. First, any increase in operating costs might raise total operating costs enough to cause the operating costs to exceed net revenues earlier than in the baseline. If the platform life is reduced, there will be a concomitant loss of production. Second, any increase in costs, whether operating, capital or permitting, could also drive the net present value of a marginal operation negative. The decision in this case would be to not develop the project rather than build the project with I&E controls in place, since the project would not be considered a good investment. If the platform has a positive net present value under baseline conditions but a negative net present value in the post-compliance scenario, EPA notes an impact on the platform and estimates the production lost as a result.

Due to issues with CBI, the detailed results of the platform-specific impacts are not reported here. See ERG (2004d; CBI version) in the CBI portion of the Rulemaking Record for detailed information on impacts. However, EPA determined that there would be no impacts on deepwater oil and gas development or production due to the proposed rule's costs based on model results. Impacts on net present value of projects is expected to be very small.

b. Barrier to Entry Analysis (Platform Level)

EPA uses the incremental capital costs and present value of initial permitting costs for compliance for new deepwater and Alaska platforms to compare to the costs of construction of new platforms, identical to the approach used to measure impacts on MODU owners. If the initial investment costs of compliance are a small fraction of baseline construction costs, EPA assumes that compliance costs would not have a major impact on future platforms and would not have an effect on a decision to build additional oil and gas production platforms.

Costs for constructing deepwater platforms are estimated to range from $114 million to $2.3 billion (see U.S. EPA, 2000). Forest Oil (Forest Oil, 2004) reports that the 2002 capital outlay for the Osprey platform in Cook Inlet was $120 million (which does not include exploration, delineation, or additional costs to continue to develop the platform). For deepwater platforms, EPA estimates that a platform coming on line in 2007 would incur costs of $291,253 (deepwater) and $685,161 (Alaska) in capital/installation costs plus the present value cost of the initial round of permitting costs. The ratio of incremental compliance costs to construction costs ranges from 0.01 percent to 0.3 percent for deepwater projects and 0.6 percent for an Alaska project. This is a small fraction of contingency on these projects.

c. Firm Level Impacts

The firms that are considered affected are those identified as currently having platforms or structures in the deepwater that meet the proposed rule's criteria. In Alaska, Forest Oil is selected as the likeliest type of firm to build an Alaska platform during the time frame of the analysis. All the firms considered likely to build a new platform/structure subject to the proposed rule have publicly available data on 2002 revenues. Each firm is expected to bring on line four affected platforms over the period of analysis. For simplicity and to be conservative, EPA assumes all four platforms are brought on line in the same year for comparison to one year's revenues. The costs of compliance are calculated as the cost stream over the compliance lifetime of a representative deepwater platform constructed in 2007 and an Alaska platform constructed in 2014, discounted to the year of compliance and annualized (the same approach used for judging impacts on MODU owners). These costs are then compared to firm-level revenues in a revenue test. Both pre-tax costs, reported in Table C3-5 above, and after-tax costs are used to compare to revenues.

Table C3-6 presents the affected firms in both regions of concern (deepwater and Alaska), their annual revenues, their annualized pre-tax costs of compliance applied to all potentially affected structures they might construct, and the ratio of their compliance costs to revenues. As the table shows, costs to revenues are 0.012 percent or less for all affected firms.

Table C3-6: Revenue Test for Platform Owners

Name	No. of Platforms	Revenues ($millions)	Pre-Tax PV Costs ($millions)	Pre-Tax Costs to Revenues	After-tax Initial Investment Costs	After-tax Costs to Revenues
Amerada Hess	4	$3,783	$0.3	0.009%	$0.2	0.006%
BP	4	$178,721	$0.3	<0.001%	$0.2	<0.001%
ChevronTexaco	4	$56,748	$0.3	0.001%	$0.2	<0.001%
ExxonMobil	4	$205,000	$0.3	<0.001%	$0.2	<0.001%
Forest Oil	1	$2,450	$0.3	0.012%	$0.2	0.007%
Royal Dutch/Shell	4	$235,598	$0.3	<0.001%	$0.2	<0.001%
Total	21	$682,300	$1.90	<0.001%	$1.3	<0.001%

Source: SEC, 2003; U.S. EPA Analysis, 2004. See the Compliance Cost Model, DCN 7-4018.

C3-3 TOTAL COSTS AND IMPACTS AMONG ALL AFFECTED OIL AND GAS INDUSTRY ENTITIES

Table C3-7 on the following page summarizes the total costs and impacts associated with the 316(b) Phase III Rulemaking on the oil and gas industry.

As the table shows, impacts on new MODUs and platforms and their associated firms are expected to be minimal, Aggregate national after-tax compliance costs are also shown in the table. These costs total $1.8 million per year for MODUs and $1.2 million per year for platforms, which is $3.1 million per year over all affected new oil and gas operations estimated to be constructed over the period of the analysis.

Table C3-7: Total National Aggregate Annualized After-tax Compliance Costs and Impacts for the Oil and Gas Industry (2003$)

O&G Facility	Annualized After-tax Compliance Costs (in $millions, discounted to year of compliance)	Facility Impacts	Firm Impacts
MODUs	$1.8	0	0
Platforms	$1.2	0	0
Total[a]	$3.1	0	0

[a] Totals may not sum due to independent rounding.

Source: U.S. EPA Analysis, 2004. See the Compliance Cost Model, DCN 7-4018.

C3-4 Total Costs to Government Entities and Social Costs of the 316(b) Phase III Rulemaking

C3-4.1 Total Costs to Government Entities

The costs in Table C3-8 reflect those costs to Region 6, Region 4 and Region 10 to administer the costs of the three General Permits as well as to maintain these permits over time as the number of permittees increases or decreases. The details of individual cost items and timing assumptions can be seen in *Chapter D2: UMRA Analysis.* Costs are arrayed over the time frame of the analysis and discounted at either 3% or 7% to 2007.

Table C3-8: Total Costs to Government Entities (2003$)

Government Entity	Present Value Cost (2007)	Annualized Cost
3% Discount Rate		
EPA Region 6	$4,670,139	$231,327
EPA Region 4	$3,792,250	$187,843
EPA Region 10	$40,778	$2,020
Total government cost	$8,503,168	$421,190
7% Discount Rate		
EPA Region 6	$2,394,817	$180,364
EPA Region 4	$1,888,682	$142,245
EPA Region 10	$22,602	$1,702
Total government cost	$4,306,101	$324,311

Source: U.S. EPA 2004a; U.S. EPA Analysis, 2004. See the Compliance Cost Model, DCN 7-4018.

C3-4.2 Total Social Costs

The total costs to government entities, plus the total pre-tax cost to industry are used as an approximation of total social cost. There is no lost production of oil and gas calculated and no closures or firm failures are estimated. Thus no social costs associated with employment dislocations are incurred. A small deadweight loss would occur, but this is not calculated. Consumer and producer surplus losses are also not calculated, but they are captured in the total pre-tax cost to industry.

Table C3-9 presents the total social costs associated with the 316(b) requirements under the proposed rule. The annualized social costs of the rule associated with the affected oil and gas industries under the proposed rule is approximately $3.7 million using the 3 percent social discount rate suggested by OMB and $3.0 million per year using OMB's 7 percent discount rate.

Table C3-9: Total Social Costs of the Proposed Rulemaking for Oil and Gas Industries (in millions, 2003$)

Cost Item	Present Value Cost (2007)	Annualized Costs
3 % Discount Rate		
MODU compliance costs	$37.5	$1.9
Platform compliance costs	$28.0	$1.4
Total pre-tax compliance costs	$65.4	$3.2
Government cost	$8.5	$0.4
Total social costs	$73.9	$3.7
7 % Discount Rate		
MODU compliance costs	$21.4	$1.6
Platform compliance costs	$14.6	$1.1
Total pre-tax compliance costs	$36.0	$2.7
Government costs	$4.3	$0.3
Total social costs	$40.3	$3.0

Note: Totals may not add due to independent rounding.

Source: EPA Analysis, 2004. See the Compliance Cost Model, DCN 7-4018.

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Chapter D1: Regulatory Flexibility Analysis

INTRODUCTION

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

CHAPTER CONTENTS

Small entities include small businesses, small organizations, and small governmental jurisdictions. For assessing the impacts of the proposed regulation proposal on small entities, a small entity is defined as: (1) a small business as defined by the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

The SBA small business size standards changed from a SIC code-based system to a NAICS code-based system on October 1, 2000. Since EPA conducted its data collection effort for existing facilities before this change, EPA performed the small entity analysis for existing facilities based on SIC codes. EPA then conducted a subsequent analysis to determine whether use of NAICS codes-based size standards would yield different results. This analysis showed, for the three proposed options as well as for all other evaluated options, that the small entity determinations and assessments of small entity impacts are the same under both SIC-based and NAICS-based size standards. Appendix 2 to this chapter presents the findings for the comparison of the SIC-based analysis and the NAICS-based analysis.

To evaluate the potential impact of this rule on small entities, EPA identified the domestic parent entity of each facility potentially subject to Phase III regulation, and determined its size. EPA then used a "sales test" to assess the potential severity of economic impact on small entities. The test compares annualized compliance cost to total entity sales revenues. This analysis uses three cost-to-revenue ranges to report the estimated number and percentage of small entities incurring compliance costs: less than 1%; at least 1% but less than 3%; and at least 3%. EPA assumed that small entities with costs of 3% of revenues or more might be significantly impacted as a result of the proposed rule.

EPA is proposing three options that define which existing facilities would be subject to the national categorical requirements under the proposed rule: the "50 MGD for All Waterbodies" option (the "50 MGD All" option); the "200 MGD for All Waterbodies" option (the "200 MGD All" option); and the "100 MGD for Certain Waterbodies" option (the "100 MGD CWB" option). These options all require the same reduction in impingement and entrainment (I&E), and differ only by design intake flow (DIF) applicability threshold and waterbody type. As a result, the number of facilities that would be required to meet the national categorical requirements varies among the three options: the 50 MGD All option, the proposed option with the broadest applicability, would apply national categorical requirements to 136 facilities. The 200 MGD All option would apply national categorical requirements to 25 facilities, while the 100 MGD CWB option would apply national categorical requirements to 19 facilities. In addition to the analyses for the three proposed options, the appendix to this chapter presents analyses for five other options evaluated but not proposed for existing facilities (Option 1, Option 2, Option 3, Option 4, and Option 6).

EPA is also proposing section 316(b) requirements for new offshore oil and gas extraction facilities (also abbreviated as "new OOGE facilities") in Phase III. These proposed requirements are based on a 2 MGD DIF applicability threshold and would apply to an estimated 124 new offshore oil and gas extraction facilities.

EPA's analysis found that this proposed rule would not have a significant economic impact on a substantial number of small entities. This determination is based on the finding that this rule would apply national categorical requirements to only one small entity (entities that operate facilities subject to permit specifications based on best professional judgment, BPJ, would not incur incremental compliance costs under this rule and are excluded from this analysis). In the Manufacturers and Electric Generators industry segments, no small entity is expected to meet the lowest proposed flow threshold of 50 MGD and therefore, no small entity in these segments would be subject to the national requirements. In the new offshore oil and gas extraction industry segment, EPA estimates that the proposed rule would apply national requirements to only one small entity. EPA estimates that this entity would incur annualized after-tax compliance costs of less than 0.1% of annual sales revenues.

D1-1 ANALYSIS OF MANUFACTURERS

EPA's 2000 Section 316(b) *Detailed Industry Questionnaire* (U.S. EPA, 2000) identified 199 facilities in the five Primary Manufacturing Industries – Paper, Chemicals, Petroleum, Aluminum, and Steel – assessed as potentially subject to the options considered for Phase III existing facilities. As described in *Chapter B3: Economic Impact Analysis for Manufacturers*, these 199 facilities represent 532 facilities in those industries.[1] In addition, this section also considers the effect of the regulation on facilities in Other Industries that are also expected to be affected by the regulation. The analysis of facilities in Other Industries is restricted to a sample of 22 facilities for which EPA received surveys but which are not part of the statistically valid sample. EPA estimates that 30 of the 199 sampled facilities in the five Primary Manufacturing Industries, representing 76 facilities industry-wide, and four of the 22 known facilities in Other Industries are baseline closures; these facilities are excluded from this analysis (see *Chapter B3: Economic Impact Analysis for Manufacturers* for more information). The remainder of the small entity analysis for Manufacturers therefore discusses research done for the 169 sample facilities in Primary Manufacturing Industries, representing 456 facilities that are open in the baseline, and an additional 18 known facilities in Other Industries that are open in the baseline.

Although EPA's sample-based data for the Primary Manufacturing Industries support specific estimates of the number of small entity-owned facilities, these data do not support a specific estimate of the number of small entities that own these facilities. As a result, EPA estimated the number of small entities owning facilities in the Primary Manufacturing Industries as a range, based on alternative assumptions about the ownership of regulated manufacturing facilities by small entities.

D1-1.1 Small Entity Determination

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

- Identify the domestic parent entity of the 169 sample facilities in the Primary Manufacturing Industries and the 18 additional known facilities in Other Industries.

- Determine the size of the entities owning the 169 sample facilities in the Primary Manufacturing Industries and the 18 additional known facilities in Other Industries.

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[1] EPA applied sample weights to the 199 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).

a. Identification of Domestic Parent Entities

The RFA analysis is conducted at the highest level of domestic ownership, referred to as the "domestic parent entity" or "domestic parent firm." EPA gathered information on the domestic parent firm in the *Detailed Industry Questionnaire*. In instances where a response was not provided, EPA used several other data sources to determine the domestic parent firm including the *Screener Questionnaire*, corporate websites, and Dun & Bradstreet data (D&B, 2003). EPA determined that 100 unique entities own the 169 facilities in the Primary Manufacturing Industries. One known facility in the Other Industries was also found to be owned by a firm that owns facilities in the Primary Manufacturing Industries. Therefore, the 100 unique entities own 170 sample facilities. The remaining 17 facilities in Other Industries were found to be owned by 14 unique entities.

b. Size Determination of Domestic Parent Entities

EPA identified the size of each entity owning a potentially regulated Manufacturers facility using Small Business Administration (SBA) size threshold guidelines.[2] These thresholds define the minimum firm-level employment or revenue size, by industry (four-digit SIC codes), below which a business qualifies as a small business under SBA guidelines.[3] To determine the entity size, EPA used data from the *Detailed Industry Questionnaire*, as well as the *Screener Questionnaire*, corporate websites, the U.S. Securities and Exchange Commision's (SEC) *FreeEdgar* database, corporate websites, and Dun & Bradstreet data (SEC, 2004; D&B, 2003).

Table D1-1 presents the unique firm-level 4-digit SIC codes and corresponding SBA size standards used to determine the size of entities that own Manufacturers facilities potentially subject to Phase III regulation.

Table D1-1: Unique 4-Digit Firm-Level SIC Codes and SBA Size Standards for Manufacturers [a]

SIC Code	SIC Description	SBA Size Standard
0133	Sugarcane and Sugar Beets	$0.5 Million
1011	Iron Ores	500 Employees
1311	Crude Petroleum and Natural Gas	500 Employees
2011	Meat Packing Plants	500 Employees
2046	Wet Corn Milling	750 Employees
2061	Cane Sugar, Except Refining	500 Employees
2062	Cane Sugar Refining	750 Employees
2063	Beet Sugar	750 Employees
2075	Soybean Oil Mills	500 Employees
2211	Broadwoven Fabric Mills, Cotton	1,000 Employees
2421	Sawmills and Planing Mills, General	500 Employees
2611	Pulp Mills	750 Employees
2621	Paper Mills	750 Employees
2631	Paperboard Mills	750 Employees
2653	Corrugated and Solid Fiber Boxes	500 Employees
2673	Plastics, Foil, and Coated Paper Bags	500 Employees

[2] The SBA website provides the most recent size thresholds at http://www.sba.gov/regulations/siccodes.

[3] For a comparison of the small entity determination using SIC codes and NAICS codes, respectively, see Appendix 2 to this chapter.

Table D1-1: Unique 4-Digit Firm-Level SIC Codes and SBA Size Standards for Manufacturers [a]

SIC Code	SIC Description	SBA Size Standard
2679	Converted Paper and Paperboard Products, NEC	500 Employees
2711	Newspapers: Publishing, or Publishing and Printing	500 Employees
2812	Alkalies and Chlorine	1,000 Employees
2813	Industrial Gases	1,000 Employees
2819	Industrial Inorganic Chemicals, NEC	1,000 Employees
2821	Plastics Material and Synthetic Resins, and Nonvulcanizable Elastomers	750 Employees
2824	Manmade Organic Fibers, Except Cellulosic	1,000 Employees
2833	Medicinal Chemicals and Botanical Products	750 Employees
2834	Pharmaceutical Preparations	750 Employees
2851	Paints, Varnishes, Lacquers, Enamels, and Allied Products	500 Employees
2869	Industrial Organic Chemicals, NEC	1,000 Employees
2873	Nitrogenous Fertilizers	1,000 Employees
2874	Phosphatic Fertilizers	500 Employees
2891	Adhesives and Sealants	500 Employees
2899	Chemicals and Chemical Preparations, NEC	500 Employees
2911	Petroleum Refining	1,500 Employees
3312	Steel Works, Blast Furnaces (Including Coke Ovens), and Rolling Mills	1,000 Employees
3313	Electrometallurgical Products, Except Steel	750 Employees
3315	Steel Wiredrawing and Steel Nails and Spikes	1,000 Employees
3316	Cold-Rolled Steel Sheet, Strip, and Bars	1,000 Employees
3317	Steel Pipe and Tubes	1,000 Employees
3334	Primary Production of Aluminum	1,000 Employees
3353	Aluminum Sheet, Plate, and Foil	750 Employees
3421	Cutlery	500 Employees
3714	Motor Vehicle Parts and Accessories	750 Employees
3728	Aircraft Parts and Auxiliary Equipment, NEC	1,000 Employees
3999	Manufacturing Industries, NEC	500 Employees
5153	Grain and Field Beans	100 Employees
5171	Petroleum Bulk Stations and Terminals	100 Employees
6141	Personal Credit Institutions	$5.0 Million
6719	Offices of Holding Companies, NEC	$5.0 Million

Source: U.S. SBA, 2000.

As discussed earlier, EPA estimated the number of small entities owning facilities in the manufacturing industries as a range, based on alternative assumptions about the possible ownership of potentially regulated manufacturing facilities by small entities. EPA considered two cases based on the sample weights developed from the facility survey. These cases provide a range of estimates for (1) the number of firms incurring compliance costs and (2) the costs incurred by any firm owning a regulated facility. *Chapter B3: Economic Impact Analysis for Manufacturers* provides a more detailed description of these cases.

Case 1: Upper bound estimate of number of firms owning facilities that face requirements under the regulation; lower bound estimate of total compliance costs that a firm may incur.

For this case, EPA assumed (1) that a firm owns only the regulated sample facility(ies) that it is known to own from the sample analysis and (2) that this pattern of ownership, observed for sampled facilities and their owning firms, extends over the facility population represented by the sample facilities. This case minimizes the possibility of multi-facility ownership by a single firm and thus maximizes the count of affected firms, but also minimizes the potential cost burden to any single firm.

Case 2: Lower bound estimate of number of firms owning facilities that face requirements under the regulation; upper bound estimate of total compliance costs that a firm may incur.

For this case, EPA inverted the prior assumption and assumed that any firm owning a regulated sample facility(ies) owns the known sample facility(ies) and all of the sample weight associated with the sample facility(ies). This case minimizes the count of affected firms, while tending to maximize the potential cost burden to any single firm.

Data in the rest of this section are presented by the industry sector of the firm. EPA determined firm sector based on the sample facilities owned by the firm. If all of the sampled facilities owned by the firm are in the same industry sector, then that industry sector was assigned to the firm. If sample facilities owned by the firm are in more than one industry sector, then the firm was assigned to the "multiple industries" firm sector. As discussed earlier, one known facility in the Other Industries group was found to be owned by a firm that owns facilities in the Primary Manufacturing Industries. This firm is included in the data reported for multiple industries. The remaining 14 entities that were found to own 17 facilities in Other Industries are presented separately.

The number of entities in Primary Manufacturing Industries that would be required to meet the national categorical requirements set by the proposed options varies by option based on the DIF applicability threshold and waterbody type specified in the option. Under the 50 MGD All option, between 46 (Case 2 estimate) and 105 (Case 1 estimate) firms would potentially be subject to Phase III regulation. Under the 200 MGD All option, the number of firms potentially regulated is between 14 (Case 2) and 21 (Case 1). Finally, the 100 MGD CWB option would potentially regulate between 12 (Case 2) and 21 (Case 1) entities. EPA determined that no firms owning regulated 316(b) manufacturing facilities would be small.

Table D1-2 on the following page presents the total number of firms with facilities subject to the national categorical requirements, as well as the number and percentage of those firms determined to be small. The data are shown for the two ownership cases for the three proposed options.

Table D1-2: Number of Firms by Firm Sector and Size (assuming two different ownership cases)

Firm Sector	Case 1: Upper bound estimate of number of firms owning facilities that face requirements under the regulation			Case 2: Lower bound estimate of number of firms owning facilities that face requirements under the regulation		
	Total Number of Firms	Number of Small Firms	Percentage of Firms that are Small	Total Number of Firms	Number of Small Firms	Percentage of Firms that are Small
50 MGD All Option						
Paper	26	-	0.0%	13	-	0.0%
Chemicals	42	-	0.0%	12	-	0.0%
Petroleum	11	-	0.0%	9	-	0.0%
Steel	15	-	0.0%	7	-	0.0%
Aluminum	3	-	0.0%	1	-	0.0%
Multiple Industries	8	-	0.0%	4	-	0.0%
Firms that own facilities in Primary Manufacturing Industries[a,b]	**105**	**-**	**0.0%**	**46**	**-**	**0.0%**
Additional firms that own known facilities in Other Industries[a]	*4*	-	*0.0%*	*4*	-	*0.0%*
200 MGD All Option						
Paper	3	-	0.0%	2	-	0.0%
Chemicals	4	-	0.0%	3	-	0.0%
Petroleum	3	-	0.0%	3	-	0.0%
Steel	7	-	0.0%	2	-	0.0%
Aluminum	0	-	0.0%	0	-	0.0%
Multiple Industries	5	-	0.0%	4	-	0.0%
Firms that own facilities in Primary Manufacturing Industries[a,b]	**21**	**-**	**0.0%**	**14**	**-**	**0.0%**
Additional firms that own known facilities in Other Industries[a]	*1*	-	*0.0%*	*1*	-	*0.0%*
100 MGD CWB Option						
Paper	2	-	0.0%	1	-	0.0%
Chemicals	7	-	0.0%	3	-	0.0%
Petroleum	5	-	0.0%	4	-	0.0%
Steel	3	-	0.0%	1	-	0.0%
Aluminum	0	-	0.0%	0	-	0.0%
Multiple Industries	4	-	0.0%	3	-	0.0%
Firms that own facilities in Primary Manufacturing Industries[a,b]	**21**	**-**	**0.0%**	**12**	**-**	**0.0%**
Additional firms that own known facilities in Other Industries[a]	*1*	-	*0.0%*	*1*	-	*0.0%*

[a] Excludes firms whose only sample facilities close in the baseline.
[b] Individual numbers may not add up to totals due to independent rounding.

Source: U.S. EPA Analysis, 2004.

D1-1.2 Percentage of Small Entities Regulated

As part of its assessment of the small entity impact of the proposed rule on Manufacturers, EPA estimated the percentage of all small entities in the Primary Manufacturing Industries that would be expected to be subject to the national requirements for each of the three proposed options. Because the analysis of facilities in Other Industries is not based on a statistically valid sample, EPA could not estimate the number of entities in Other Industries that would be subject to the regulatory requirements of the proposed options, nor the percentage that are small entities. From its prior analysis of the use of cooling water in industries other than the electric power industry, EPA judges the overall effect and coverage of Phase III regulation in the Other Industries to be minor in relation to the effect and coverage in the five Primary Manufacturing Industries.

EPA used the Statistics of U.S. Businesses (SUSB) published by the Small Business Administration to estimate the total number of manufacturing establishments owned by small firms in each of the five Primary Manufacturing Industries. EPA included all of the SIC industry groups with a sample facility in the five Primary Manufacturing Industries. Based on the SUSB reporting framework, EPA considered all establishments owned by a firm with 500 or fewer employees to be a small entity-owned establishment. This assumption will tend to underestimate the number of small entity-owned establishments in these industry groups because the SBA small entity size criterion is greater than 500 employees for some SIC codes. Underestimating the total number of small entities would result in an overestimate of the percentage of small entities in these industries that subject to Phase III regulation.

EPA estimated that 5,113 entities within the five Primary Manufacturing Industries are small. However, since no small entity is expected to be subject to national requirements under the three proposed options, the percentage of all small entities subject to Phase III regulation is zero.

D1-1.3 Sales Test for Small Entities

In addition to considering the fraction of small entities in each of the affected Manufacturers industries that would be subject to Phase III regulation, EPA also assessed the extent of economic/financial impact on small entities by comparing estimated compliance costs to estimated entity revenue (also referred to as the "sales test"). The analysis is based on the ratio of estimated annualized after-tax compliance costs to annual revenue of the entity. For this analysis, EPA judges that entities for which annualized compliance costs equal or exceed 3% of revenue, might experience a significant economic/financial impact as a result of the regulatory requirements under the three proposed options.

EPA included the following compliance cost categories in this analysis: pilot study capital costs; one-time technology costs of complying with the regulatory requirements; one-time costs of installation downtime; annual operating and maintenance costs; and permitting costs (initial permit costs, annual monitoring costs, and permit reissuance costs). A detailed summary of how these costs were developed is presented in *Chapter B1: Summary of Cost Categories and Key Analysis Elements for Existing Facilities* and *Chapter B3: Economic Impact Analysis for Manufacturers*. EPA collected revenue data for the small entities in EPA's *Detailed Industry Questionnaire*.

In the Manufacturers segment, EPA determined that no small entities would face regulatory requirements under the three proposed options; therefore, no small entities would incur compliance costs or significant economic impact under these options.

D1-2 ANALYSIS OF ELECTRIC GENERATING FACILITIES

EPA's 2000 Section 316(b) *Detailed Industry Questionnaire* (U.S. EPA, 2000) identified 113 Electric Generating facilities potentially subject to Phase III regulation. EPA estimates that three of the 113 sample facilities are baseline closures; these facilities are excluded from this analysis (see *Chapter B5: Economic Impact Analysis for Electric Generators* for more information). The remaining 110 sample facilities represent 114 facilities in the industry.[4] It is impossible, however, to determine the parent entities of extrapolated facilities. The remainder of the small entity analysis for Electric Generators therefore discusses research done for the 110 sample facilities only.

D1-2.1 Small Entity Determination

Similar to the analysis for Manufacturers, the small entity determination for Electric Generators was conducted in two steps:

- Identify the domestic parent entity of the 110 sample facilities.
- Determine the size of the entities owning the 110 sample facilities.

a. Identification of Domestic Parent Entities

As previously described for Manufacturers, the RFA analysis is conducted at the highest level of domestic ownership, referred to as the "domestic parent entity." EPA first identified the immediate owner of the 110 sample Phase III Generators using the 2001 Form EIA-860 (U.S. DOE, 2001a). The immediate owners of power plants can be classified into one of the following seven categories: investor-owned utility (IOU), nonutility, Federal utility, State authority, municipality, political subdivision, or rural electric cooperative. IOUs and nonutilities are private businesses; Federal utilities, State authorities, municipalities, and political subdivisions are public sector entities; and rural electric cooperatives are not-for-profit enterprises.[5] EPA conducted research to determine changes in facility- and entity-level ownership in order to identify the correct domestic parent entity of each potential Phase III Electric Generator. EPA incorporated known ownership changes through the 2002 calendar year, but did not incorporate changes in facility/entity ownership that occurred after 2002 to maintain consistency in its analyses.

Public sector entities and electric cooperatives are generally not owned by other entities. EPA therefore assumed that these entities are the domestic parents of the facilities that they own. IOUs and nonutilities, on the other hand, are often 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" (Census, 2002). To determine the domestic parent entity for potential Phase III Generators owned by an IOU or a nonutility, 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 U.S. Securities and Exchange Commission's (SEC) *FreeEdgar* database; corporate websites; and Dun and Bradstreet data (U.S. DOE, 2001a; SEC, 2004; D&B, 2003).

EPA determined that 72 unique domestic parent entities own the 110 sample Electric Generators.

b. Size Determination of Domestic Parent Entities

Different size thresholds apply to different types of entity (i.e., private businesses, public sector entities, and not-for-profit enterprises). Therefore, EPA used multiple data sources to determine the sizes of the Phase III domestic parent entities:

[4] EPA applied sample weights to the 113 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).

[5] No political subdivisions were found to be subject to the national categorical requirements under any of the evaluated options. Political subdivisions are therefore not discussed in this chapter.

- For ***private*** businesses (including IOUs 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).[6] The SBA standards are based on employment, sales revenue, or total electric output (in megawatt hours, MWh), by 4-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 for private businesses: 10-K filings available through the U.S. Securities and Exchange Commission's (SEC) *FreeEdgar* database, 1999 - 2001 EIA Form-860, U.S. Census Data, and company websites (D&B, 2003; SEC, 2004; U.S. DOE, 2001a; Census, 2003). Table D1-5 presents the unique firm-level SIC codes and the corresponding SBA size standards for Electric Generators 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*** 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 were obtained from the U.S. Census Bureau (Census, 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 1999 - 2001 Form EIA-861 (U.S. DOE, 2001b).

Table D1-3 presents the unique firm-level 4-digit SIC codes and corresponding SBA size standards that were used to determine the size of the entities that own Electric Generating facilities potentially subject to Phase III regulation

Table D1-3: Unique 4-Digit Firm-Level SIC Codes and SBA Size Standards for Electric Generators

SIC Code	SIC Description	SBA Size Standard
1311	Crude Petroleum and Natural Gas	500 Employees
1542	General Contractors – Nonresidential Buildings, Other than Industrial Buildings and Warehouses	$27.5 Million
2621	Paper Mills	750 Employees
4911	Electric Services	4 million MWh
4924	Natural Gas Distribution	500 Employees
4925	Mixed, Manufactured, or Liquefied Petroleum Gas Production and/or Distribution	$5.0 Million
4932	Gas and Other Services Combined	$5.0 Million
4953	Refuse Systems	$10.0 Million
6211	Security Brokers, Dealers and Flotation Companies	$5.0 Million
9111	Executive Offices	50,000 Population

Source: U.S. SBA, 2000.

[6] For a comparison of the small entity determination using SIC codes and NAICS codes, respectively, see Appendix 2 to this chapter.

Based on these size thresholds, EPA determined that 13 out of the 72 parent entities owning the 110 sample facilities are small entities. Nine of the 13 small entities are municipalities, two are nonutilities, and two are rural cooperatives.

Under the proposed options, the minimum applicability threshold for national categorical requirements is 50 MGD or greater. Since Electric Generators with a DIF of 50 MGD or greater were covered by Phase II regulation, no Phase III Generator would be subject to the national categorical requirements under any of the proposed options.

D1-2.2 Percentage of Small Entities Regulated

As part of its assessment of the small entity impact of the proposed rule on Electric Generators, EPA compared the number of small entities potentially subject to Phase III regulation to the number of small entities in the entire industry. While no small entities would be subject to the national categorical requirements under any of the proposed options, some of the other evaluated options would regulate small entities. This analytical step is therefore relevant to the other evaluated options only.

EPA estimated the total number of small entities in the United States using information collected by the Energy Information Administration (EIA). Based on Form EIA-861, 858 unique IOUs, Federal utilities, State authorities, municipalities, and rural electric cooperatives operated electric power plants in the United States in 2001. In addition, there were 2,127 nonutilities in 2001 (U.S. DOE, 2001a). EPA determined the entity sizes for rural electric cooperatives based on their total electricity sales for 2001, as reported in Form EIA-861. All Federal utilities and State authorities are assumed to be large. As described above, EPA researched holding company information for Phase III IOUs and nonutilities, and population data for Phase III municipalities. It was not feasible to conduct the same research for all those types of entities in the entire industry. EPA therefore used a combination of methods to estimate the number of small IOUs, nonutilities, and municipalities operating in the Electric Generating industry:

- ***Investor-owned entities:*** EPA determined which IOUs would be considered small based on the electric output threshold of 4 million MWh, using the 2001 Form EIA-861. However, EPA's analysis of the domestic parent entity size of Section 316(b) IOUs (both for Phases II and III) showed that the small entity determination based on the 4 million MWh threshold is not always the same as that based on the holding company's SIC code. EPA identified seven IOU-owned Phase II and Phase III Generators that would qualify as small entities based on the 4 million MWh total electric output threshold.[7] However, EPA's holding company research showed that only one of these seven IOUs, or 14%, would also be considered small at the holding company level. EPA therefore estimates that industry-wide only 14% of private entities that are small at the IOU 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 86%. Using this method, EPA estimates that six investor-owned entities in the Electric Generating industry are small.

- ***Municipalities:*** EPA determined which municipalities would be considered small based on the electric output threshold of 4 million MWh, using the 2001 Form EIA-861 data. As with IOUs, EPA's analysis of Section 316(b) municipalities (both for Phases II and III) showed that the small entity determination based on the 4 million MWh threshold is not always the same as that based on population. EPA's research of municipalities owning facilities potentially subject to Phase III regulation, showed that 44 municipalities would be small based on the 4 million MWh size standard.[8] Of these 44 entities, 26, or 59%, would also be considered small when using the population threshold. EPA therefore estimates,

[7] EPA used information on small IOUs from both Phase II (five) and Phase III (two) to adjust the number of small IOUs in the Electric Generating industry.

[8] EPA used information on small in-scope municipalities from both Phase II (30) and Phase III (14) to adjust the number of small municipalities in the Electric Generating industry.

industry-wide, that only 59% of small municipalities, 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 41%. Using this method, EPA estimates that 302 municipalities in the Electric Generating industry are small.

The adjustments made to IOU and municipality size determinations are based on the assumption that Section 316(b) IOUs and municipalities are representative of the EIA universe of electric utilities (for IOUs in terms of their respective sizes at the utility level and the holding company level; for municipalities in terms of their respective sizes based on electric output and population). If this is not the case, the industry-wide estimate of small IOUs and municipalities may be over- or underestimated.

- ***Nonutilities:*** Electric output data or other information to determine the entity sizes of nonutilities are not available from the EIA or other public data sources. As a result, EPA estimated a range of the number of small nonutilities based on two methods: (1) EPA assumed that the proportion of small nonutilities in the industry as a whole is the same as the proportion of small nonutilities potentially subject to Phase III regulation (i.e., two out of 26, or 7.7%);[9] and (2) EPA assumed that the proportion of small nonutilities in the industry as a whole is the same as the proportion of total IOUs, municipalities, political subdivisions, and rural electric cooperatives estimated to be small based on electric output (i.e., 412 of 817, or 50.4%). Using these two methods, EPA estimates that between 132 and 866 nonutilities within the entire Electric Generating industry are small.

EPA estimates that the total number of small entities in the Electric Generating industry is between 544 and 1,278. However, since no small entities would be subject to the national categorical requirements under any of the proposed options, the percentage of all small entities subject to Phase III regulation is zero.

D1-2.3 Sales Test for Small Entities

As previously described for Manufacturers, the final step in the RFA analysis consists of analyzing the cost-to-revenue ratio of each small entity subject to Phase III regulation (also referred to as the "sales test"). The analysis is based on the ratio of each parent entity's aggregated after-tax compliance costs (summed over each facility owned by the parent entity and subject to the national categorical requirements) to its total sales revenue. EPA used a threshold of 3% to determine entities that might experience a significant economic impact as a result of Phase III regulation.

The estimated annualized after-tax compliance costs include all direct costs incurred by facilities: pilot study capital costs; one-time technology costs of complying with the Phase III regulation; one-time costs of installation downtime; annual operating and maintenance costs; and permitting costs (initial permit costs, annual monitoring costs, and permit reissuance costs). A detailed summary of how these costs were developed is presented in *Chapter B1: Summary of Cost Categories and Key Analysis Elements for Existing Facilities* and *Chapter B5: Economic Impact Analysis for Electric Generators*. None of the small entities that own facilities potentially subject regulation owns more than one Electric Generating facility. Therefore, no small entity would be expected to incur compliance costs for more than one facility under any of the evaluated options.

EPA collected revenue data for the small entities with potentially regulated Phase III Electric Generators from one of several sources, listed in order of preference: (1) Dun and Bradstreet, (2) average utility revenue (1999-2001) from Form EIA-861, and (3) other sources such as company annual reports or websites (D&B, 2003; U.S. DOE, 2001b).

As previously noted, Electric Generating facilities with a DIF of 50 MGD or greater, the minimum DIF applicability threshold of the three proposed options, were covered under the final Section 316(b) Phase II rule. Therefore, no Electric Generators are regulated or incur compliance costs under any of the proposed options.

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[9] The 26 nonutilities are the immediate owners of the 31 Phase III nonutility facilities. These 26 nonutilities are owned by the 21 entities presented in Table D1-6.

D1-3 Analysis of New Offshore Oil and Gas Extraction Facilities

This section discusses EPA's analysis of potential small entity impacts of the proposed rule on the new offshore oil and gas extraction industry segment. The proposed Phase III regulation for new offshore oil and gas extraction facilities is based on a 2 MGD DIF applicability threshold and would regulate an estimated 124 new offshore oil and gas extraction facilities.

D1-3.1 Small Entity Determination

EPA used the information on existing small entities in the offshore oil and gas extraction industry to estimate the number of small entities associated with new facilities. EPA identified 24 small entities currently operating mobile offshore drilling units or platforms that could potentially be regulated by the proposed option for new facilities, should they construct new MODUs or platforms similar to those currently in operation.

a. Mobile Offshore Drilling Units (MODUs)

EPA first identified the operating companies of existing MODUs operating in the Gulf of Mexico and the number of rigs owned by each company. EPA then linked these operating companies to their domestic parent companies. EPA identified 21 parent firms potentially affected by the proposed rule for new facilities (see Table C2-2 in *Chapter C2: Profile of the Offshore Oil and Gas Extraction Industry*). These affiliations were determined primarily on the basis of Security and Exchange Commission (SEC) data using the *FreeEdgar* database, on which all filings of publicly held firms are available (SEC, 2004). The 10-K and 8-K reports were the primary sources used to collect this information. The 10-K annual reports generally list significant subsidiaries of the parent company and are the source of income statement and balance sheet information used for characterizing financial conditions at a firm. The subsidiary lists were used to confirm ownership relationships. The 8-K forms, in which significant changes to the firm must be announced, are often the source of information on mergers and acquisitions.

EPA identified the NAICS code for each of the domestic parent companies currently operating a MODU in the Gulf of Mexico and the SBA size standard for each code. Table D1-4 shows that of the 21 parent entities operating MODUs in the Gulf of Mexico, only two entities could be identified as small. These companies own approximately 0.5% of all MODUs operating in the Gulf of Mexico.

Table D1-4: Unique 4-Digit Firm-Level SIC Codes, NAICS Classification, and SBA Size Standards for Mobile Offshore Drilling Units

SIC Code	NAICS Code	NAICS Title	SBA Size Standard	Total Number of Firms[a]	
				Small	Large
1311	211111	Crude Petroleum and Natural Gas Extraction	500 employees	2	-
1381	213111	Drilling Oil and Gas Wells	500 employees	-	6
1389	213112	Support Activities for Oil and Gas Operations	$7.5 million in revenues	-	1
2819	211112	Natural Gas Liquid Extraction	500 employees	-	1

[a] Does not include seven foreign firms and four unknown firms for which NAICS or SIC codes could not be located in publicly available data.

Source: SEC Edgar Database; 10K filings; 13 CFR Part 121.

EPA estimates that 80 jack-up MODUs, 20 semi-submersible MODU, and three drillships will be built during the entire 20-year period of analysis, for a total of 103 new sources (see *Chapter C2: Profile of the Offshore Oil and Gas Extraction Industry* for a detailed discussion of the estimated number of new MODUs). Given that large companies currently operate approximately 99.5% of the existing facilities, EPA estimates that no small entities will be building new MODUs potentially subject to Phase III regulation.

b. Platforms

❖ ***Gulf of Mexico***

EPA determined, based on data from the Bureau of Land Management's Minerals Management Service (MMS), that, on average, one potentially regulated structure is built per year in the deepwater portion of the Gulf of Mexico. EPA therefore estimates that 20 structures will be constructed over the time frame of the analysis. With the exception of a few subsea completions, which do not operate potentially regulated CWIS, only large firms have built structures in the deepwater Gulf of Mexico. This trend is likely to continue, given the resources required to construct deepsea structures, which sometimes exceed $1 billion dollars (EPA 821-B-00-012). Therefore, all of these structures are assumed to be constructed by large firms.

❖ ***California***

EPA does not project any platforms off the California coast to be constructed during the time period of evaluation. Therefore, no small entities owning platforms in this area would be affected by this rule.

❖ ***Alaska***

In Cook Inlet, Alaska, only one new platform has been constructed in the last 16 years. Most new exploration and development in this region takes place from existing infrastructure or from onshore locations. No definitive plans appear to be in place for any new platforms in State waters. In Federal waters, lower Cook Inlet is a source of potential activity, since MMS completed a lease bid in April, 2004. However, given the long lead times between lease bid to operation, it may be unlikely that this lease bid will result in new platforms during the time frame of the analysis. To be conservative, however, EPA assumes that one such platform might be constructed in either Federal or State waters and begin operation in 2014. In other Federal areas in the Alaska region, little new activity is underway. BP has dropped plans for its Liberty project in the Beaufort Sea area. Although some leases are actively registered in the Beaufort Sea, the time frame for development, if any is undertaken, is likely to be beyond the time frame of this analysis. Because the most recently installed platform in Cook Inlet was built by a small entity, EPA projects that one small entity in Alaska would potentially be affected by the rule. This platform is estimated to have a DIF of greater than 2 MGD.

In summary, EPA projects that 20 new deepwater platforms in the Gulf of Mexico and one new platform in Cook Inlet would be potentially regulated under the proposed rule. All new platforms expected to be built in the Gulf of Mexico are assumed to be owned by large entities. The one new platform expected to be built in Cook Inlet is assumed to be owned by a small entity. For more information on oil and gas platforms, including profiles and projections for the number and type of new facilities estimated to begin operation, see *Chapter C2: Profile of the Offshore Oil and Gas Extraction Industry.*

D1-3.2 Percentage of Small Entities Regulated

Due to the capital requirements for constructing a new MODU or platform with a DIF of 2 MGD or more, very few small businesses are expected to be affected by the proposed rule. For existing offshore oil and gas extraction facilities, EPA identified two small businesses operating MODUs, 21 small businesses operating platforms in the Federal Gulf of Mexico waters, and one small business operating a platform in Cook Inlet, Alaska for a total of 24 small businesses (four MODU owners and 37 platform owners could not be identified as small or large, since no financial data on these firms were publicly available). EPA estimates one small entity would potentially be subject to the proposed rule for new offshore oil and gas extraction facilities. Therefore, one of 24 identified small entities in the offshore oil and gas extraction industry (4%) is estimated to be subject to Phase III regulation.

D1-3.3 Sales Test for Small Entities

There are no small entities projected to build new MODUs or deepwater platforms in the Gulf of Mexico that are potentially subject to the proposed rule. In Alaska, Forest Oil is considered the likeliest type of firm to build an Alaska platform during the time frame of the analysis. In 2002, Forest Oil reported revenues of $2,450 million. The annualized pre-tax costs of compliance applied to all known affected or potentially affected structures owned by Forest Oil are $0.28 million and the annualized after-tax costs are $0.21 million. The cost-to-revenue ratio for the one small entity projected to be in scope of the proposed rule is therefore approximately 0.012% pre-tax or 0.008% after-tax.

D1-4 SUMMARY OF REGULATORY FLEXIBILITY ANALYSIS

The RFA analysis, conducted in developing this proposed rule, is summarized in Table D1-5 on the following page. No small entity would be subject to the national categorical requirements for existing facilities under any of the three proposed options. Only one small entity would be subject to the national categorical requirements for new offshore oil and gas extraction facilities under the proposed rule. This small entity is estimated to incur compliance costs of less than 0.1% of annual revenues. As a result of this analysis, EPA concluded that the proposed rule would not have a significant economic impact on a substantial number of small entities

Table D1-5: Summary of Small Entity Impact Ratio Ranges by Sector

Industry	Total Number of Small Entities	Number of Small Entities Owning Facilities Potentially Subject to Regulation	Percentage of Small Entities Subject to Regulation	Compliance Cost/Annual Revenues		
				0-1%	1-3%	>3%
Proposed Options for Existing Facilities / 2 MGD Option for New OOGE Facilities						
Manufacturers	5,113	-	0.0%	-	-	-
Electric Generators	543 - 1,295	-	0.0%	-	-	-
New OOGE Facilities	24	1	4.2%	1	-	-
Total	**5,680 - 6,432**	**1**	**0.0%**	**1**	**0**	**0**

Source: U.S. EPA Analysis, 2004.

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Appendix 1 to Chapter D1: Summary of Results for Alternative Options

This appendix presents the results of the RFA analysis for the other options for existing facilities which were evaluated in developing the proposed rule. For all options, facility counts and other results only include those Phase III existing facilities that are (1) non-baseline closures and (2) subject to national categorical requirements under the option. See *Chapter B3: Economic Impact Analysis for Manufacturers* and *Chapter B5:Economic Impact Analysis for Electric Generators* for more information on baseline closures and counts of facilities subject to national categorical requirements under each option. See the main body of this chapter for a description of data sources and methodologies used in these analyses.

In Table D1A-1 below, the other evaluated options for existing facilities are presented in order of increasing stringency and/or applicability (e.g., the largest number of facilities would be subject to the national requirements under Option 6, compared to any of the other evaluated options). As discussed in the main chapter, the estimates of the total number of regulated small entities and the percentage of all small entities subject to Phase III regulation *exclude* consideration of entities in Other Industries within the Manufacturers segment (see section D1-1.2). However, the estimated number of small entities incurring costs in the three cost-to-revenue ranges *include* the known number of small entities owning known facilities in Other Industries.

Table D1A-1: Summary of Small Entity Impact Ratio Ranges for Existing Facilities by Sector

Industry	Total Number of Small Entities	Number of Small Entities Owning Facilities Potentially Subject to Regulation	Percentage of Small Entities Subject to Regulation	Compliance Cost/Annual Revenues		
				0-1%	1-3%	>3%
Option 3						
Manufacturers[a,b]	5,113	3	0.1%	4	-	-
Electric Generators	543 - 1,295	9	0.7% - 1.7%	6	3	-
Total[c]	**5,656 - 6,408**	**12**	**0.2%**	**10**	**3**	**-**
Option 4						
Manufacturers[a,b]	5,113	1	0.0%	1	-	-
Electric Generators	543 - 1,295	2	0.2% - 0.4%	-	1	1
Total[c]	**5,656 - 6,408**	**3**	**0.0%-0.1%**	**1**	**1**	**1**
Option 2						
Manufacturers[a,b]	5,113	3	0.1%	4	-	-
Electric Generators	543 - 1,295	9	0.7% - 1.7%	5	3	1
Total[c]	**5,656 - 6,408**	**12**	**0.2%**	**9**	**3**	**1**
Option 1						
Manufacturers[a,b]	5,113	3	0.1%	4	-	-
Electric Generators	543 - 1,295	9	0.7% - 1.7%	4	4	1
Total[c]	**5,656 - 6,408**	**12**	**0.2%**	**8**	**4**	**1**

Table D1A-1: Summary of Small Entity Impact Ratio Ranges for Existing Facilities by Sector

Industry	Total Number of Small Entities	Number of Small Entities Owning Facilities Potentially Subject to Regulation	Percentage of Small Entities Subject to Regulation	Compliance Cost/Annual Revenues		
				0-1%	1-3%	>3%
			Option 6			
Manufacturers[a,b]	5,113	10	0.2%	12	1	-
Electric Generators	543 - 1,295	13	1.0% - 2.4%	7	5	1
Total[c]	**5,656 - 6,408**	**23**	**0.4%**	**19**	**6**	**1**

[a] For Manufacturers, the more conservative cost analysis (Case 2 estimate) is presented, which is likely to overstate the compliance costs that would be incurred by any single small entity but may understate the number of small entities incurring compliance costs.

[b] For Manufacturers, the “Total Number of Small Entities” and the “Number of Small Entities Owning Facilities Potentially Subject to Regulation” *exclude* entities in Other Industries; the numbers presented in the cost-to-revenue ranges *include* known entities in Other Industries.

[c] Individual numbers may not sum to reported totals due to independent rounding.

Source: U.S. EPA Analysis, 2004.

Appendix 2 to Chapter D1: Small Business Determinations Based on NAICS Codes

CHAPTER CONTENTS

INTRODUCTION

As discussed in Chapter D1, the SBA small business size standards changed from a SIC code-based system to a NAICS code-based system on October 1, 2000. Because EPA conducted its data collection effort for existing facilities before this change, EPA performed the small entity analysis for existing facilities based on SIC codes. This appendix presents an analysis to determine whether use of NAICS code-based size standards would affect the results of the small entity analysis.

D1A2-1 IDENTIFYING NAICS CODES AND THRESHOLDS

EPA started with the unique firm-level 4-digit SIC codes for firms that own existing facilities potentially subject to Phase III regulation (see Tables D1-1 and D1-3). EPA used information from the Economic Census, *1997 Economic Census: Bridge Between NAICS and SIC*, to determine 1997 NAICS Codes classifications for these firms.[1] EPA also used an additional Economic Census publication/dataset, *1997 NAICS Matched to 2002 NAICS*, to bring the data forward to NAICS 2002 so that the most current small business thresholds could be used (Census, 2003). Table D1A2-1 presents firm-level SIC codes, SIC code descriptions, SIC code-based small business thresholds, as well as the corresponding NAICS codes, NAICS code descriptions, and NAICS code-based small business thresholds. For ease of reference, gray shading is used to highlight SIC codes with corresponding NAICS code that have a different size standard.

Table D1A2-1: Small Business Thresholds Based on SIC Codes and NAICS Codes

SIC Code	SIC Code Description	SIC Size Standards (employees/ $millions)	NAICS Code	NAICS Code Description	NAICS Size Standards (employees/ $millions)
0133	Sugarcane and Sugar Beets	$0.5	111991	Sugar Beet Farming	$0.75
			111930	Sugarcane Farming	$0.75
1011	Iron Ores	500	212210	Iron Ore Mining	500
1311	Crude Petroleum and Natural Gas.	500	211111	Crude Petroleum and Natural Gas Extraction	500
1542	General Contractors – Nonresidential Buildings, Other than Industrial Buildings and Warehouses	$27.5	236220	Commercial and Institutional Building Construction	$28.50
2011	Meat Packing Plants	500	311611	Animal (except Poultry)	500

[1] Two different bridges are available from Census. One provides a bridge based on the processes/activities performed and the other bridge is based on establishment classifications. This analysis uses the bridge based on establishment classifications (Census, 2000).

Table D1A2-1: Small Business Thresholds Based on SIC Codes and NAICS Codes

SIC Code	SIC Code Description	SIC Size Standards (employees/ $millions)	NAICS Code	NAICS Code Description	NAICS Size Standards (employees/ $millions)
				Slaughtering	
2046	Wet Corn Milling	750	311221	Wet Corn Milling	750
2061	Cane Sugar, Except Refining	500	311311	Sugarcane Mills	500
2062	Cane Sugar Refining	750	311312	Cane Sugar Refining	750
2063	Beet Sugar	750	311313	Beet Sugar Manufacturing	750
2075	Soybean Oil Mills	500	311222	Soybean Processing	500
			311225	Fats and Oils Refining and Blending	1,000
2211	Broadwoven Fabric Mills, Cotton	1,000	313210	Broadwoven Fabric Mills	1,000
2421	Sawmills and Planing Mills, General	500	321113	Sawmills	500
			321912	Cut Stock, Resawing Lumber, and Planing	500
			321918	Other Millwork(including Flooring)	500
			321999	All Other Miscellaneous Wood Product Manufacturing	500
2611	Pulp Mills	750	322110	Pulp Mills	750
2621	Paper Mills	750	322121	Paper (except Newsprint)Mills	750
		750	322122	Newsprint Mills	750
2631	Paperboard Mills	750	322130	Paperboard Mills	750
2653	Corrugated and Solid Fiber Boxes	500	322211	Corrugated and Solid Fiber Box Manufacturing	500
2673	Plastics, Foil, and Coated Paper Bags	500	322223	Plastics, Foil, and Coated Paper Bag Manufacturing	500
			326111	Unsupported Plastics Bag Manufacturing	500
2679	Converted Paper and Paperboard Products, N.E.C.	500	322222	Coated and Laminated Paper Manufacturing	500
			322231	Die-Cut Paper and Paperboard Office Supplies Manufacturing	500
			322299	All Other Converted Paper Product Manufacturing	500
2711	Newspapers: Publishing, or Publishing and Printing	500	516110	Internet Publishing and Broadcasting	500
2812	Alkalies and Chlorine	1,000	325181	Alkalis and Chlorine Manufacturing	1,000
2813	Industrial Gases	1,000	325120	Industrial Gas Manufacturing	1,000

Table D1A2-1: Small Business Thresholds Based on SIC Codes and NAICS Codes

SIC Code	SIC Code Description	SIC Size Standards (employees/ $millions)	NAICS Code	NAICS Code Description	NAICS Size Standards (employees/ $millions)
2819	Industrial Inorganic Chemicals, N.E.C.	1,000	325131	Inorganic Dye and Pigment Manufacturing	1,000
			325188	All Other Basic Inorganic Chemical Manufacturing	1,000
			325998	All Other Miscellaneous Chemical Product and Preparation Manufacturing	500
			331311	Alumina Refining	1,000
2821	Plastics Materials, Synthetic Resins, and Nonvulcanizable Elastomers	750	325211	Plastics Material and Resin Manufacturing	750
2824	Manmade Organic Fibers, Except Cellulosic	1,000	325222	Noncellulosic Organic Fiber Manufacturing	1,000
2833	Medicinal Chemicals and Botanical Products	750	325411	Medicinal and Botanical Manufacturing	750
2834	Pharmaceutical Preparations	750	325412	Pharmaceutical Preparation Manufacturing	750
2851	Paints, Varnishes, Lacquers, Enamels, and Allied Products	500	325510	Paint and Coating Manufacturing	500
2869	Industrial Organic Chemicals, N.E.C.	1,000	325110	Petrochemical Manufacturing	1,000
			325120	Industrial Gas Manufacturing	1,000
			325188	All Other Basic Inorganic Chemical Manufacturing	1,000
			325193	Ethyl Alcohol Manufacturing	1,000
			325199	All Other Basic Organic Chemical Manufacturing	1,000
2873	Nitrogenous Fertilizers	1,000	325311	Nitrogenous Fertilizer Manufacturing	1,000
2874	Phosphatic Fertilizers	500	325312	Phosphatic Fertilizer Manufacturing	500
2891	Adhesives and Sealants	500	325520	Adhesive Manufacturing	500
2899	Chemicals and Chemical Preparations, N.E.C.	500	311942	Spice and Extract Manufacturing	500
			325199	All Other Basic Organic Chemical Manufacturing	1,000
			325510	Paint and Coating Manufacturing	500
			325998	All Other Miscellaneous Chemical Product and Preparation Manufacturing	500
2911	Petroleum Refining	1,500	324110	Petroleum Refineries	1,500[a]
3312	Steel Works, Blast Furnaces (Including Coke Ovens), and Rolling Mills	1,000	324199	All Other Petroleum and Coal Products Manufacturing	500
			331111	Iron and Steel Mills	1,000

Table D1A2-1: Small Business Thresholds Based on SIC Codes and NAICS Codes

SIC Code	SIC Code Description	SIC Size Standards (employees/ $millions)	NAICS Code	NAICS Code Description	NAICS Size Standards (employees/ $millions)
3313	Electrometallurgical Products, Except Steel	750	331112	Electrometallurgical Ferroalloy Product Manufacturing	750
			331492	Secondary Smelting, Refining, and Alloying of Nonferrous Metal (except Copper and Aluminum)	750
3315	Steel Wiredrawing and Steel Nails and Spikes	1,000	331222	Steel Wire Drawing	1,000
			332618	Other Fabricated Wire Product Manufacturing	500
3316	Cold-Rolled Steel Sheet, Strip, and Bars	1,000	331221	Cold-Rolled Steel Shape Manufacturing	1,000
3317	Steel Pipe and Tubes	1,000	331210	Iron and Steel Pipe and Tube Manufacturing from Purchased Steel	1,000
3334	Primary Production of Aluminum	1,000	331312	Primary Aluminum Production	1,000
3339	Primary Smelting and Refining of Nonferrous metals, Except Copper and Aluminum	750	331419	Primary Smelting and Refining of Nonferrous Metal (except Copper and Aluminum)	750
3353	Aluminum Sheet, Plate, and Foil	750	331315	Aluminum Sheet, Plate and Foil Manufacturing	750
			332996	Fabricated Pipe and Pipe Fitting Manufacturing	500
3421	Cutlery	500	332211	Cutlery and Flatware (except Precious) Manufacturing	500
3714	Motor Vehicle Parts and Accessories	750	336211	Motor Vehicle Body Manufacturing	1,000
			336312	Gasoline Engine and Engine Parts Manufacturing	750
			336322	Other Motor Vehicle Electrical and Electronic Equipment Manufacturing	750
			336330	Motor Vehicle Steering and Suspension Components (except Spring) Manufacturing	750
			336340	Motor Vehicle Brake System Manufacturing	750
			336350	Motor Vehicle Transmission and Power Train Parts Manufacturing	750
			336399	All Other Motor Vehicle Parts Manufacturing	750

Table D1A2-1: Small Business Thresholds Based on SIC Codes and NAICS Codes

SIC Code	SIC Code Description	SIC Size Standards (employees/ $millions)	NAICS Code	NAICS Code Description	NAICS Size Standards (employees/ $millions)
3728	Aircraft Parts and Auxiliary Equipment, N.E.C.	1,000	332912	Fluid Power Valve and Hose Fitting Manufacturing	500
			333995	Fluid Power Cylinder and Actuator Manufacturing	500
			333996	Fluid Power Pump and Motor Manufacturing	500
			336413	Other Aircraft Part and Auxiliary Equipment Manufacturing	1,000[b]
3861	Photographic Equipment and Supplies	500	325992	Photographic Film, Paper, Plate and Chemical Manufacturing	500
			333315	Photographic and Photocopying Equipment Manufacturing	500
3999	Manufacturing Industries, N.E.C.	500	314999	All Other Miscellaneous Textile Product Mills	500
			316110	Leather and Hide Tanning and Finishing	500
			321999	All Other Miscellaneous Wood Product Manufacturing	500
			322299	All Other Converted Paper Product Manufacturing	500
			323110	Commercial Lithographic Printing	500
			323111	Commercial Gravure Printing	500
			323112	Commercial Flexographic Printing	500
			323113	Commercial Screen Printing	500
			323119	Other Commercial Printing	500
			325998	All Other Miscellaneous Chemical Product and Preparation Manufacturing	500
			326199	All Other Plastics Product Manufacturing	500
			332212	Hand and Edge Tool Manufacturing	500
			332999	All Other Miscellaneous Fabricated Metal Product Manufacturing	500
			335121	Residential Electric Lighting Fixture Manufacturing	500
			337127	Institutional Furniture Manufacturing	500
			339999	All Other Miscellaneous Manufacturing	500

Table D1A2-1: Small Business Thresholds Based on SIC Codes and NAICS Codes

SIC Code	SIC Code Description	SIC Size Standards (employees/ $millions)	NAICS Code	NAICS Code Description	NAICS Size Standards (employees/ $millions)
4911	Electric Services	4 million megawatt hrs.	221111	Hydroelectric Power Generation1	4 million megawatt hrs.[c]
			221112	Fossil Fuel Power Generation1	4 million megawatt hrs.[c]
			221113	Nuclear Electric Power Generation1	4 million megawatt hrs.[c]
			221119	Other Electric Power Generation1	4 million megawatt hrs.[c]
			221121	Electric Bulk Power Transmission and Control	4 million megawatt hrs.[c]
			221122	Electric Power Distribution	4 million megawatt hrs.[c]
4924	Natural Gas Distribution	500	221210	Natural Gas Distribution	500
4925	Mixed, Manufactured, or Liquefied Petroleum Gas Production and/or Distribution	$5	221210	Natural Gas Distribution	500
4932	Gas and Other Services Combined	$5	221210	Natural Gas Distribution	500
4953	Refuse Systems	$10	562920	Materials Recovery Facilities	$10.50
			562211	Hazardous Waste Treatment and Disposal	$10.50
			562212	Solid Waste Landfill	$10.50
			562213	Solid Waste Combustors and Incinerators	$10.50
			562219	Other Nonhazardous Waste Treatment and Disposal	$10.50
5153	Grain and Field Beans	100	425120	Wholesale Trade Agents and Brokers	100
			424510	Grain and Field Bean Merchant Wholesalers	100
			425110	Business to Business Electronic Markets	100
5171	Petroleum Bulk Stations and Terminals	100	424710	Petroleum Bulk Stations and Terminals	100
			454311	Heating Oil Dealers	$10.50
			454312	Liquefied Petroleum Gas (Bottled Gas) Dealers	$6.00
6141	Personal Credit Institutions	$5	522120	Savings Institutions	$150 million in assets[d]
			522210	Credit Card Issuing	$150 million in assets[d]
			522220	Sales Financing	$6.00
			522291	Consumer Lending	$6.00

Table D1A2-1: Small Business Thresholds Based on SIC Codes and NAICS Codes

SIC Code	SIC Code Description	SIC Size Standards (employees/ $millions)	NAICS Code	NAICS Code Description	NAICS Size Standards (employees/ $millions)
6211	Security Brokers, Dealers and Flotation Companies	$5	523110	Investment Banking and Securities Dealing	$6.00
			523120	Securities Brokerage	$6.00
			523910	Miscellaneous Intermediation	$6.00
			523999	Miscellaneous Financial Investment Activities	$6.00
6719	Offices of Holding Companies, N.E.C.	$5	551112	Offices of Other Holding Companies	$6.00
9111	Executive Offices	50,000 Population	921110	Executive Offices	50,000 Population

Notes (from source SBA publications):

[a] For purposes of Government procurement, the petroleum refiner must be a concern that has no more than 1,500 employees nor more than 125,000 barrels per calendar day total Operable Atmospheric Crude Oil Distillation capacity. Capacity includes owned or leased facilities as well as facilities under a processing agreement or an arrangement such as an exchange agreement or a throughput. The total product to be delivered under the contract must be at least 90 percent refined by the successful bidder from either crude oil or bona fide feedstocks.

[b] Contracts for the rebuilding or overhaul of aircraft ground support equipment on a contract basis are classified under NAICS code 336413.

[c] A firm is small if, including its affiliates, it is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt hours.

[d] A financial institution's assets are determined by averaging the assets reported on its four quarterly financial statements for the preceding year. "Assets" for the purposes of this size standard means the assets defined according to the Federal Financial Institutions Examination Council 034 call report form.

Source: U.S. SBA, 2000; U.S. SBA, 2002.

D1A2-2 DIFFERENCES IN NAICS-BASED AND SIC-BASED SIZE THRESHOLDS

As a second step, EPA identified all potential Phase III firms whose SIC code-based small business threshold differs from the NAICS code-based one. There are two possible cases:

(1) the NAICS threshold is greater than the SIC threshold, which could lead to additional firms being classified as small businesses, and

(2) the NAICS threshold is less than the SIC threshold, which could lead to fewer firms being classified as small businesses.

For each such firm, EPA examined whether the firm's initial business size classification, based on the SIC code-based criteria, would change under the NAICS code-based criteria.

Table D1A2-2 lists SIC codes for which the NAICS threshold exceeds the SIC threshold and therefore could potentially lead to additional facilities being classified as small. The table shows that there are 13 potentially affected firms, in 11 SIC codes, that fall into that category. Table D1A2-3 lists SIC codes for which the NAICS threshold is less than the SIC threshold and therefore could potentially lead to fewer facilities being classified as small. The table shows that there are 17 potentially affected firms, in six SIC codes, that fall into that category.

Table D1A2-2: NAICS Thresholds Exceed SIC Thresholds Additional Firms May Be Classified as Small

SIC Code	SIC Code Threshold	NAICS Code(s)	NAICS Code Threshold	Number of Potentially Affected Firms
0133	$0.5 million	111991; 111930	$0.75 million	1
1542	$27.5 million	236220	$28.5 million	1
2075	500 Employees	311225	1,000 Employees	1
2899	500 Employees	325199	1,000 Employees	1
3714	750 Employees	336211	1,000 Employees	1
4925	$5.0 million	221210	500 Employees	1
4932	$5.0 million	221210	500 Employees	2
4953	$10.0 million	562920; 562211; 562212; 562213; 562219	$10.5 million	2
6141	$5.0 million	522220; 522291	$6.0 million	1
		522120; 522210	$150 million in assets	
6211	$5.0 million	523110; 523120; 523910; 523999	$6.0 million	1
6719	$5.0 million	551112	$6.0 million	1
Total				**13**

Source: U.S. EPA Analysis, 2004.

Table D1A2-3: NAICS thresholds Are Less than SIC Thresholds Fewer Firms May Be Classified as Small

SIC Code	SIC Code Threshold	NAICS Code(s)	NAICS Code Threshold	Number of Potentially Affected Firms
2819	1,000 Employees	325998	500 Employees	1
3312	1,000 Employees	324199	500 Employees	11
3315	1,000 Employees	332618	500 Employees	1
3353	750 Employees	332996	500 Employees	1
3728	1,000 Employees	332912; 333995; 333996	500 Employees	1
5171	100 Employees	454311	$10.5 million	2
		454312	$6.0 million	
Total				**17**

Source: U.S. EPA Analysis, 2004.

D1A2-3 RESULTS

During the final step of this comparison, EPA analyzed firms for which the SIC code-based business size threshold differs from the NAICS code-based threshold. For all but one firm, this analysis found that the SIC-based and NAICS-based business size determinations were unambiguously the same: based on the firm's employment, revenue, or electric output, no previously determined small business is large, and no previously determined large businesses is small, under the NAICS-based threshold. However, for one firm, in SIC Code 3312, EPA's initial finding of potential change in business size classification was ambiguous because the SIC Code in which the firm is classified, mapped to more than one NAICS code, and the NAICS code-based size thresholds were not the same: for one of the corresponding NAICS codes (324199), the firm's business size determination would change while for the other NAICS code (331111), the determination would not change (see also Table D1A2-1). For this firm, EPA used information from the Dun and Bradstreet business database to identify the firm's NAICS code as 331111, which has the same small business threshold of 1,000 employees as SIC code 3312. Therefore, this analysis found no difference in small entity determinations, and therefore no change in small entity impacts, as a result of using NAICS-based size standards instead of SIC-based size standards, for the small business determination.

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Chapter D2: 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 UMRA section 202, 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, UMRA section 205 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 is proposing three options that define which existing facilities would be subject to the national categorical requirements under the proposed rule: the "50 MGD for All Waterbodies" option (the "50 MGD All"option); the "200 MGD for All Waterbodies" option (the "200 MGD All" option); and the "100 MGD for Certain Waterbodies" option (the "100 MGD CWB" option). These options all require the same reduction in impingement and entrainment (I&E), and differ only by applicability criteria defined on the basis of design intake flow (DIF) and waterbody type. As a result, the number of facilities that would be required to meet the national categorical requirements varies among the three options. EPA is also proposing section 316(b) requirements for new offshore oil and gas extraction facilities (also abbreviated as "new OOGE facilities") in Phase III. These proposed requirements are based on a 2 MGD DIF applicability threshold and would apply to an estimated 124 new offshore oil and gas extraction facilities.

- ***50 MGD for All Waterbodies option for existing facilities and proposed option for new offshore oil and gas extraction facilities:*** EPA estimates the total annualized after-tax costs of compliance for this option to be $44.8 million (2003$). All of these direct facility costs are incurred by the private sector (including 136 manufacturing facilities and 124 new offshore oil and gas extraction facilities). No facility owned by State and local governments would be subject to the national categorical requirements under this proposed option. Additionally, State and local permitting authorities are estimated to incur $0.5 million annually to administer this option, including labor costs to write permits and to conduct compliance monitoring and enforcement activities. EPA estimates that the highest undiscounted after-tax cost incurred by the private sector in any one year is approximately $280 million in 2011.

- ***200 MGD for All Waterbodies option for existing facilities and proposed option for new offshore oil and gas extraction facilities:*** EPA estimates the total annualized after-tax costs of compliance for this option to be $21.4 million (2003$). All of these direct facility costs are incurred by the private sector (including 25 manufacturing facilities and 124 new offshore oil and gas extraction facilities). No facility owned by State and local governments would be subject to the national categorical requirements under this proposed option. Additionally, State and local permitting authorities are estimated to incur $0.1 million annually to administer this option, including labor costs to write permits and to conduct compliance monitoring and enforcement activities. EPA estimates that the highest undiscounted after-tax cost incurred by the private sector in any one year is approximately $91 million in 2010.

- ***100 MGD for Certain Waterbodies option for existing facilities and proposed option for new offshore oil and gas extraction facilities:*** EPA estimates the total annualized after-tax costs of compliance for this option to be $17.4 million (2003$). All of these direct facility costs are incurred by the private sector (including 19 manufacturing facilities and 124 new offshore oil and gas extraction facilities). No facility owned by State and local governments would be subject to the national categorical requirements under this proposed option. Additionally, State and local permitting authorities are estimated to incur $0.2 million annually to administer this option, including labor costs to write permits and to conduct compliance monitoring and enforcement activities. EPA estimates that the highest undiscounted after-tax cost incurred by the private sector in any one year is approximately $236 million in 2011.

Given these findings, EPA has determined that this rule contains a Federal mandate that may result in expenditures of $100 million or more in any one year, for State, local, and Tribal governments, in the aggregate, or the private sector. Accordingly, under §202 of the UMRA, EPA has prepared a written statement, presented in the preamble to the proposed 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. In addition, the appendix to this chapter presents summary results for five other options evaluated for existing facilities (Option 1, Option 2, Option 3, Option 4, and Option 6).

D2-1 ANALYSIS OF IMPACTS ON GOVERNMENT ENTITIES

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

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

Both types of costs are discussed on the following pages.

D2-1.1 Compliance Costs for Government-Owned Facilities

The Electric Generating Industry is the only industry segment potentially subject to Phase III regulation with government-owned facilities. No facilities in the Manufacturers or new offshore oil and gas extraction facility segment are owned by a government. EPA has determined that no government-owned facility has a DIF that exceeds 50 MGD (the minimum applicability threshold of the proposed options). Therefore, no government-owned facility would incur compliance costs under any of the proposed options.

D2-1.2 Administrative Costs for Existing Facilities

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 would incur three types of costs associated with implementing the requirements of the proposed rule: (1) start-up activities, (2) permitting activities associated with the initial NPDES permit containing the new section 316(b) requirements and subsequent permit renewals, and (3) annual activities.[1] EPA estimates that the total costs for these activities under the three proposed options would be between $0.1 million and $0.5 million, annualized over 30 years at a 7% discount rate. Table D2-1 presents the estimated annualized costs of the three major administrative activities for each of the proposed options.

Table D2-1: Annualized Government Administrative Costs (in millions, 2003$)

Activity	50 MGD All Option	200 MGD All Option	100 MGD CWB Option
Start-Up Activities	$0.01	$0.01	$0.01
Permitting Activities	$0.39	$0.08	$0.11
Annual Activities	$0.15	$0.03	$0.03
Total	**$0.55**	**$0.12**	**$0.15**

Source: U.S. EPA Analysis, 2004.

Based on the specific permitting requirements of each facility (see *Chapter B1: Summary of Cost Categories and Key Analysis Elements for Existing Facilities*), EPA calculated total government costs of implementing the proposed 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 governments under the three proposed options is approximately $2.0 million in 2011 (50 MGD All option). EPA notes that the annualized cost of administrative activities depends on when they are incurred. If facilities reach compliance later than assumed in this analysis, permitting authorities' administrative activities would also occur in later years. As a result, the annualized costs of the rule to permitting authorities would be lower because administrative costs incurred in later years have lower present values.

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 proposed rule. Start-up activities include reading and understanding the rule, mobilization and planning of the resources required to address the rule's requirements, and training technical staff on how to review materials submitted by facilities and make determinations on the proposed Phase III 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 D2-2 shows the total start-up costs EPA estimated permitting authorities to incur. Each permitting authority is estimated to incur start-up costs of $4,000 as a result of the proposed rule. EPA assumes that the initial start-up activities would be incurred by all permitting authorities at the beginning of 2007, the year the Phase III requirements would take effect.

[1] The costs associated with implementing Phase III requirements are documented in EPA's Information Collection Request (U.S. EPA, 2003).

Table D2-2: Government Costs of Start-Up Activities (per Permitting Authority; 2003$)

Start-Up Activity	Start-Up Costs
Read and Understand Rule	$977
Mobilization/Planning	$1,698
Training	$1,219
Other Direct Costs	$50
Total	**$3,944**

Source: U.S. EPA, 2004.

b. Initial Post-Promulgation Permitting and Repermitting Activities

The permitting authorities would be required to implement the proposed Phase III requirements 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 each complying facility's first permit containing the new section 316(b) requirements would be issued between 2010 and 2014.[2] Repermitting activities would take place every five years after initial permitting.

The proposed 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 D2-3 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 would provide.

Two of the permitting activities presented within Table D2-3 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 would 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 proposed rule. EPA estimates that under the proposed rule, 50 facilities would apply for a site-specific determination.[3]

[2] For an explanation of how the compliance years were assigned to facilities subject to Phase III regulation, see Chapter B1.

[3] EPA is not including this site-specific determination as a direct cost for complying facilities because this is an optional activity that the facility would 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 proposed 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 D2-3: Government Permitting Costs (per Permit; 2003$)

Activity	First Post-Promulgation Permit	Repermitting
Review Source Water Physical Data	$290	$113
Review CWIS Data	$871	$259
Review CWS Operation Narrative	$871	$259
Review Proposal for Collection of Information for Comprehensive Demonstration Study	$1,302	$407
Review Source Water Body Flow Information	$290	$113
Review Design and Construction Technology Plan	$1,443	$410
Review Impingement Mortality Monitoring Results	$4,279	$1,284
Review Entrainment Characterization Monitoring Results	$4,279	$1,284
Review Baseline Characterization Monitoring Results and Study Findings	$12,678	$3,819
Review Pilot Study for New Impingement & Entrainment Technology	$1,302	$407
Review Restoration Measures[a]	$2,299	$690
Review Technology Installation and Operation Plan & Verification Monitoring Plan	$1,047	$311
Determine Monitoring Frequency	$290	$113
Determine Record Keeping and Reporting Frequency	$290	$113
Considering Public Comments	$1,302	$407
Issuing Permit	$265	$64
Permit Record Keeping	$130	$24
Other Direct Costs	$310	$310
Total Cost (without site specific determination)[b]	**$33,541**	**$10,387**
Review Information to Support Site-Specific Determination of BTA	$45,980	$13,794
Establish Requirements for Site-Specific Technology	$1,162	$322
Site-Specific Costs[c]	**$47,142**	**$14,116**
Total Cost (with site specific determination)[b]	**$80,683**	**$24,503**

[a] Assumed to apply to only 10% of facilities. Only 10% of the per permit costs of $22,990 and $6,897 is accounted for in this framework.
[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, 2004.

As shown in Table D2-3, initial post-promulgation permits that do not require a site-specific determination of BTA are expected to impose an average per permit cost of $34,000 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 are estimated to increase by $47,000, resulting in total per permit costs of approximately $81,000.

The State administrative cost for a permit renewal that does not include a site-specific determination is $10,000. For facilities that conduct a site-specific determination, the cost per permit imposed on the permitting authority increases by $14,000, resulting in an average repermitting cost of almost $25,000.

Permitting authorities also incur costs 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 $800 per permit. Table D2-4 lists the components of verification study review.

Table D2-4: Government Costs of Verification Study Review (per Permit; 2003$)

Activity	Post-Promulgation Permit Costs
Review of Verification Studies	$227
Permit Modification Due to Unfavorable Results	$517
Recordkeeping	$24
Other Direct Costs	$10
Total	**$778**

Source: U.S. EPA, 2004.

Finally, State governments may incur costs associated with alternative regulatory requirements. States may adopt in their NPDES programs, alternative regulatory requirements to reduce impingement mortality and entrainment within a watershed. If these States demonstrate to the Administrator that the reductions are comparable to what would otherwise be achieved under rule, the Administrator would approve these alternative regulatory requirements. For the final Phase II rule, EPA estimated that 10 regulatory permitting authorities would incur costs associated with alternative regulatory requirements. For this analysis, EPA assumed that those States interested in adopting alternative regulatory requirements would have done so under the Phase II rule. As a result, EPA assumes that these States would incur no additional costs for establishing alternative regulatory requirements under this proposed rule. Table D2-5 reports the cost of each component of establishing alternative regulatory requirements.

Table D2-5: Government Costs of Alternative Regulatory Requirements (per Permitting Authority; 2003$)

Activity	Post-Promulgation Permit Costs
Document Alternative Regulatory Requirements	$1,360
Document Environmental Conditions within Watershed	$1,813
Include Supporting Historical Studies, Calculations, and Analyses	$3,542
Submit Documentation	$97
Recordkeeping	$138
Other Direct Costs	$100
Total[a]	**$7,049**

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

Source: U.S. EPA, 2004.

c. Annual activities

In addition to the start-up and permitting activities discussed above, permitting authorities would have to perform certain annual activities to ensure the continued implementation of the requirements of the proposed rule. These annual activities include reviewing biannual status reports, tracking compliance, making determinations on monitoring frequency reduction, and record keeping.

Table D2-6 outlines the annual activities necessary for each permit, along with their estimated costs. These costs begin with the issuance of the first permit following promulgation of the rule. A total cost of approximately $1,500 is estimated for each permit per year.

Table D2-6: Government Costs for Annual Activities (per Permit; 2003$)

Annual Activity	Annual Costs
Review of Biannual Status Report[a]	$340
Compliance Tracking	$581
Determination of Monitoring Frequency Reduction	$453
Record Keeping	$138
Other Direct Costs	$30
Total[b]	**$1,541**

[a] This is a cost that is incurred once every two years. Therefore, only half of the total review cost of $680 is accounted for in this annual framework.

[b] Individual numbers may not sum to total due to independent rounding.

Source: U.S. EPA, 2004.

The Federal government is likely to incur costs for reviewing and validating proper implementation of the section 316(b) elements of States' NPDES permits that are issued after promulgation of the rule. Table D2-7 outlines the annual activities associated with reviewing a permit issued after promulgation of the rule, along with the estimated cost of each activity. EPA estimates a cost of approximately $2,300 per permit for post-promulgation review. Costs incurred by the Federal government are not part of the UMRA analysis but are part of the social cost analysis presented in Chapter E1 of this EA.

Table D2-7: Federal Government Permit Program Oversight Activities (per Permit; 2003$)

Annual Activity	Post-Promulgation Permit Costs
Review Source Water Physical Data	$145
Review CWIS Data	$113
Review CWS Operation Narrative	$113
Review Proposal for Collection of Information for Comprehensive Demonstration Study	$113
Review Source Water Body Flow Information	$113
Review Design and Construction Technology Plan	$145
Review Impingement Mortality Study and/or Entrainment Characterization Study	$340
Review Pilot Study for New Impingement & Entrainment Technology	$113
Review Restoration Measures[a]	$34
Review Technology Installation and Operation Plan & Verification Monitoring Plan	$145
Review the Monitoring Frequency	$113
Permit Record Keeping	$130
Other Direct Costs	$50
Total Cost (without site specific determination)[b]	**$1,699**
Review Information to Support Site-Specific Determination of BTA	$680
Review the Established Requirements for Site-Specific Technology	$145
Site-Specific Costs[c]	**$825**
Total Cost (with site specific determination)[b]	**$2,494**

[a] Assumed to apply to only 10% of facilities. Only 10% of the per permit cost of $340 is accounted for in this framework.
[b] Applies only to certain facilities, according to site specific determination of BTA Compliance Schedule.
[c] Individual numbers may not add up to total due to independent rounding.

Source: U.S. EPA, 2004.

D2-1.3 Administrative Costs for New Offshore Oil and Gas Extraction Facilities

For new facilities in the offshore oil and gas extraction industry, NPDES permitting is consolidated under General Permits, which are administered by EPA Regional offices. No States are involved in these permitting activities. Thus, unlike for existing facilities, States would incur no costs for new facility permitting. Three EPA Regions (Region 6, Region 4, and Region 10) are expected to be the only entities responsible for permitting. Because States are not involved in the section 316(b) permitting for new offshore oil and gas extraction facilities, the Federal government would incur no costs for State oversight, which again differs from the existing facilities case. The affected EPA Regions would incur three types of costs for implementing the proposed rule: (1) start-up activities, (2) activities associated with the initial General Permit containing the new section 316(b) requirements and subsequent permit renewals, and (3) annual activities. These activities and their timing assumptions are discussed below. The timing of these costs and how they are discounted and annualized are documented in the Oil and Gas 316(b) Compliance Cost Model (see DCN 7-4018). For more information on the methods used for discounting and cost annualization, see *Chapter C1: Summary of Cost Categories and Key Analysis Elements for New Offshore Oil and Gas Extraction Facilities*.

It should be noted that costs incurred by the Federal government are not part of the UMRA analysis, but are part of the social cost analysis presented in *Chapter E1: Summary of Social Costs* and *Chapter C3: Economic Impact Analysis for the Offshore Oil and Gas Extraction Industry* of this EA.

a. Start-Up Activities

Start-up activities are not considered incremental to existing Regional permitting activities (U.S. EPA, 2004).

b. Initial Post-Promulgation Permitting and Repermitting Activities

Initial permitting and repermitting activities relate to the review of data collected for the regional studies and the individual data submitted by facilities that plan to be permitted (or re-permitted) under the General Permits in the three EPA Regions. Tables D2-8 and D2-9 present the individual activities and their costs for Regions 4, 6, and 10. These costs are on a per facility basis, i.e., the regions incur these costs for each facility that is permitted under their general permits (see DCN 7-4018, which illustrates how these costs are aggregated and assigned to the regions).

Table D2-8 presents the permit issuance activities and their related costs. The per facility initial permitting cost of approximately $12,000 would be incurred in 2012 for facilities brought on-line or launched between 2007 and 2012 (Region 6) and in 2014 for facilities brought on-line or launched between 2007 and 2014 (Region 4 and 10). In later years, these costs are assumed to be incurred in the year of compliance of each new facility. The burden of repermitting is expected to be smaller than the burden of initial permitting, approximately $3,200 per facility, because the permitting authority is already familiar with the facility's case and the type of information the facility would provide. Repermitting costs are incurred in 5-year intervals after the initial post-promulgation permit.

Table D2-8: Federal Government Costs for Permit Issuance Activities (Per Facility Permitted under General Permits; 2003$)

Activity	First Post-Promulgation Permit	Repermitting
Review Source Water Physical Data	$290	$113
Review CWIS Data	$871	$259
Review Source Water Body Flow Information	$290	$113
Review CWIS Velocity Information	$1,302	$407
Review Design and Construction Technology Plan	$1,443	$410
Review Regional Monitoring Study Design and Sampling Plans	$1,443	n/a
Review Regional Monitoring Study	$2,778	n/a
Review Source Water Baseline Biological Characterization Study	$1,302	$849
Determine Monitoring Frequency	$290	$113
Determine Record Keeping and Reporting Frequency	$290	$113
Consider Public Comments	$1,302	$407
Issue Permit	$265	$64
Permit Record Keeping	$130	$24
ODCs Lump Sum	$310	$310
Total[a]	**$12,309**	**$3,183**

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

Source: U.S. EPA, 2004.

c. Annual activities

Annual costs are associated with the activities that must be undertaken by the regions each year for each active facility operating under the applicable General Permit. These activities also include a one-time cost for determining monitoring frequency reduction. This cost is assigned only to facilities operating at the time the decision about monitoring frequency reduction is made (assumed to occur at the end of the initial two years of monitoring, which is 2013 for the Region 6 permit and 2015 for the Region 4 and Region 10 permits). Table D2-9 outlines these activities and their associated costs.

Table D2-9: Federal Government Costs for Annual Activities (Per Facility Permitted under General Permits; 2003$)

Activity	Annual Costs
Review of Yearly Status Report	$680
Compliance Tracking	$581
Determination on Monitoring Frequency Reduction[a]	$0
Record Keeping	$138
ODCs Lump Sum	$30
Total[b]	**$1,428**

[a] One-time cost of $453 incurred only by those facilities operating in 2013 (Region 6) or 2014 (Regions 4 and 10).
[b] Individual numbers may not sum to total due to independent rounding.

Source: U.S. EPA, 2004.

D2-1.4 Impacts on Small Governments

EPA's analysis also considered whether the proposed rule may significantly or uniquely affect small governments (i.e., governments with a population of less than 50,000). As described earlier, the Electric Generating Industry is the only industry segment with government-owned facilities; governments own no facilities in either the Manufacturers or new offshore oil and gas extraction facility segments. No government-owned facility exceeds the 50 MGD DIF applicability threshold (the smallest DIF applicability threshold of the three proposed options). Therefore, no government-owned facility would incur compliance costs under any of the three proposed options. As no facilities owned by small governments are subject to national requirements under the proposed options, EPA has determined that the three proposed options would contain no regulatory requirements that might significantly or uniquely affect small governments.

D2-2 COMPLIANCE COSTS FOR THE PRIVATE SECTOR

The only compliance costs incurred by the private sector result from facilities complying with the proposed options. These options all require the same reduction in impingement and entrainment (I&E), and differ only by applicability threshold, which is based on the facilities' design intake flow and waterbody type. These direct facility costs already include the cost to facilities of obtaining their NPDES permits. The methodology for determining compliance costs for Phase III existing facilities is presented in *Chapter B1: Summary of Cost Categories and Key Analysis Elements for Existing Facilities* of this EA; the methodology for Phase III new offshore oil and gas extraction facilities is presented in Chapter C1: *Summary of Cost Categories and Key Analysis Elements for New Offshore Oil and Gas Extraction Facilities*. EPA identified all facilities subject to national categorical requirements under the three proposed options to be owned by a private entity.

Private sector costs for the proposed option for Phase III new facilities and for the three proposed options for Phase III existing facilities are as follows (discounted at a 7% rate):

- Under the ***50 MGD for All Waterbodies option for existing facilities and the proposed option for new offshore oil and gas extraction facilities***, 260 facilities are estimated to incur annualized compliance costs of $44.8 million and a maximum one year cost of $280.3 million in 2011.

- Under the ***200 MGD for All Waterbodies option for existing facilities and the proposed option for new offshore oil and gas extraction facilities***, 149 privately-owned facilities are estimated to incur annualized compliance costs of $21.4 million and a maximum one year cost, in 2010, of $90.8 million.

- Under the ***100 MGD for Certain Waterbodies option for existing facilities and the proposed option for new offshore oil and gas extraction facilities***, 143 privately-owned facilities are estimated to incur annualized compliance costs of $17.4 million and a maximum one year cost, in 2011, of $235.6 million.

D2-3 SUMMARY OF UMRA ANALYSIS

EPA estimates that the proposed rule would 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 D2-10 summarizes the after-tax compliance costs for facilities, and the costs to implement the rule for permitting authorities, under the proposed options.

Table D2-10: Summary of UMRA Costs (in millions, 2003$)

Sector	Total Annualized Cost			Maximum One-Year Cost		
	Facility Compliance Costs	Government Implementation Costs	Total	Facility Compliance Costs	Government Implementation Costs	Total
50 MGD for All Waterbodies Option for Existing Facilities / Proposed Option for New OOGE Facilities						
Government Sector (excl. Federal)	$0.0	$0.5	$0.5	$0.0	$2.0	$2.0
Private Sector	$44.8	n/a	$44.8	$280.3	n/a	$280.3
200 MGD for All Waterbodies Option for Existing Facilities / Proposed Option for New OOGE Facilities						
Government Sector (excl. Federal)	$0.0	$0.1	$0.1	$0.0	$0.4	$0.4
Private Sector	$21.4	n/a	$21.4	$90.8	n/a	$90.8
100 MGD for Certain Waterbodies Option for Existing Facilities / Proposed Option for New OOGE Facilities						
Government Sector (excl. Federal)	$0.0	$0.2	$0.2	$0.0	$0.8	$0.8
Private Sector	$17.4	n/a	$17.4	$235.6	n/a	$235.6

Source: U.S. EPA Analysis, 2004.

Costs for new offshore oil and gas extraction facilities and the three proposed options for Phase III existing facilities are as follows:

- The ***50 MGD for All Waterbodies option for existing facilities and the proposed option for new offshore oil and gas extraction facilities*** would impose annual costs of $0.5 million on State and local governments (in implementation costs only), and $44.8 million on the private sector. Maximum one year costs under this option are estimated to be approximately $2.0 million for government entities, and $280.3 million for the private sector. Both of these maximum annual cost values are estimated to occur in 2011.

- The ***200 MGD for All Waterbodies option for existing facilities and the proposed option for new offshore oil and gas extraction facilities*** would impose annual costs of $0.1 million on State and local governments (in implementation costs only), and $21.4 million on the private sector. Maximum one year costs under this option are approximately $0.4 million for government entities in 2011, and $90.8 million for the private sector in 2010.

- The ***100 MGD for Certain Waterbodies option for existing facilities and the proposed option for new offshore oil and gas extraction facilities*** would impose annual costs of $0.2 million on State and local governments (in implementation costs only), and $17.4 million on the private sector. Maximum one year costs under this option are approximately $0.8 million for government entities and $235.6 million for the private sector, both of which are estimated to occur in 2011.

REFERENCES

U.S. Environmental Protection Agency (U.S. EPA). 2004. *Information Collection Request (ICR) for Cooling Water Intake Structures Phase III Proposed Rule*. ICR Number 2169.01. October 2004.

Appendix to Chapter D2

This appendix presents the results of the UMRA analysis for the other five options considered for Phase III existing facilities, combined with the proposed option for new offshore oil and gas extraction facilities. For all options, results only include those Phase III existing facilities that are (1) non-baseline closures and (2) subject to national categorical requirements under the option. See the main body of this chapter for a description of data sources and methodologies used in these analyses.

In Table D2A-1 below, the other evaluated options for Phase III existing facilities, combined with the proposed option for new offshore oil and gas extraction facilities, are presented in order of increasing stringency and/or applicability (e.g., the largest number of facilities would be subject to the national requirements under Option 6, compared to any of the other evaluated options).

Table D2A-1: Summary of UMRA Costs for Other Evaluated Options (in millions, 2003$)

Sector	Total Annualized Cost			Maximum One-Year Cost		
	Facility Compliance Costs	Government Implementation Costs	Total	Facility Compliance Costs	Government Implementation Costs	Total
Option 3 for Existing Facilities / Proposed Option for New OOGE Facilities						
Government Sector (excl. Federal)	$1.0	$0.9	$1.9	$1.8	$4.5	$6.3
Private Sector	$61.9	n/a	$61.9	$712.2	n/a	$712.2
Option 4 for Existing Facilities / Proposed Option for New OOGE Facilities						
Government Sector (excl. Federal)	$0.8	$0.8	$1.6	$1.7	$4.6	$6.4
Private Sector	$66.0	n/a	$66.0	$722.9	n/a	$722.9
Option 2 for Existing Facilities / Proposed Option for New OOGE Facilities						
Government Sector (excl. Federal)	$1.4	$1.0	$2.4	$2.4	$5.6	$7.9
Private Sector	$70.5	n/a	$70.5	$730.7	n/a	$730.7
Option 1 for Existing Facilities / Proposed Option for New OOGE Facilities						
Government Sector (excl. Federal)	$1.5	$1.1	$2.6	$2.4	$5.6	$8.1
Private Sector	$72.3	n/a	$72.3	$737.2	n/a	$737.2
Option 6 for Existing Facilities / Proposed Option for New OOGE Facilities						
Government Sector (excl. Federal)	$1.8	$1.7	$3.5	$2.8	$7.6	$10.5
Private Sector	$91.7	n/a	$91.7	$922.3	n/a	$922.3

Source: U.S. EPA Analysis, 2004.

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Chapter D3: Other Administrative Requirements

INTRODUCTION

This chapter presents several other analyses conducted in developing this proposed rule. These analyses address the requirements of Executive Orders and Acts applicable to Phase III regulation.

CHAPTER CONTENTS

D3-1 EXECUTIVE ORDER 12866: REGULATORY PLANNING AND REVIEW

Under Executive Order 12866 (58 FR 51735, October 4, 1993), the Agency must determine whether the regulatory action is "significant" and therefore subject to OMB review and the requirements of the Executive Order. The order defines a "significant regulatory action" as one that is likely to result in a rule that may:

- have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or Tribal governments or communities; or
- create a serious inconsistency or otherwise interfere with an action taken or planned by another agency; or
- materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or
- raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

Pursuant to the terms of Executive Order 12866, EPA determined that this proposed rule is a "significant regulatory action." As such, this action was submitted to OMB for review. Changes made in response to OMB suggestions or recommendations are documented in the public record.

D3-2 PAPERWORK REDUCTION ACT OF 1995

The Paperwork Reduction Act of 1995 (PRA) (superseding the PRA of 1980) is implemented by the Office of Management and Budget (OMB) and requires that agencies submit a supporting statement to OMB for any information collection that solicits the same data from more than nine parties. The PRA seeks to ensure that Federal agencies balance their need to collect information with the paperwork burden imposed on the public by the collection.

The definition of "information collection" includes activities required by regulations, such as permit development, monitoring, record keeping, and reporting. The term "burden" refers to the "time, effort, or financial resources" the public expends to provide information to or for a Federal agency, or to otherwise fulfill statutory or regulatory requirements. PRA paperwork burden is measured in terms of annual time and financial resources the public devotes to meet one-time and recurring information requests (44 U.S.C. 3502(2); 5 C.F.R. 1320.3(b)).

Information collection activities may include:

- reviewing instructions;
- using technology to collect, process, and disclose information;
- adjusting existing practices to comply with requirements;
- searching data sources;
- completing and reviewing the response; and
- transmitting or disclosing information.

Agencies must provide information to OMB on the parties affected, the annual reporting burden, the annualized cost of responding to the information collection, and whether the request significantly impacts a substantial number of small entities. An agency may not conduct or sponsor, and a person is not required to respond to, an information collection unless it displays a currently valid OMB control number.

EPA's estimate of the information collection requirements imposed by the proposed Phase III regulation are documented in the Information Collection Request (ICR) which accompanies this regulation (U.S. EPA, 2004).

D3-3 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 proposed rule does not have federalism implications. It would 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. Rather, this proposed rule would result in minimal administrative costs on States that have an authorized NPDES program. EPA expects the following annual burden for States to collectively administer one of the three proposed options:

- 50 MGD for All Waterbodies option: 16,972 hours with a cost of $754,804 ($747,981 in labor costs and $6,823 in non-labor costs);
- 200 MGD for All Waterbodies option: 4,677 hours with a cost of $201,092 ($198,932 in labor costs and $2,160 in non-labor costs);
- 100 MGD for Certain Waterbodies option: 6,528 hours with a cost of $286,597 ($284,624 in labor costs and $1,973 in non-labor costs).

It is noted that States do not incur any burden hours and costs to administer the proposed rule for the new offshore oil and gas extraction facilities because the EPA Regions administer their permits; these facilities are therefore outside the jurisdiction of the States. In addition, EPA has identified zero Phase III existing facilities that are owned by Federal, State or local government entities therefore the annual impacts on these facilities is zero.

The proposed national cooling water intake structure requirements would be implemented through permits issued under the NPDES program. Forty-five States and one territory 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 this proposed rule to have substantial direct effects on either authorized or nonauthorized States or on local governments because it would not change how EPA and the States and local governments interact or their respective authority or responsibilities for implementing the NPDES program. This rule establishes national requirements for Phase III facilities with cooling water intake structures. NPDES-authorized States that currently do not comply with the proposed 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) rulemaking and this proposed rule:

- During the development of the proposed section 316(b) rule for new facilities (Phase I), EPA conducted several outreach activities through which State and local officials were informed about the section 316(b) 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). 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. In some cases these comments have informed the development of the Phase III rulemaking effort.

- On May 23, 2001, EPA held a day-long forum to discuss specific issues associated with the development of regulations under section 316(b). At the meeting, 17 experts from industry, public interest groups, States, and academia reviewed and discussed the Agency's preliminary data on cooling water intake structure technologies that are in place at existing facilities and the costs associated with the use of available technologies for reducing impingement and entrainment. Over 120 people attended the meeting.

In the spirit of this Executive Order and consistent with EPA policy to promote communications between EPA and State and local governments, the preamble to this proposed rule specifically solicits comment from State and local officials.

D3-4 EXECUTIVE ORDER 13175: CONSULTATION AND COORDINATION WITH INDIAN TRIBAL GOVERNMENTS

Executive Order 13175 (65 FR 67249, November 6, 2000) requires EPA to develop an accountable process to ensure "meaningful and timely input by tribal officials in the development of regulatory policies that have tribal implications." "Policies that have tribal implications" is defined in the Executive Order to include regulations that have "substantial direct effects on one or more Indian Tribes, on the relationship between the Federal government and the Indian Tribes, or on the distribution of power and responsibilities between the Federal government and Indian Tribes." This proposed rule does not have tribal implications. It would 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 Phase III regulation is owned by tribal governments. This proposed rule does not affect Tribes in any way in the foreseeable future. Accordingly, the requirements of Executive Order 13175 do not apply to this rule.

D3-5 EXECUTIVE ORDER 13045: PROTECTION OF CHILDREN FROM ENVIRONMENTAL HEALTH RISKS AND SAFETY RISKS

Executive Order 13045 (62 FR 19885, April 23, 1997) applies to any rule that (1) is determined to be "economically significant" as defined under Executive Order 12866 and (2) concerns an environmental health or safety risk that EPA has reason to believe might have a disproportionate effect on children. If the regulatory action meets both criteria, the Agency must evaluate the environmental health and safety effects of the planned rule on children and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by the Agency. This proposed rule is a 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.

D3-6 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 proposed 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 proposed rule does not contain any compliance requirements that would:

- 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 this proposed rule. Regulation of Electric Generators, through increases in the cost of generating electricity and shifts in the types of generators employed, 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. Regulation of new offshore oil and gas facilities might affect (1) the production of oil and gas, (2) energy prices, and (3) the dependence on foreign supplies of energy. While facilities in the Manufacturing industry segments generate electricity, their contribution to the overall supply of electricity is insignificant (less than 0.02%); therefore, compliance with the 316(b) Phase III regulation by this industry segment would not perceptibly affect the supply, distribution, or use of energy.

Potential energy effects associated with the regulation of existing Electric Generators and new offshore oil and gas extraction facilities are described in the following two subsections.

D3-6.1 Existing Electric Generators

The three proposed options for Electric Generators have design intake flow (DIF) applicability thresholds for national categorical requirements of 50 MGD or greater, 100 MGD or greater, and 200 MGD or greater. Since Electric Generators with a DIF of 50 MGD or greater were covered by the final Phase II rule, no Phase III

Generator would be subject to the national requirements under the three proposed options; therefore there would be no impacts on any measures of energy supply, distribution, or use under the proposed rule.

To assess potential energy effect of alternative evaluated options for Electric Generators, EPA used the results from its electricity market model analysis (see the Appendix to *Chapter B5: Economic Impact Analysis for Electric Generators*). EPA compared the post-compliance scenario (after the implementation of Phase III compliance requirements) with Base Case 2 (including Phase II compliance costs but excluding Phase III compliance costs). This comparison allows EPA to identify the incremental market-level effects of Phase III regulation, beyond the effects of Phase II regulation. It should be noted that this analysis was only conducted for Option 6, the most inclusive option with the highest regulatory costs and potential for energy effects. Therefore, the potential energy effects of all other options evaluated by EPA would be lower.

❖ ***Production of coal***

EPA estimates that Option 6 would decrease the annual use of coal for electricity generation by 53.8 trillion Btu (TBtu), or 0.25%. This reduction converts to 2.66 million tons of coal per year or 7,286 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 Option 6 would 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 Option 6 would not reduce electricity production in excess of 1 billion kilowatt hours per day.

❖ ***Installed capacity***

None of the evaluated options contain requirements that would 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 up to nine weeks of steam electric generators subject to Phase III regulation. EPA estimates that under Option 6 approximately four facilities, accounting for 145 megawatts (MW) of generating capacity, would experience such downtimes. However, EPA's analyses indicate that these downtimes would not have a significant adverse effect on the supply, distribution, or use of energy (see the Appendix to *Chapter B5: Economic Impact Analysis for Electric Generators*). In addition, EPA estimates that Option 6 would lead to only 173 MW in incremental permanent capacity closures, well below the 500 MW impact threshold.

❖ ***Energy prices***

Option 6 would not significantly affect energy prices in either the long run or the short run. EPA estimates that, in the long run, energy prices would rise by less than 1% in all but one 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 1.1% in 2010 and 5.2% in 2013. No other region would experience energy price increases of more than 0.2% as a result of Phase III regulation.

❖ ***Dependence on foreign supplies of energy***

EPA's electricity market analysis did not allow for an explicit consideration of effects on foreign imports of energy. However, Electric 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 estimated to be small. EPA therefore concludes that Option 6 would not significantly increase dependence on foreign supplies of energy.

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

D3-6.2 New Offshore Oil and Gas Extraction Facilities

This rule applies only to new offshore oil and gas extraction facilities and not existing ones. Hence the rule would have no impact on existing production of oil and gas, energy prices, installed capacity, nor would it significantly increase dependence on foreign supplies of energy. EPA's analysis identified no barriers to entry or energy effects. EPA therefore concludes that the proposed rule would not significantly affect new offshore oil and gas production, energy prices, or dependence on foreign supplies of energy.

Based on these analyses for potentially regulated existing and new facilities, EPA concludes that this proposed rule would have minimal energy effects at a national and regional level. As a result, EPA did not prepare a Statement of Energy Effects.

D3-7 National Technology Transfer and Advancement Act of 1995

Section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) of 1995, Pub L. No. 104-113, Sec. 12(d) directs EPA to use voluntary consensus standards in its regulatory activities unless doing so would be inconsistent with applicable law or otherwise impractical. Voluntary consensus standards are technical standards (e.g., materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by voluntary consensus standard bodies. The NTTAA directs EPA to provide Congress, through the Office of Management and Budget (OMB), explanations when the Agency decides not to use available and applicable voluntary consensus standards.

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

D3-8 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 proposed rule requires that the location, design, construction, and capacity of cooling water intake structures (CWIS) at Phase III facilities reflect the best technology available for minimizing adverse environmental impact. For several reasons, EPA does not expect that this proposed rule would have an exclusionary effect, deny persons the benefits of the participation in a program, or subject persons to discrimination because of their race, color, or national origin. In fact, because EPA expects that this proposed rule would help to preserve the health of aquatic ecosystems located in reasonable proximity to Phase III facilities, it believes that all populations, including minority and low-income populations, would benefit from improved environmental conditions as a result of this rule.

D3-9 Executive Order 13158: Marine Protected Areas

Executive Order 13158 (65 FR 34909, May 31, 2000) requires EPA to "expeditiously propose new science-based regulations, as necessary, to ensure appropriate levels of protection for the marine environment." EPA may take action to enhance or expand protection of existing marine protected areas and to establish or recommend, as appropriate, new marine protected areas. The purpose of the Executive Order is to protect the significant natural and cultural resources within the marine environment, which means "those areas of coastal and ocean waters, the Great Lakes and their connecting waters, and submerged lands thereunder, over which the United States exercises jurisdiction, consistent with international law." EPA expects that the Proposed Section 316(b) Rule for Phase III Facilities would 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) rulemaking, 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, this proposed rule would not only help protect individual species but also the overall marine environment, thereby advancing the objective of Executive Order 13158 to protect marine areas.

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Chapter E1: Summary of Social Costs

CHAPTER CONTENTS

INTRODUCTION

This chapter presents EPA's estimates of the costs to society associated with the options evaluated for the proposed rule for Phase III facilities. The ***social costs*** of regulatory actions are the ***opportunity costs*** to society of employing scarce resources to reduce environmental damages. The social costs of regulation include both monetary and non-monetary outlays made by society. Monetary outlays include the resource costs of compliance, government administrative costs, and other adjustment costs, such as the cost of relocating displaced workers. Non-monetary outlays, some of which can be assigned monetary values, include losses in consumers' and producers' surplus in affected product markets, the adverse effects of involuntary unemployment, possible loss of time (e.g., delays in investment decisions), and possible adverse impacts on the rate of innovation.

EPA's estimates of social costs for the evaluated section 316(b) Phase III options include three components:

1. direct costs of complying with the regulation within each regulated industry segment,
2. cost to State governments in administering the regulation, and
3. cost to the Federal government in administering the regulation.

This chapter presents the social cost analysis for the three proposed options for existing facilities: the "50 MGD for All Waterbodies" option ("50 MGD All"), the "200 MGD for All Waterbodies" option ("200 MGD All"), and the "100 MGD for Certain Waterbodies" Option ("100 MGD CWB"). These options differ with regard to (1) their design intake flow (DIF) applicability thresholds: 50, 100, and 200 MGD, respectively; and (2) the type of waterbodies to which they would apply: the options with the 50 and 200 MGD applicability thresholds would apply to all waterbody types while the option with the 100 MGD applicability threshold would apply only to facilities withdrawing cooling water from certain waterbody types (i.e., an ocean, estuary, tidal river/stream or one of the Great Lakes). Facilities meeting these applicability criteria would be required to meet similar performance standards to those required in the final 316(b) Phase II rule, including a 80-95% reduction in impingement mortality and a 60-90% reduction in entrainment. Facilities not meeting these applicability criteria would continue to be subject to permit requirements based on the Director's Best Professional Judgment (BPJ). As a result, the number of facilities that would be required to meet the national requirements would vary among the three proposed options. Of the three options presented here, the 100 MGD for Certain Waterbodies Option would apply national categorical requirements to the smallest number of facilities, with the 200 MGD for All Waterbodies Option and 50 MGD for All Waterbodies Option applying to successively larger numbers of facilities.

This chapter also presents social costs for new offshore oil and gas extraction facilities (also abbreviated as "new OOGE facilities"). The proposed requirements for this industry segment are based on a 2 MGD DIF applicability threshold and would apply to an estimated 124 new offshore oil and gas extraction facilities.

E1-1 COSTS OF COMPLIANCE BY REGULATED INDUSTRY SEGMENT

The compliance costs used to estimate total social costs differ in their consideration of taxes from those in *Part B: Economic Analysis for Phase III Existing Facilities*, and *Part C: Economic Analysis for Phase III New Offshore Oil and Gas Extraction Facilities*, which were calculated for the purpose of estimating the private costs and impacts of the evaluated options. For the impact analyses, compliance costs are measured according to their effect on the financial performance of the regulated facilities and firms. The analyses therefore explicitly consider the tax deductibility of compliance outlays.[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.

EPA included no costs for facilities that were assessed as baseline closures or that are subject to permit specifications based on best professional judgement (BPJ), instead of the proposed rule's national categorical requirements. However, EPA's estimates do include compliance costs for facilities estimated to close because of the rule.[2] This approach may overstate the social costs of compliance, to the extent that the net economic loss to society in facility closures is less than the estimated cost to society of compliance.[3]

To assess the cost to society of complying with Phase III regulation, EPA estimated the costs to facilities for the labor, equipment, materials, and other economic resources needed to comply with each evaluated option. In this analysis, EPA assumed that the market prices for labor, equipment, materials, and other compliance resources represent the opportunity costs to society for use of those resources in regulatory compliance.

For the analysis of installation downtime in the Electric Generators and Manufacturers segment, EPA assumed that the cost of society is equal to the increase in production cost for providing the electricity or other replacement goods and services not provided by the facilities that incur downtime in reaching compliance with the 316(b) Phase III regulation. For both Electric Generators and Manufacturers, this cost is approximated as the lost revenue from installation downtime *less* the variable cost of producing the electricity or other goods and services not produced due to the installation downtime. Implicit in this assumption is that the variable production cost of replacing the electricity or other lost goods and services is essentially the same as the price received for the sale of the electricity or other goods and services not produced by the facilities incurring the installation downtime. For electricity, this assumption is consistent with the electricity market concept that the variable production cost of the last generating unit to be dispatched is approximately the same as the price received for the last unit of production. For the goods and services not produced by affected Manufacturers facilities, the assumption is likewise consistent with a competitive market model of increasing marginal production cost, such that the production cost of the "last" or highest cost goods and services produced and sold in any period is approximately equal to the price received for those goods and services in the market. For Manufacturers – which do not necessarily produce and sell goods in as orderly markets as electric generators and where, as a result, the cost of producing replacement goods and services may be less than selling price – this assumption may overstate the cost to society of installation downtime. Absent specific knowledge of the overall production cost structure of the affected industries, EPA adopted this conservative assumption for its analysis of the social cost of Phase III regulation.

EPA estimates that the offshore oil and gas extraction industry segment would not incur cost from installation downtime because only new offshore oil and gas extraction facilities would be regulated under this proposed rule. The potential disruption in ongoing business operation estimated for existing Manufacturers and Electric Generators is not relevant for new facilities.

Finally, EPA assumes in its social cost analysis that none of the evaluated options would affect the aggregate quantity of goods and services sold to consumers by producers in the affected industry segments. The resource costs of compliance therefore manifest only as a reduction in the total of ***producers' surplus*** and ***consumers'***

[1] Because government facilities and cooperatives are not subject to income taxes, their costs are not adjusted for taxes.

[2] To the extent such impacts occur under any of the options analyzed.

[3] Including costs for regulatory closures yields an estimate of social costs assuming that all facilities, except those assessed as baseline closures, would incur the costs of regulatory compliance and continue to operate post-regulation. Calculating costs as if all facilities continue operating will overstate social costs if the social cost of compliance is greater than the net economic loss to society from facility closure. Whether this result will hold depends, in part, on the difference between social and private discount rates, and the marginal cost to society to replace the lost production of goods and services in closing facilities.

surplus, with no change in the quantity of goods and services produced and consumed. In the impact analyses, specific assumptions are made about the distribution of this effect between producers and consumers (i.e., the impact analyses of all analyzed section 316(b) Phase III industry segments – Manufacturers, Electric Generators, and new offshore oil and gas extraction facilities – assume that all compliance costs are absorbed by complying businesses with no increase in prices to consumers). However, for the social cost analysis, the distribution of this effect between producers and consumers is irrelevant. Given the very small impact of the options on total costs within the industry segments, EPA believes the assumption of no effect on total quantity of goods and services produced and consumed is reasonable.

Table E1-1 below summarizes total direct facility costs for the proposed rule new offshore oil and gas extraction facilities combined with the three proposed options for existing facilities. As described in *Chapter B1: Summary of Cost Categories and Key Analysis Elements for Existing Facilities* and *Chapter C1: Summary of Cost Categories and Key Analysis Elements for New Offshore Oil and Gas Extraction Facilities*, costs were first tallied on an as-incurred, year-by-year basis over the total time period of analysis, considering the latest year in which any affected facility is assumed to reach compliance (2014 for existing facilities, 2026 for new offshore oil and gas extraction facilities) and for a period of 30 years in which facilities are assumed to continue compliance, for the purposes of the social cost analysis. Thus, for the social cost analysis, the analysis period extends to 2055 for new facilities and to 2043 for existing facilities.[4] These profiles of costs by year were then discounted to the assumed year when this proposed rule would take effect, beginning of year 2007, at two values of the discount rate, 3% and 7%. These discount rate values reflect guidance from the Office of Management and Budget (OMB) regulatory analysis guidance document, Circular A-4 (OMB, 2003). After calculating the present value of these cost streams, EPA calculated their constant annual equivalent value (annualized value) using the annualization formula presented in Chapter B1, again using the two values of the discount rate, 3% and 7%.

Table E1-1: Summary of Annualized Direct Costs by Regulated Industry Segments (in millions, 2003 $)

	50 MGD All (Existing) / 2 MGD All (New)		200 MGD All (Existing) / 2 MGD All (New)		100 MGD CWB (Existing) / 2 MGD All (New)	
	3%	7%	3%	7%	3%	7%
Existing Manufacturing Facilities						
Primary Manufacturing Industries	$42.7	$45.1	$21.7	$23.1	$16.7	$17.4
Other Industries	$4.1	$4.4	$1.0	$0.9	$0.7	$0.7
Existing Electric Generators	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Total Existing Facilities[a]	$46.8	$49.5	$22.6	$24.0	$17.5	$18.1
New Oil & Gas Facilities	$3.2	$2.7	$3.2	$2.7	$3.2	$2.7
Total Direct Facility Costs[a]	**$50.0**	**$52.2**	**$25.9**	**$26.7**	**$20.7**	**$20.8**

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

Source: U.S. EPA Analysis, 2004.

[4] Tables E1-4 through E1-6 below present the time profiles of regulatory costs associated with each of the proposed options for existing facilities, combined with the proposed option for new offshore oil and gas extraction facilities.

E1-2 STATE AND FEDERAL ADMINISTRATIVE COSTS

Social costs also include costs to State and Federal governments of administering the permitting and compliance monitoring activities under the proposed regulation. State and Federal permitting authorities incur costs to administer the rule, including labor costs to write permits and to conduct compliance monitoring and enforcement activities. *Chapter D2: UMRA Analysis* presents more information on State and Federal implementation costs.

EPA's estimate of State and Federal government cost for administering the proposed rule is comparatively minor in relation to the estimated direct cost of regulatory compliance. At a 3% discount rate, EPA estimates administrative costs of $0.98 million (50 MGD All Option), $0.54 million (200 MGD All Option), and $0.57 million (100 MGD CWB Option). At a 7% discount rate, these costs amount to $0.89 million (50 MGD All Option), $0.45 million (200 MGD All Option), and $0.48 million (100 MGD CWB Option).

Table E1-2: Summary of Annualized Government Costs (in millions, 2003 $)

	50 MGD All (Existing) / 2 MGD All (New)		200 MGD All (Existing) / 2 MGD All (New)		100 MGD CWB (Existing) / 2 MGD All (New)	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
Existing Facilities:						
State Admin. Costs	$0.55	$0.55	$0.12	$0.12	$0.15	$0.16
Federal Admin. Costs	$0.01	$0.01	<$0.01	< $0.01	< $0.01	< $0.01
Total Existing Facilities Admin. Cost[a]	$0.56	$0.56	$0.12	$0.13	$0.15	$0.16
New OOGE Facilities:						
State Admin. Costs	n/a	n/a	n/a	n/a	n/a	n/a
Federal Admin. Costs	$0.42	$0.32	$0.42	$0.32	$0.42	$0.32
Total New OOGE Facilities Admin. Cost	$0.42	$0.32	$0.42	$0.32	$0.42	$0.32
Total Gov. Admin. Costs[a]	**$0.98**	**$0.89**	**$0.54**	**$0.45**	**$0.57**	**$0.48**

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

Source: U.S. EPA Analysis, 2004.

E1-3 TOTAL SOCIAL COST

Table E1-3 combines the information presented above by industry segment and major cost category – direct facility costs and administrative costs – and reports the total social costs of the three proposal options, discounted at a 3% and 7% rate. At a 3% discount rate the estimated total annualized social costs are $51.0 million for the 50 MGD All Option, $26.4 million for the 200 MGD All Option, and $21.3 million for the 100 MGD CWB Option. At a 7% discount rate the estimated total annualized social costs are $53.1 million for the 50 MGD All Option, $27.2 million for the 200 MGD All Option, and $21.3 million for the 100 MGD CWB Option (all values in 2003$).

As shown in Table E1-3, existing facilities account for the substantial majority of total social cost under all three proposal options. Since no Electric Generators would be subject to the national requirements under any of the three proposed options, Manufacturers account for all costs in the existing facilities segment. At a 3% discount rate, annualized pre-tax costs *per facility* in the Manufacturers segment amount to $349,000 for the 50 MGD All option, $920,000 for the 200 MGD All option, and $929,000 for the 100 MGD CWB option. At a 7% discount rate, annualized pre-tax costs in the Manufacturers segment amount to $369,000 for the 50 MGD All option, $974,000 for the 200 MGD All option, and $962,000 for the 100 MGD CWB option. Because the 200 MGD option and the 100 MGD option apply national categorical requirements to a smaller number of facilities than the 50 MGD option, they result in a lower total national cost but a higher cost per regulated facility. Facilities that are subject to the national requirements of the 200 MGD option and the 100 MGD option incur the same compliance costs as under the 50 MGD option; however, the average costs per regulated facility are higher under the 200 MGD and 100 MGD options because only the higher flow, and therefore higher cost, facilities incur costs under these options. For facilities in the new offshore oil and gas extraction industry segment, *per facility* costs under the proposed rule are approximately $30,000 at a 3% discount rate and $24,000 at a 7% discount rate.

Table E1-3: Summary of Annualized Social Costs (in millions, 2003 $)

	50 MGD All (Existing) / 2 MGD All (New)		200 MGD All (Existing) / 2 MGD All (New)		100 MGD CWB (Existing) / 2 MGD All (New)	
	3%	**7%**	**3%**	**7%**	**3%**	**7%**
Existing Facilities:						
Total Direct Facility Costs	$46.8	$49.5	$22.6	$24.0	$17.5	$18.1
Total Government Administrative Costs	$0.6	$0.6	$0.1	$0.1	$0.2	$0.2
Total Existing Facilities Social Cost	$47.3	$50.1	$22.8	$24.1	$17.6	$18.3
New OOGE Facilities:						
Total Direct Facility Costs	$3.2	$2.7	$3.2	$2.7	$3.2	$2.7
Total Government Administrative Costs	$0.4	$0.3	$0.4	$0.3	$0.4	$0.3
Total New OOGE Facilities Social Cost	$3.7	$3.0	$3.7	$3.0	$3.7	$3.0
Total Social Cost	**$51.0**	**$53.1**	**$26.4**	**$27.2**	**$21.3**	**$21.3**

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

Source: U.S. EPA Analysis, 2004.

Tables E1-4 through E1-6, starting on the following page, provide additional detail on the compliance cost calculations. The tables compile, for each of the three proposed options for existing facilities and the proposed option for new offshore oil and gas extraction facilities, the time profiles of costs incurred by the regulated industry segments, administrative costs, and total costs. The tables also report the calculated present and annualized values of costs at 3% and 7% discount rates. Time profiles for other options evaluated for existing facilities are presented in the appendix to this chapter.

Table E1-4: Time Profile of Compliance Costs for the 50 MGD for All Waterbodies Option for Existing Facilities and the Proposed Option for New OOGE Facilities (in millions; 2003$)

Year	Existing Facilities				New OOGE Facilities			Total
	Regulated Industry Segments		Administrative Costs	Total	O&G Facilities	Administrative Costs	Total	
	Man.	Generators						
2007	$3.2	$0.0	$0.2	$3.3	$1.9	$0.0	$1.9	$5.2
2008	$10.2	$0.0	$0.0	$10.2	$1.7	$0.0	$1.7	$12.0
2009	$15.4	$0.0	$0.0	$15.4	$1.8	$0.0	$1.8	$17.2
2010	$171.6	$0.0	$1.1	$172.6	$1.1	$0.0	$1.1	$173.7
2011	$178.4	$0.0	$2.1	$180.5	$1.6	$0.0	$1.6	$182.2
2012	$73.4	$0.0	$1.1	$74.4	$1.9	$0.5	$2.4	$76.8
2013	$109.9	$0.0	$0.9	$110.8	$2.2	$0.1	$2.4	$113.2
2014	$21.9	$0.0	$0.3	$22.2	$2.1	$0.7	$2.7	$24.9
2015	$22.2	$0.0	$0.4	$22.7	$1.8	$0.3	$2.0	$24.7
2016	$17.8	$0.0	$0.7	$18.6	$1.6	$0.3	$1.9	$20.5
2017	$18.2	$0.0	$0.4	$18.6	$4.1	$0.5	$4.6	$23.2
2018	$14.9	$0.0	$0.4	$15.3	$2.7	$0.3	$3.0	$18.2
2019	$18.8	$0.0	$0.2	$19.0	$3.7	$0.5	$4.2	$23.2
2020	$44.1	$0.0	$0.4	$44.5	$2.8	$0.3	$3.2	$47.7
2021	$81.0	$0.0	$0.7	$81.7	$2.8	$0.4	$3.2	$85.0
2022	$28.8	$0.0	$0.4	$29.2	$4.8	$0.7	$5.5	$34.7
2023	$57.9	$0.0	$0.4	$58.2	$2.9	$0.4	$3.3	$61.5
2024	$21.9	$0.0	$0.2	$22.1	$4.4	$0.7	$5.1	$27.2
2025	$22.2	$0.0	$0.4	$22.7	$3.0	$0.4	$3.4	$26.1
2026	$17.8	$0.0	$0.7	$18.6	$2.9	$0.4	$3.3	$21.9
2027	$18.2	$0.0	$0.4	$18.6	$4.9	$0.7	$5.6	$24.2
2028	$14.9	$0.0	$0.4	$15.3	$2.8	$0.3	$3.1	$18.4
2029	$18.8	$0.0	$0.2	$19.0	$4.1	$0.7	$4.7	$23.7
2030	$44.1	$0.0	$0.4	$44.5	$2.8	$0.3	$3.1	$47.7
2031	$81.0	$0.0	$0.7	$81.7	$2.8	$0.3	$3.1	$84.9
2032	$28.8	$0.0	$0.4	$29.2	$5.1	$0.7	$5.8	$35.0
2033	$57.9	$0.0	$0.4	$58.2	$2.8	$0.3	$3.1	$61.4
2034	$21.9	$0.0	$0.2	$22.1	$4.6	$0.7	$5.2	$27.3
2035	$22.2	$0.0	$0.4	$22.7	$2.8	$0.3	$3.1	$25.8
2036	$17.8	$0.0	$0.7	$18.6	$2.8	$0.3	$3.1	$21.7

Table E1-4: Time Profile of Compliance Costs for the 50 MGD for All Waterbodies Option for Existing Facilities and the Proposed Option for New OOGE Facilities (in millions; 2003$)

Year	Existing Facilities				New OOGE Facilities			Total
	Regulated Industry Segments		Administrative Costs	Total	O&G Facilities	Administrative Costs	Total	
	Man.	Generators						
2037	$18.2	$0.0	$0.4	$18.6	$3.9	$0.7	$4.6	$23.2
2038	$14.9	$0.0	$0.4	$15.3	$1.8	$0.3	$2.1	$17.4
2039	$14.2	$0.0	$0.2	$14.4	$3.0	$0.6	$3.6	$18.0
2040	$12.0	$0.0	$0.1	$12.1	$1.7	$0.3	$2.0	$14.1
2041	$6.2	$0.0	$0.1	$6.3	$1.7	$0.2	$1.9	$8.2
2042	$4.1	$0.0	$0.0	$4.1	$3.6	$0.5	$4.1	$8.3
2043	$0.5	$0.0	$0.0	$0.5	$1.6	$0.2	$1.8	$2.4
2044					$2.4	$0.4	$2.8	$2.8
2045					$1.5	$0.2	$1.7	$1.7
2046					$1.5	$0.2	$1.6	$1.6
2047					$2.1	$0.3	$2.4	$2.4
2048					$0.5	$0.1	$0.6	$0.6
2049					$1.0	$0.2	$1.3	$1.3
2050					$0.3	$0.1	$0.4	$0.4
2051					$0.2	$0.1	$0.3	$0.3
2052					$1.5	$0.1	$1.6	$1.6
2053					$0.1	$0.0	$0.2	$0.2
2054					$0.6	$0.1	$0.7	$0.7
2055					$0.0	$0.0	$0.1	$0.1
PV 3%	**$944.6**	**$0.0**	**$11.2**	**$955.8**	**$65.4**	**$8.5**	**$74.0**	**$1,029.8**
Annualized 3%	**$46.8**	**$0.0**	**$0.6**	**$47.3**	**$3.2**	**$0.4**	**$3.7**	**$51.0**
PV 7%	**$657.5**	**$0.0**	**$7.5**	**$665.0**	**$36.0**	**$4.3**	**$40.3**	**$705.3**
Annualized 7%	**$49.5**	**$0.0**	**$0.6**	**$50.1**	**$2.7**	**$0.3**	**$3.0**	**$53.1**

Source: U.S. EPA Analysis, 2004.

Table E1-5: Time Profile of Compliance Costs for the 200 MGD for All Waterbodies Option for Existing Facilities and the Proposed Option for New OOGE Facilities (in millions; 2003$)

Year	Existing Facilities				New OOGE Facilities			Total
	Regulated Industry Segments		Administrative Costs	Total	O&G Facilities	Administrative Costs	Total	
	Man.	Generators						
2007	$0.0	$0.0	$0.2	$0.2	$1.9	$0.0	$1.9	$2.1
2008	$1.4	$0.0	$0.0	$1.4	$1.7	$0.0	$1.7	$3.1
2009	$2.1	$0.0	$0.0	$2.1	$1.8	$0.0	$1.8	$3.9
2010	$129.1	$0.0	$0.0	$129.1	$1.1	$0.0	$1.1	$130.2
2011	$83.4	$0.0	$0.5	$83.8	$1.6	$0.0	$1.6	$85.4
2012	$12.1	$0.0	$0.1	$12.3	$1.9	$0.5	$2.4	$14.6
2013	$45.4	$0.0	$0.4	$45.8	$2.2	$0.1	$2.4	$48.1
2014	$7.4	$0.0	$0.1	$7.5	$2.1	$0.7	$2.7	$10.2
2015	$8.5	$0.0	$0.1	$8.5	$1.8	$0.3	$2.0	$10.6
2016	$7.4	$0.0	$0.2	$7.5	$1.6	$0.3	$1.9	$9.5
2017	$8.9	$0.0	$0.1	$9.0	$4.1	$0.5	$4.6	$13.5
2018	$7.4	$0.0	$0.1	$7.5	$2.7	$0.3	$3.0	$10.5
2019	$7.2	$0.0	$0.1	$7.3	$3.7	$0.5	$4.2	$11.5
2020	$12.7	$0.0	$0.0	$12.7	$2.8	$0.3	$3.2	$15.9
2021	$39.8	$0.0	$0.2	$40.0	$2.8	$0.4	$3.2	$43.2
2022	$14.6	$0.0	$0.1	$14.6	$4.8	$0.7	$5.5	$20.1
2023	$45.7	$0.0	$0.1	$45.8	$2.9	$0.4	$3.3	$49.1
2024	$7.3	$0.0	$0.1	$7.4	$4.4	$0.7	$5.1	$12.5
2025	$8.5	$0.0	$0.0	$8.5	$3.0	$0.4	$3.4	$11.9
2026	$7.4	$0.0	$0.2	$7.5	$2.9	$0.4	$3.3	$10.9
2027	$8.9	$0.0	$0.1	$9.0	$4.9	$0.7	$5.6	$14.6
2028	$7.4	$0.0	$0.1	$7.5	$2.8	$0.3	$3.1	$10.6
2029	$7.2	$0.0	$0.1	$7.3	$4.1	$0.7	$4.7	$12.0
2030	$12.7	$0.0	$0.0	$12.7	$2.8	$0.3	$3.1	$15.9
2031	$39.8	$0.0	$0.2	$40.0	$2.8	$0.3	$3.1	$43.1
2032	$14.6	$0.0	$0.1	$14.6	$5.1	$0.7	$5.8	$20.4
2033	$45.7	$0.0	$0.1	$45.8	$2.8	$0.3	$3.1	$48.9
2034	$7.3	$0.0	$0.1	$7.4	$4.6	$0.7	$5.2	$12.7
2035	$8.5	$0.0	$0.0	$8.5	$2.8	$0.3	$3.1	$11.6
2036	$7.4	$0.0	$0.2	$7.5	$2.8	$0.3	$3.1	$10.7
2037	$8.9	$0.0	$0.1	$9.0	$3.9	$0.7	$4.6	$13.6

Table E1-5: Time Profile of Compliance Costs for the 200 MGD for All Waterbodies Option for Existing Facilities and the Proposed Option for New OOGE Facilities (in millions; 2003$)

Year	Existing Facilities				New OOGE Facilities			Total
	Regulated Industry Segments		Administrative Costs	Total	O&G Facilities	Administrative Costs	Total	
	Man.	Generators						
2038	$7.4	$0.0	$0.1	$7.5	$1.8	$0.3	$2.1	$9.6
2039	$7.0	$0.0	$0.1	$7.1	$3.0	$0.6	$3.6	$10.6
2040	$6.7	$0.0	$0.0	$6.8	$1.7	$0.3	$2.0	$8.8
2041	$3.9	$0.0	$0.0	$3.9	$1.7	$0.2	$1.9	$5.9
2042	$3.0	$0.0	$0.0	$3.1	$3.6	$0.5	$4.1	$7.2
2043	$0.4	$0.0	$0.0	$0.4	$1.6	$0.2	$1.8	$2.2
2044					$2.4	$0.4	$2.8	$2.8
2045					$1.5	$0.2	$1.7	$1.7
2046					$1.5	$0.2	$1.6	$1.6
2047					$2.1	$0.3	$2.4	$2.4
2048					$0.5	$0.1	$0.6	$0.6
2049					$1.0	$0.2	$1.3	$1.3
2050					$0.3	$0.1	$0.4	$0.4
2051					$0.2	$0.1	$0.3	$0.3
2052					$1.5	$0.1	$1.6	$1.6
2053					$0.1	$0.0	$0.2	$0.2
2054					$0.6	$0.1	$0.7	$0.7
2055					$0.0	$0.0	$0.1	$0.1
PV 3%	**$457.2**	**$0.0**	**$2.5**	**$459.7**	**$65.4**	**$8.5**	**$74.0**	**$533.6**
Annualized 3%	**$22.6**	**$0.0**	**$0.1**	**$22.8**	**$3.2**	**$0.4**	**$3.7**	**$26.4**
PV 7%	**$318.7**	**$0.0**	**$1.7**	**$320.3**	**$36.0**	**$4.3**	**$40.3**	**$360.6**
Annualized 7%	**$24.0**	**$0.0**	**$0.1**	**$24.1**	**$2.7**	**$0.3**	**$3.0**	**$27.2**

Source: U.S. EPA Analysis, 2004.

Table E1-6: Time Profile of Compliance Costs for the 100 MGD for Certain Waterbodies Option for Existing Facilities and the Proposed Option for New OOGE Facilities (in millions; 2003$)

Year	Existing Facilities				New OOGE Facilities			Total
	Regulated Industry Segments		Administrative Costs	Total	O&G Facilities	Administrative Costs	Total	
	Man.	Generators						
2007	$0.4	$0.0	$0.2	$0.6	$1.9	$0.0	$1.9	$2.5
2008	$3.8	$0.0	$0.0	$3.8	$1.7	$0.0	$1.7	$5.6
2009	$3.9	$0.0	$0.0	$3.9	$1.8	$0.0	$1.8	$5.7
2010	$8.8	$0.0	$0.2	$9.0	$1.1	$0.0	$1.1	$10.1
2011	$138.9	$0.0	$0.8	$139.7	$1.6	$0.0	$1.6	$141.4
2012	$11.4	$0.0	$0.1	$11.5	$1.9	$0.5	$2.4	$13.9
2013	$34.9	$0.0	$0.4	$35.3	$2.2	$0.1	$2.4	$37.7
2014	$5.3	$0.0	$0.0	$5.4	$2.1	$0.7	$2.7	$8.1
2015	$8.2	$0.0	$0.1	$8.3	$1.8	$0.3	$2.0	$10.4
2016	$5.2	$0.0	$0.3	$5.4	$1.6	$0.3	$1.9	$7.4
2017	$6.5	$0.0	$0.1	$6.6	$4.1	$0.5	$4.6	$11.2
2018	$5.2	$0.0	$0.1	$5.3	$2.7	$0.3	$3.0	$8.3
2019	$5.2	$0.0	$0.0	$5.2	$3.7	$0.5	$4.2	$9.5
2020	$8.2	$0.0	$0.1	$8.3	$2.8	$0.3	$3.2	$11.5
2021	$41.1	$0.0	$0.3	$41.4	$2.8	$0.4	$3.2	$44.6
2022	$12.2	$0.0	$0.1	$12.2	$4.8	$0.7	$5.5	$17.7
2023	$35.3	$0.0	$0.1	$35.4	$2.9	$0.4	$3.3	$38.7
2024	$5.3	$0.0	$0.0	$5.4	$4.4	$0.7	$5.1	$10.5
2025	$8.2	$0.0	$0.1	$8.3	$3.0	$0.4	$3.4	$11.7
2026	$5.2	$0.0	$0.3	$5.4	$2.9	$0.4	$3.3	$8.8
2027	$6.5	$0.0	$0.1	$6.6	$4.9	$0.7	$5.6	$12.2
2028	$5.2	$0.0	$0.1	$5.3	$2.8	$0.3	$3.1	$8.4
2029	$5.2	$0.0	$0.0	$5.2	$4.1	$0.7	$4.7	$10.0
2030	$8.2	$0.0	$0.1	$8.3	$2.8	$0.3	$3.1	$11.4
2031	$41.1	$0.0	$0.3	$41.4	$2.8	$0.3	$3.1	$44.5
2032	$12.2	$0.0	$0.1	$12.2	$5.1	$0.7	$5.8	$18.0
2033	$35.3	$0.0	$0.1	$35.4	$2.8	$0.3	$3.1	$38.6
2034	$5.3	$0.0	$0.0	$5.4	$4.6	$0.7	$5.2	$10.6
2035	$8.2	$0.0	$0.1	$8.3	$2.8	$0.3	$3.1	$11.4
2036	$5.2	$0.0	$0.3	$5.4	$2.8	$0.3	$3.1	$8.6
2037	$6.5	$0.0	$0.1	$6.6	$3.9	$0.7	$4.6	$11.2
2038	$5.2	$0.0	$0.1	$5.3	$1.8	$0.3	$2.1	$7.4
2039	$4.8	$0.0	$0.0	$4.8	$3.0	$0.6	$3.6	$8.4
2040	$4.7	$0.0	$0.0	$4.7	$1.7	$0.3	$2.0	$6.7
2041	$2.2	$0.0	$0.0	$2.2	$1.7	$0.2	$1.9	$4.1
2042	$1.3	$0.0	$0.0	$1.3	$3.6	$0.5	$4.1	$5.4
2043	$0.4	$0.0	$0.0	$0.4	$1.6	$0.2	$1.8	$2.2

Table E1-6: Time Profile of Compliance Costs for the 100 MGD for Certain Waterbodies Option for Existing Facilities and the Proposed Option for New OOGE Facilities (in millions; 2003$)

Year	Existing Facilities				New OOGE Facilities			Total
	Regulated Industry Segments		Administrative Costs	Total	O&G Facilities	Administrative Costs	Total	
	Man.	Generators						
2044					$2.4	$0.4	$2.8	$2.8
2045					$1.5	$0.2	$1.7	$1.7
2046					$1.5	$0.2	$1.6	$1.6
2047					$2.1	$0.3	$2.4	$2.4
2048					$0.5	$0.1	$0.6	$0.6
2049					$1.0	$0.2	$1.3	$1.3
2050					$0.3	$0.1	$0.4	$0.4
2051					$0.2	$0.1	$0.3	$0.3
2052					$1.5	$0.1	$1.6	$1.6
2053					$0.1	$0.0	$0.2	$0.2
2054					$0.6	$0.1	$0.7	$0.7
2055					$0.0	$0.0	$0.1	$0.1
PV 3%	**$352.8**	**$0.0**	**$3.1**	**$355.9**	**$65.4**	**$8.5**	**$74.0**	**$429.9**
Annualized 3%	**$17.5**	**$0.0**	**$0.2**	**$17.6**	**$3.2**	**$0.4**	**$3.7**	**$21.3**
PV 7%	**$240.4**	**$0.0**	**$2.1**	**$242.5**	**$36.0**	**$4.3**	**$40.3**	**$282.8**
Annualized 7%	**$18.1**	**$0.0**	**$0.2**	**$18.3**	**$2.7**	**$0.3**	**$3.0**	**$21.3**

Source: U.S. EPA Analysis, 2004.

E1-4 LIMITATIONS AND UNCERTAINTIES

EPA did not include in its estimate of social costs the cost associated with unemployment that may result from facility closures. Potential unemployment-related costs would include the cost of administering unemployment programs for workers who are projected to lose employment (but not the cost of unemployment benefits, which are a transfer payment within society); and an estimate of the amount that workers would be willing to pay to avoid involuntary unemployment. However, from its facility impact analysis, EPA estimates that no facilities would close as a result of the proposed rule. EPA also did not recognize any possible savings in unemployment-related costs from jobs created by the rule as a negative cost (benefit) of the regulation. Accordingly, EPA estimates a zero cost of unemployment for the proposed rule.

Another key uncertainty factor in the analysis of costs to society is EPA's estimate of the cost of installation downtime in Manufacturers facilities. As described above, EPA adopted the conservative assumption that the production cost for replacing the goods and services not provided by complying facilities due to installation downtime would be approximately equal to the price received for those goods and services in the market. To the extent that these replacement goods and services are produced at a cost less than selling price, this assumption would lead to an overestimate of the cost to society of installation downtime. The amount of potential overestimation is not known.

GLOSSARY

consumer surplus: The value that consumers derive from goods and services above the price they have to pay to obtain the goods and services.

opportunity cost: The lost value of alternative uses of resources (capital, labor, and raw materials) used in regulatory compliance.

producer surplus: The difference between what producers' earn on their output and the economic costs of producing that output, including a normal return on capital.

social cost: The costs incurred by society as a whole as a result of the proposed rule. Social costs do not include costs that are transfers among parties that do not represent a new cost overall.

REFERENCES

Office of Management and Budget (OMB). 2003. Circular A-4, Regulatory Analysis. September 17, 2003. Available at http://www.whitehouse.gov/omb/circulars/a004/a-4.pdf.

Appendix to Chapter E1

INTRODUCTION

APPENDIX CONTENTS

This appendix presents the social cost results for five other options evaluated for potential Phase III existing facilities. For all options, facility counts and other results only include those potential Phase III existing facilities that are (1) non-baseline closures and (2) subject to national categorical requirements under the option. See *Chapter B3: Economic Impact Analysis for Manufacturers* and *Chapter B5: Summary of Electric Generator Costs* for more information on baseline closures and counts of facilities subject to national categorical requirements under each option. See the main body of this chapter for a description of data sources and methodologies used in these analyses.

E1A-1 COSTS OF COMPLIANCE BY REGULATED INDUSTRY SEGMENT

Table E1A-1 below summarizes total direct facility costs for the five other options evaluated for existing facilities, at a 3% and a 7% discount rate. For a description of this analysis, see section E1-1 above.

Table E1A-1: Summary of Annualized Direct Costs by Regulated Industry Segments Existing Facilities (in millions, 2003$)

	Option 3	Option 4	Option 2	Option 1	Option 6
			3% Discount Rate		
Manufacturers					
Primary Manufacturing Industries	$58.2	$62.1	$66.2	$68.3	$85.9
Other Industries	$4.4	$4.3	$4.4	$4.4	$5.2
Electric Generators	$1.5	$0.7	$1.9	$2.2	$2.9
Total Direct Facility Costs[a]	**$64.1**	**$67.1**	**$72.6**	**$75.0**	**$94.0**
			7% Discount Rate		
Manufacturers					
Primary Manufacturing Industries	$62.5	$67.8	$71.7	$73.8	$92.5
Other Industries	$4.7	$4.6	$4.7	$4.7	$5.5
Electric Generators	$1.5	$0.7	$1.8	$2.1	$2.8
Total Direct Facility Costs[a]	**$68.7**	**$73.0**	**$78.3**	**$80.7**	**$100.8**

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

Source: U.S. EPA Analysis, 2004.

E1A-2 STATE AND FEDERAL ADMINISTRATIVE COSTS

Table E1A-2 presents annualized costs to State and Federal governments of administering the permitting and compliance monitoring activities for the five other options evaluated for existing facilities, at a 3% and a 7% discount rate. For a description of this analysis, see section E1-2 above.

Table E1A-2: Summary of Annualized Government Costs for Existing Facilities (in millions, 2003$)

	Option 3	Option 4	Option 2	Option 1	Option 6
3% Discount Rate					
State Admin. Costs	$0.91	$0.81	$1.05	$1.08	$1.66
Federal Admin. Costs	$0.02	$0.01	$0.02	$0.02	$0.03
Total Gov. Admin. Costs[a]	**$0.92**	**$0.83**	**$1.07**	**$1.10**	**$1.69**
7% Discount Rate					
State Admin. Costs	$0.90	$0.81	$1.05	$1.08	$1.65
Federal Admin. Costs	$0.02	$0.02	$0.02	$0.02	$0.04
Total Gov. Admin. Costs[a]	**$0.92**	**$0.83**	**$1.07**	**$1.10**	**$1.69**

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

Source: U.S. EPA Analysis, 2004.

E1A-3 TOTAL SOCIAL COST

Table E1A-3 presents the total social costs of the five other options evaluated for existing facilities, including direct facility costs and government administrative costs, at a 3% and a 7% discount rate. Tables E1A-4 through E1A-8 present the time profiles for the five other options. For a description of these analyses, see section E1-3 above.

Table E1A-3: Summary of Annualized Social Costs for Existing Facilities (in millions, 2003$)

	Option 3	Option 4	Option 2	Option 1	Option 6
3% Discount Rate					
Total Direct Facility Costs	$64.1	$67.1	$72.6	$75.0	$94.0
Total Government Administrative Costs	$0.9	$0.8	$1.1	$1.1	$1.7
Total Social Cost[a]	**$65.0**	**$67.9**	**$73.7**	**$76.1**	**$95.7**
7% Discount Rate					
Total Direct Facility Costs	$68.7	$73.0	$78.3	$80.7	$100.8
Total Government Administrative Costs	$0.9	$0.8	$1.1	$1.1	$1.7
Total Social Cost[a]	**$69.6**	**$73.9**	**$79.3**	**$81.8**	**$102.5**

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

Source: U.S. EPA Analysis, 2004.

Table E1A-4: Time Profile of Compliance Costs for Existing Facilities - Option 3 (in millions; 2003$)

Year	Costs of Compliance by Regulated Industry Segments		Administrative Costs	Total Cost
	Manufacturers	Generators		
2007	$3.5	$0.2	$0.2	$3.9
2008	$14.0	$0.9	$0.0	$14.9
2009	$23.4	$1.4	$0.0	$24.8
2010	$184.6	$1.8	$1.6	$188.0
2011	$190.4	$3.0	$2.7	$196.1
2012	$277.3	$2.0	$2.3	$281.5
2013	$116.4	$1.0	$1.6	$119.0
2014	$28.1	$2.2	$0.8	$31.0
2015	$28.9	$1.0	$0.7	$30.6
2016	$26.7	$1.4	$1.0	$29.1
2017	$24.3	$0.7	$0.9	$25.9
2018	$18.6	$1.1	$0.7	$20.4
2019	$23.2	$1.4	$0.4	$25.0
2020	$52.9	$1.5	$0.7	$55.1
2021	$91.8	$2.8	$1.0	$95.6
2022	$36.8	$1.7	$0.9	$39.4
2023	$64.4	$1.1	$0.7	$66.1
2024	$28.0	$2.2	$0.4	$30.6
2025	$28.9	$1.0	$0.7	$30.6
2026	$26.7	$1.4	$1.0	$29.1
2027	$24.3	$0.7	$0.9	$25.9
2028	$18.6	$1.1	$0.7	$20.4
2029	$23.2	$1.4	$0.4	$25.0
2030	$52.9	$1.5	$0.7	$55.1
2031	$91.8	$2.8	$1.0	$95.6
2032	$36.8	$1.7	$0.9	$39.4
2033	$64.4	$1.1	$0.7	$66.1
2034	$28.0	$2.2	$0.4	$30.6
2035	$28.9	$1.0	$0.7	$30.6
2036	$26.7	$1.4	$1.0	$29.1
2037	$24.3	$0.7	$0.9	$25.9
2038	$18.6	$1.1	$0.7	$20.4
2039	$17.3	$0.6	$0.4	$18.3
2040	$14.6	$0.4	$0.2	$15.3
2041	$8.3	$0.3	$0.1	$8.8
2042	$5.1	$0.1	$0.1	$5.3
2043	$0.8	$0.1	$0.0	$1.0
PV 3%	**$1,263.6**	**$30.9**	**$18.7**	**$1,313.2**
Annualized 3%	**$62.6**	**$1.5**	**$0.9**	**$65.0**
PV 7%	**$892.1**	**$19.5**	**$12.2**	**$923.8**
Annualized 7%	**$67.2**	**$1.5**	**$0.9**	**$69.6**

Source: U.S. EPA Analysis, 2004.

Table E1A-5: Time Profile of Compliance Costs for Existing Facilities - Option 4 (in millions; 2003$)

Year	Costs of Compliance by Regulated Industry Segments		Administrative Costs	Total Cost
	Manufacturers	Generators		
2007	$3.2	$0.0	$0.2	$3.3
2008	$13.6	$0.3	$0.0	$13.9
2009	$22.4	$0.6	$0.0	$23.0
2010	$180.9	$0.6	$1.1	$182.6
2011	$291.4	$2.0	$3.0	$296.5
2012	$282.0	$0.5	$2.1	$284.6
2013	$115.6	$0.5	$1.5	$117.7
2014	$25.1	$1.3	$0.6	$27.0
2015	$28.8	$0.6	$0.5	$29.9
2016	$25.0	$0.7	$1.1	$26.8
2017	$23.7	$0.3	$0.8	$24.8
2018	$19.5	$0.6	$0.5	$20.7
2019	$22.0	$0.3	$0.3	$22.6
2020	$50.6	$0.6	$0.5	$51.8
2021	$89.8	$1.0	$1.1	$91.9
2022	$39.7	$0.3	$0.8	$40.8
2023	$64.0	$0.6	$0.5	$65.2
2024	$25.1	$1.2	$0.3	$26.6
2025	$28.8	$0.6	$0.5	$29.9
2026	$25.0	$0.7	$1.1	$26.8
2027	$23.7	$0.3	$0.8	$24.8
2028	$19.5	$0.6	$0.5	$20.7
2029	$22.0	$0.3	$0.3	$22.6
2030	$50.6	$0.6	$0.5	$51.8
2031	$89.8	$1.0	$1.1	$91.9
2032	$39.7	$0.3	$0.8	$40.8
2033	$64.0	$0.6	$0.5	$65.2
2034	$25.1	$1.2	$0.3	$26.6
2035	$28.8	$0.6	$0.5	$29.9
2036	$25.0	$0.7	$1.1	$26.8
2037	$23.7	$0.3	$0.8	$24.8
2038	$19.5	$0.6	$0.5	$20.7
2039	$17.4	$0.3	$0.3	$18.0
2040	$15.2	$0.3	$0.2	$15.7
2041	$8.4	$0.2	$0.1	$8.7
2042	$5.1	$0.1	$0.1	$5.2
2043	$0.8	$0.1	$0.0	$0.9
PV 3%	**$1,340.4**	**$14.1**	**$16.7**	**$1,371.2**
Annualized 3%	**$66.4**	**$0.7**	**$0.8**	**$67.9**
PV 7%	**$960.9**	**$8.9**	**$11.0**	**$980.8**
Annualized 7%	**$72.4**	**$0.7**	**$0.8**	**$73.9**

Source: U.S. EPA Analysis, 2004.

Table E1A-6: Time Profile of Compliance Costs for Existing Facilities - Option 2 (in millions; 2003$)

Year	Costs of Compliance by Regulated Industry Segments		Administrative Costs	Total Cost
	Manufacturers	Generators		
2007	$3.5	$0.2	$0.2	$3.9
2008	$15.0	$1.0	$0.0	$16.0
2009	$25.6	$1.8	$0.0	$27.4
2010	$187.5	$2.2	$1.6	$191.4
2011	$298.4	$3.8	$3.3	$305.5
2012	$286.1	$2.2	$2.9	$291.2
2013	$120.9	$1.2	$2.0	$124.1
2014	$30.2	$3.3	$0.9	$34.4
2015	$31.7	$1.2	$0.7	$33.6
2016	$29.5	$1.9	$1.2	$32.7
2017	$26.9	$0.9	$1.1	$28.8
2018	$22.1	$1.4	$0.7	$24.2
2019	$25.3	$1.6	$0.5	$27.3
2020	$55.6	$1.8	$0.7	$58.2
2021	$96.0	$2.8	$1.2	$100.0
2022	$43.6	$1.9	$1.1	$46.6
2023	$69.4	$1.4	$0.7	$71.4
2024	$30.1	$3.3	$0.5	$33.9
2025	$31.7	$1.2	$0.7	$33.6
2026	$29.5	$1.9	$1.2	$32.7
2027	$26.9	$0.9	$1.1	$28.8
2028	$22.1	$1.4	$0.7	$24.2
2029	$25.3	$1.6	$0.5	$27.3
2030	$55.6	$1.8	$0.7	$58.2
2031	$96.0	$2.8	$1.2	$100.0
2032	$43.6	$1.9	$1.1	$46.6
2033	$69.4	$1.4	$0.7	$71.4
2034	$30.1	$3.3	$0.5	$33.9
2035	$31.7	$1.2	$0.7	$33.6
2036	$29.5	$1.9	$1.2	$32.7
2037	$26.9	$0.9	$1.1	$28.8
2038	$22.1	$1.4	$0.7	$24.2
2039	$19.4	$0.8	$0.5	$20.7
2040	$16.7	$0.6	$0.2	$17.6
2041	$9.7	$0.5	$0.2	$10.3
2042	$5.9	$0.2	$0.1	$6.2
2043	$1.1	$0.2	$0.0	$1.3
PV 3%	**$1,427.1**	**$38.6**	**$21.6**	**$1,487.3**
Annualized 3%	**$70.7**	**$1.9**	**$1.1**	**$73.7**
PV 7%	**$1,014.8**	**$24.3**	**$14.2**	**$1,053.3**
Annualized 7%	**$76.4**	**$1.8**	**$1.1**	**$79.3**

Source: U.S. EPA Analysis, 2004.

Table E1A-7: Time Profile of Compliance Costs for Existing Facilities - Option 1 (in millions; 2003$)

Year	Costs of Compliance by Regulated Industry Segments		Administrative Costs	Total Cost
	Manufacturers	Generators		
2007	$3.5	$0.2	$0.2	$3.9
2008	$15.1	$1.0	$0.0	$16.1
2009	$26.1	$1.8	$0.0	$27.9
2010	$201.3	$3.1	$1.7	$206.0
2011	$299.7	$4.0	$3.3	$306.9
2012	$290.1	$2.6	$3.1	$295.9
2013	$122.0	$1.4	$2.0	$125.3
2014	$31.3	$3.8	$1.0	$36.1
2015	$32.7	$1.4	$0.8	$34.9
2016	$31.1	$2.2	$1.2	$34.5
2017	$27.9	$1.1	$1.1	$30.2
2018	$23.1	$1.6	$0.7	$25.4
2019	$26.4	$1.8	$0.5	$28.6
2020	$58.6	$2.4	$0.7	$61.7
2021	$97.6	$3.0	$1.2	$101.8
2022	$47.7	$2.3	$1.1	$51.2
2023	$70.4	$1.6	$0.7	$72.7
2024	$31.2	$3.3	$0.5	$35.0
2025	$32.7	$1.4	$0.7	$34.9
2026	$31.1	$2.2	$1.2	$34.5
2027	$27.9	$1.1	$1.1	$30.2
2028	$23.1	$1.6	$0.7	$25.4
2029	$26.4	$1.8	$0.5	$28.6
2030	$58.6	$2.4	$0.7	$61.7
2031	$97.6	$3.0	$1.2	$101.8
2032	$47.7	$2.3	$1.1	$51.2
2033	$70.4	$1.6	$0.7	$72.7
2034	$31.2	$3.3	$0.5	$35.0
2035	$32.7	$1.4	$0.7	$34.9
2036	$31.1	$2.2	$1.2	$34.5
2037	$27.9	$1.1	$1.1	$30.2
2038	$23.1	$1.6	$0.7	$25.4
2039	$20.4	$1.0	$0.5	$21.9
2040	$17.6	$0.8	$0.2	$18.6
2041	$10.6	$0.6	$0.2	$11.4
2042	$5.9	$0.3	$0.1	$6.2
2043	$1.1	$0.3	$0.0	$1.4
PV 3%	**$1,469.5**	**$43.9**	**$22.3**	**$1,535.7**
Annualized 3%	**$72.8**	**$2.2**	**1.1**	**$76.1**
PV 7%	**$1,043.3**	**$27.6**	**$14.6**	**$1,085.6**
Annualized 7%	**$78.6**	**$2.1**	**$1.1**	**$81.8**

Source: U.S. EPA Analysis, 2004.

Table E1A-8: Time Profile of Compliance Costs for Existing Facilities - Option 6 (in millions; 2003$)

Year	Costs of Compliance by Regulated Industry Segments		Administrative Costs	Total Cost
	Manufacturers	Generators		
2007	$5.5	$0.2	$0.2	$6.0
2008	$22.8	$1.0	$0.0	$23.8
2009	$36.7	$2.0	$0.0	$38.7
2010	$259.6	$3.5	$3.0	$266.2
2011	$400.0	$5.2	$5.0	$410.1
2012	$308.6	$4.0	$4.1	$316.7
2013	$131.9	$2.6	$3.1	$137.6
2014	$42.8	$4.9	$1.9	$49.6
2015	$43.7	$1.8	$1.3	$46.8
2016	$40.1	$2.5	$1.9	$44.5
2017	$37.6	$2.0	$1.5	$41.1
2018	$31.6	$2.8	$1.1	$35.5
2019	$36.5	$2.2	$0.8	$39.6
2020	$72.5	$2.7	$1.3	$76.5
2021	$124.3	$3.4	$1.8	$129.5
2022	$65.0	$3.2	$1.5	$69.7
2023	$80.3	$2.9	$1.1	$84.3
2024	$42.6	$4.2	$0.8	$47.7
2025	$43.7	$1.8	$1.3	$46.7
2026	$40.1	$2.5	$1.8	$44.5
2027	$37.6	$2.0	$1.5	$41.1
2028	$31.6	$2.8	$1.1	$35.5
2029	$36.5	$2.2	$0.8	$39.6
2030	$72.5	$2.7	$1.3	$76.5
2031	$124.3	$3.4	$1.8	$129.5
2032	$65.0	$3.2	$1.5	$69.7
2033	$80.3	$2.9	$1.1	$84.3
2034	$42.6	$4.2	$0.8	$47.7
2035	$43.7	$1.8	$1.3	$46.7
2036	$40.1	$2.5	$1.8	$44.5
2037	$37.6	$2.0	$1.5	$41.1
2038	$31.6	$2.8	$1.1	$35.5
2039	$26.5	$1.3	$0.8	$28.7
2040	$22.2	$1.1	$0.3	$23.6
2041	$13.0	$0.9	$0.2	$14.2
2042	$7.5	$0.5	$0.1	$8.1
2043	$1.7	$0.5	$0.0	$2.2
PV 3%	**$1,839.0**	**$58.8**	**$34.2**	**$1,932.0**
Annualized 3%	**$91.1**	**$2.9**	**$1.7**	**$95.7**
PV 7%	**$1,301.3**	**$36.6**	**$22.4**	**$1,360.3**
Annualized 7%	**$98.0**	**$2.8**	**$1.7**	**$102.5**

Source: U.S. EPA Analysis, 2004.

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Chapter E2: Summary of Benefits

INTRODUCTION

This chapter summarizes the EPA's benefits analysis conducted in developing the Proposed Section 316(b) Rule for Phase III Facilities and presents the total monetary value of regional and national baseline losses and of benefits of the three proposed options for Phase III existing facilities:

- the "50 MGD for All Waterbodies" option ("50 MGD All"),
- the "200 MGD for All Waterbodies" option ("200 MGD All"), and
- the "100 MGD for Certain Waterbodies" option ("100 MGD CWB").

CHAPTER CONTENTS

Benefits results for five other options evaluated by EPA, but not proposed, are presented in the appendix to this chapter.

The *Regional Benefits Assessment for the Proposed Section 316(b) Rule for Phase III Facilities* (RBA) provides greater detail on the methods and data used in the regional analyses (U.S. EPA, 2004). See Chapter A1 for a discussion of the methods used to estimate impingement and entrainment (I&E), and see Chapters A2 through A9 for discussion of the methods used to estimate the value of I&E losses and the benefits of the options evaluated for the proposed rule. The results of the regional analyses are presented in Parts B through G of the RBA.

EPA was unable to assess benefits of reducing I&E at new offshore oil and gas extraction facilities due to significant data gaps at the time of proposal. Therefore, the benefits estimates presented in this section are underestimates because they do not reflect benefits associated with reducing I&E at new offshore oil and gas extraction facilities.

E2-1 CALCULATING LOSSES AND BENEFITS

EPA's analysis of national baseline losses and benefits under the evaluated options includes 603 sample-weighted facilities in seven case study regions, excluding facilities that are expected to close in the baseline. The Agency calculated baseline losses by summing losses from all 603 facilities. EPA's estimates of benefits are based on only those facilities that have requirements under each option.

Quantifying and monetizing reductions in I&E due to the evaluated options considered for the proposed rule is challenging. As described in Chapters A3 and A6 of the RBA, EPA has estimated non-use values only qualitatively and, as a result, the estimated total benefits of the evaluated options reflect use values only. The RBA discusses specific limitations and uncertainties associated with estimation of commercial and recreational benefits at the regional level. National benefit estimates, which are based on the regional estimates, are subject to the same uncertainties. The overall effect of these uncertainties is of unknown magnitude and direction (i.e., the estimates may over- or understate the anticipated national-level of use benefits); however, EPA has no data to indicate that the results for any of the benefit categories are atypical or unreasonable.

E2-2 SUMMARY OF BASELINE LOSSES AND EXPECTED REDUCTIONS IN I&E

Based on the results of the regional analyses, EPA calculated total baseline I&E losses and the amount by which these losses would be reduced under each of the evaluated options. Losses are presented using two measures of I&E:

1. Age-one equivalent losses – the number of individual fish of different ages impinged and entrained by facility intakes, expressed as age-one equivalents; and

2. Foregone fishery yield – pounds of commercial harvest and numbers of recreational fish and shellfish that are not harvested due to I&E, including indirect losses of harvested species due to losses of forage species.

Table E2-1 presents baseline I&E losses for both measures. As reported in Table E2-1, EPA estimates total national losses of age-one equivalents for all 603 facilities of 120 million fish. Nationwide, EPA estimates that 4.2 million pounds of fishery yield per year is foregone under current rates of I&E. Approximately 37% of all age-one equivalent losses, or 44.2 million fish, occur in the Inland region. The Gulf of Mexico region has the highest foregone fishery yields with approximately 2 million pounds, followed by the Mid-Atlantic region with approximately 0.9 million pounds. More detailed discussions of the I&E losses in each region are provided in Parts B through G of the RBA.

Table E2-1: Total Annual Baseline I&E Losses for Potential Phase III Existing Facilities by Region (thousands)

Region	Age-One Equivalents	Foregone Fishery Yield (lbs)
California	1,310	96
North Atlantic	2,340	45
Mid-Atlantic	23,200	920
South Atlantic	1,520	123
Gulf of Mexico	12,700	1,990
Great Lakes	34,400	489
Inland	44,200	495
National Total	**120,000**	**4,160**

Source: U.S. EPA Analysis, 2004.

To gauge the expected benefits of the proposed options, EPA estimated the extent to which these options would reduce the estimated baseline losses. These avoided losses are based on the expected reductions in I&E at each facility from implementation of the required compliance technologies. Table E2-2 reports, by region and option, the expected percent reductions in I&E, and the estimated quantities of reduction in (1) losses in age-one equivalents and (2) foregone fishery yield. At the national level, EPA estimates that the 50 MGD All option would reduce age-one equivalent losses by 49.5 million fish and fishery yield loss by 2.2 million pounds. In comparison, the 200 MGD All option and the 100 MGD CWB option apply to smaller numbers of facilities and would result in slightly smaller reductions in I&E. The 200 MGD All option would reduce age-one equivalent losses by 34.0 million fish and fishery yield losses by 1.4 million pounds. The 100 MGD All option would reduce age-one equivalent losses by 29.8 million fish and fishery yield losses by 1.9 million pounds.

The study regions show substantial variation in the estimated reductions in I&E losses and avoided losses in age-one equivalents and foregone fishery yield. As reported in Table E2-2, the largest percentage reductions in I&E occur in the Gulf of Mexico for both the 50 MGD All and 100 MGD CWB options with 76% and 57%, respectively. The 200 MGD All option has the largest reductions in I&E in the Mid-Atlantic region with 65% and 49%, respectively.

Percentage reductions in entrainment are less substantial, overall, than the impingement reductions. However, the Great Lakes region shows larger percentage reductions in entrainment than impingement for each of the three proposed options, where entrainment reductions range from 37% to 43%, and impingement reductions are 21% to 33%.

In terms of avoided age-one equivalent losses, the Inland region accounts for the largest reductions for the 50 MGD All option with approximately 30% of avoided losses. Under the 200 MGD All and the 100 MGD CWB options, the Mid-Atlantic region accounts for the largest reductions in total avoided age-one equivalent losses with 35% and 40%, respectively.

On the basis of avoided losses in fishery yield, the Gulf of Mexico generates the greatest benefits under each of the three options, followed by the Mid-Atlantic region. Together, these two regions account for 83%, 84%, and 92% of the avoided fishery yield losses achieved by the 50 MGD All, the 200 MGD All, and the 100 MGD CWB options, respectively.

More detailed discussions of regional benefits are provided in Parts B through G of the RBA.

Table E2-2: Expected Reduction in I&E for Phase III Existing Facilities by Option and Region

Region	Number of Facilities Installing Technology	Impingement	Entrainment	Age-One Equivalents (thousands)	Foregone Fishery Yield (thousands; lbs)
50 MGD All Option					
California	1	39%	29%	383	28
North Atlantic	4	43%	40%	930	18
Mid-Atlantic	3	73%	55%	13,400	600
South Atlantic[a]	0	0%	0%	0	0
Gulf of Mexico	7	76%	57%	8,380	1,250
Great Lakes	19	33%	43%	11,600	169
Inland	69	37%	27%	14,800	157
National Total	**103**			**49,493**	**2,222**
200 MGD All Option					
California[b]	0	0%	0%	0	0
North Atlantic	1	11%	8%	198	4
Mid-Atlantic	2	65%	49%	11,900	534
South Atlantic[a]	0	0%	0%	0	0
Gulf of Mexico	2	41%	31%	4,580	682
Great Lakes	5	21%	37%	7,710	116
Inland	12	22%	21%	9,650	107
National Total	**22**			**34,038**	**1,443**
100 MGD CWB Option					
California[b]	0	0%	0%	0	0
North Atlantic	3	43%	32%	754	15
Mid-Atlantic	2	65%	49%	11,900	534
South Atlantic[a]	0	0%	0%	0	0
Gulf of Mexico	7	76%	57%	8,380	1,250
Great Lakes	6	24%	40%	8,740	130
Inland[c]	0	0%	0%	0	0
National Total	**18**			**29,774**	**1,929**

[a] No I&E reductions are expected in the South Atlantic region because all potentially regulated facilities in this region withdraw less than 50 MGD and therefore would not be required to install technologies to comply with the proposed options.
[b] No I&E reductions are expected in the California region because all potentially regulated facilities in this region withdraw less than 100 MGD and therefore would not be required to install technologies to comply with the 200 MGD All and the 100 MGD CWB options.
[c] The 100 MGD CWB option would not apply national categorical requirements to facilities located on freshwater rivers and lakes/reservoirs. Thus, no I&E reductions are expected at the potentially regulated facilities in the Inland region.

Source: U.S. EPA Analysis, 2004.

E2-3 TIME PROFILE OF BENEFITS

To account for the difference in timing of benefits and costs, EPA developed a time profile of total benefits from all Phase III facilities that reflects when benefits from each facility would be realized. For each study region, EPA first calculated the undiscounted commercial and recreational fishing benefits from the expected annual I&E reductions under the proposed options, based on the assumptions that all facilities in each region have achieved compliance with the rule and that benefits are realized immediately following compliance. Then, since there are regulatory and biological time lags between promulgation of the rule and the realization of benefits, EPA created a time profile of benefits that takes into account the fact that benefits do not begin immediately. The development of the time profile of benefits is discussed in detail in *Chapter A8: Discounting Benefits*.

Table E2-3 below provides the time profile of the monetary value of baseline I&E losses, by region. EPA developed similar time profiles for monetary benefits for the three proposed options for Phase III existing facilities (see Tables E2-4, E2-5, and E2-6).

Table E2-3: Time Profile of Mean Monetary Value of Total Baseline I&E Losses (thousands; 2003$)[a]

Year	California	North Atlantic	Mid-Atlantic	South Atlantic	Gulf of Mexico	Great Lakes	Inland	National Total
2007	$0	$0	$0	$0	$111	$118	$112	$341
2008	$12	$20	$111	$8	$222	$236	$224	$833
2009	$23	$41	$222	$16	$887	$945	$897	$3,031
2010	$93	$163	$889	$65	$998	$1,063	$1,009	$4,280
2011	$105	$183	$1,001	$73	$1,054	$1,122	$1,065	$4,602
2012	$110	$194	$1,056	$77	$1,109	$1,181	$1,121	$4,848
2013	$116	$204	$1,112	$81	$1,109	$1,181	$1,121	$4,924
2014	$116	$204	$1,112	$81	$1,109	$1,181	$1,121	$4,924
2015	$116	$204	$1,112	$81	$1,109	$1,181	$1,121	$4,924
2016	$116	$204	$1,112	$81	$1,109	$1,181	$1,121	$4,924
2017	$116	$204	$1,112	$81	$1,109	$1,181	$1,121	$4,924
2018	$116	$204	$1,112	$81	$1,109	$1,181	$1,121	$4,924
2019	$116	$204	$1,112	$81	$1,109	$1,181	$1,121	$4,924
2020	$116	$204	$1,112	$81	$1,109	$1,181	$1,121	$4,924
2021	$116	$204	$1,112	$81	$1,109	$1,181	$1,121	$4,924
2022	$116	$204	$1,112	$81	$1,109	$1,181	$1,121	$4,924
2023	$116	$204	$1,112	$81	$1,109	$1,181	$1,121	$4,924
2024	$116	$204	$1,112	$81	$1,109	$1,181	$1,121	$4,924
2025	$116	$204	$1,112	$81	$1,109	$1,181	$1,121	$4,924
2026	$116	$204	$1,112	$81	$1,109	$1,181	$1,121	$4,924
2027	$116	$204	$1,112	$81	$1,109	$1,181	$1,121	$4,924
2028	$116	$204	$1,112	$81	$1,109	$1,181	$1,121	$4,924
2029	$116	$204	$1,112	$81	$1,109	$1,181	$1,121	$4,924
2030	$116	$204	$1,112	$81	$1,109	$1,181	$1,121	$4,924
2031	$116	$204	$1,112	$81	$1,109	$1,181	$1,121	$4,924
2032	$116	$204	$1,112	$81	$1,109	$1,181	$1,121	$4,924
2033	$116	$204	$1,112	$81	$1,109	$1,181	$1,121	$4,924
2034	$116	$204	$1,112	$81	$1,109	$1,181	$1,121	$4,924
2035	$116	$204	$1,112	$81	$1,109	$1,181	$1,121	$4,924
2036	$116	$204	$1,112	$81	$1,109	$1,181	$1,121	$4,924
2037	$116	$204	$1,112	$81	$998	$1,063	$1,009	$4,583
2038	$105	$183	$1,001	$73	$887	$945	$897	$4,090
2039	$93	$163	$889	$65	$222	$236	$224	$1,892
2040	$23	$41	$222	$16	$111	$118	$112	$644
2041	$12	$20	$111	$8	$55	$59	$56	$322
2042	$6	$10	$56	$4	$0	$0	$0	$76
2043	$0	$0	$0	$0	$0	$0	$0	$0
2044	$0	$0	$0	$0	$0	$0	$0	$0
2045	$0	$0	$0	$0	$0	$0	$0	$0
2046	$0	$0	$0	$0	$0	$0	$0	$0
2047	$0	$0	$0	$0	$0	$0	$0	$0
2048	$0	$0	$0	$0	$0	$0	$0	$0
PV 3%[b]	**$2,143**	**$3,761**	**$20,519**	**$1,498**	**$21,088**	**$22,452**	**$21,306**	**$92,769**
Annualized 3%[c]	**$109**	**$192**	**$1,047**	**$76**	**$1,076**	**$1,146**	**$1,087**	**$4,733**
PV 7%[b]	**$1,258**	**$2,207**	**$12,042**	**$879**	**$12,857**	**$13,688**	**$12,990**	**$55,921**
Annualized 7%[c]	**$101**	**$178**	**$970**	**$71**	**$1,036**	**$1,103**	**$1,047**	**$4,506**

[a] Because EPA estimated non-use benefits only qualitatively, the total monetary value of I&E losses includes only losses in use values.

[b] The present value (PV) is estimated by discounting individual annual values to 2007, using the stated discount rate.

[c] Annualized benefits represent the value of all benefits generated over the time frame of the analysis, discounted to 2007, and then annualized over a 30-year period.

Source: U.S. EPA Analysis, 2004.

Table E2-4: Time Profile of Mean Total Use Benefits - 50 MGD All Option (thousands; 2003$)[a]

Year	California	North Atlantic	Mid-Atlantic	South Atlantic[b]	Gulf of Mexico	Great Lakes	Inland	National Total
2007	$0	$0	$0	$0	$0	$0	$0	$0
2008	$0	$0	$0	$0	$0	$0	$0	$0
2009	$0	$0	$0	$0	$0	$0	$0	$0
2010	$0	$0	$0	$0	$0	$0[e]	$7	$7
2011	$3	$0	$7	$0	$0	$11	$33	$54
2012	$7	$5	$14	$0	$76	$26	$96	$223
2013	$27	$10	$99	$0	$152	$106	$231	$625
2014	$31	$42	$164	$0	$608	$160	$275	$1,280
2015	$32	$50	$439	$0	$684	$291	$329	$1,826
2016	$34	$72	$571	$0	$722	$371	$349	$2,120
2017	$34	$78	$607	$0	$760	$391	$354	$2,225
2018	$34	$79	$636	$0	$760	$406	$358	$2,272
2019	$34	$81	$643	$0	$760	$410	$358	$2,286
2020	$34	$81	$643	$0	$760	$410	$358	$2,286
2021	$34	$81	$643	$0	$760	$410	$358	$2,286
2022	$34	$81	$643	$0	$760	$410	$358	$2,286
2023	$34	$81	$643	$0	$760	$410	$358	$2,286
2024	$34	$81	$643	$0	$760	$410	$358	$2,286
2025	$34	$81	$643	$0	$760	$410	$358	$2,286
2026	$34	$81	$643	$0	$760	$410	$358	$2,286
2027	$34	$81	$643	$0	$760	$410	$358	$2,286
2028	$34	$81	$643	$0	$760	$410	$358	$2,286
2029	$34	$81	$643	$0	$760	$410	$358	$2,286
2030	$34	$81	$643	$0	$760	$410	$358	$2,286
2031	$34	$81	$643	$0	$760	$410	$358	$2,286
2032	$34	$81	$643	$0	$760	$410	$358	$2,286
2033	$34	$81	$643	$0	$760	$410	$358	$2,286
2034	$34	$81	$643	$0	$760	$410	$358	$2,286
2035	$34	$81	$643	$0	$760	$410	$358	$2,286
2036	$34	$81	$643	$0	$760	$410	$358	$2,286
2037	$34	$81	$643	$0	$760	$410	$358	$2,286
2038	$34	$81	$643	$0	$760	$410	$358	$2,286
2039	$34	$81	$643	$0	$760	$410	$358	$2,286
2040	$34	$81	$643	$0	$760	$410	$351	$2,279
2041	$31	$81	$636	$0	$760	$400	$324	$2,232
2042	$27	$76	$629	$0	$684	$384	$262	$2,063
2043	$7	$71	$543	$0	$608	$304	$127	$1,661
2044	$3	$39	$479	$0	$152	$250	$83	$1,006
2045	$2	$31	$203	$0	$76	$120	$28	$460
2046	$0	$9	$71	$0	$38	$39	$8	$166
2047	$0	$3	$36	$0	$0	$19	$4	$61
2048	$0	$2	$7	$0	$0	$5	$0[e]	$14
PV 3%[c]	**$577**	**$1,298**	**$10,239**	**$0**	**$12,463**	**$6,602**	**$5,998**	**$37,177**
Annualized 3%[d]	**$29**	**$66**	**$522**	**$0**	**$636**	**$337**	**$306**	**$1,897**
PV 7%[c]	**$302**	**$635**	**$4,973**	**$0**	**$6,280**	**$3,252**	**$3,113**	**$18,556**
Annualized 7%[d]	**$24**	**$51**	**$401**	**$0**	**$506**	**$262**	**$251**	**$1,495**

a Because EPA estimated non-use benefits only qualitatively, the monetary value of benefits includes use values only.

b No I&E reductions are expected in the South Atlantic region because all potentially regulated facilities in this region withdraw less than 50 MGD and therefore would not be required to install technologies to comply with this option.

c The present value (PV) is estimated by discounting individual annual values to 2007, using the stated discount rate.

d Annualized benefits represent the value of all benefits generated over the time frame of the analysis, discounted to 2007, and then annualized over a 30-year period.

e Positive non-zero value less than $500.

Source: U.S. EPA Analysis, 2004.

Table E2-5: Time Profile of Mean Total Use Benefits - 200 MGD All Option (thousands; 2003$)[a]

Year	California[b]	North Atlantic	Mid-Atlantic	South Atlantic[b]	Gulf of Mexico	Great Lakes	Inland	National Total
2007	$0	$0	$0	$0	$0	$0	$0	$0
2008	$0	$0	$0	$0	$0	$0	$0	$0
2009	$0	$0	$0	$0	$0	$0	$0	$0
2010	$0	$0	$0	$0	$0	$0	$3	$3
2011	$0	$0	$0	$0	$0	$4	$23	$27
2012	$0	$0	$0	$0	$42	$8	$58	$108
2013	$0	$0	$43	$0	$83	$48	$168	$343
2014	$0	$2	$100	$0	$332	$77	$191	$702
2015	$0	$3	$372	$0	$374	$185	$225	$1,159
2016	$0	$14	$501	$0	$394	$251	$238	$1,398
2017	$0	$15	$537	$0	$415	$267	$240	$1,474
2018	$0	$16	$565	$0	$415	$279	$242	$1,518
2019	$0	$17	$572	$0	$415	$283	$242	$1,530
2020	$0	$17	$572	$0	$415	$283	$242	$1,530
2021	$0	$17	$572	$0	$415	$283	$242	$1,530
2022	$0	$17	$572	$0	$415	$283	$242	$1,530
2023	$0	$17	$572	$0	$415	$283	$242	$1,530
2024	$0	$17	$572	$0	$415	$283	$242	$1,530
2025	$0	$17	$572	$0	$415	$283	$242	$1,530
2026	$0	$17	$572	$0	$415	$283	$242	$1,530
2027	$0	$17	$572	$0	$415	$283	$242	$1,530
2028	$0	$17	$572	$0	$415	$283	$242	$1,530
2029	$0	$17	$572	$0	$415	$283	$242	$1,530
2030	$0	$17	$572	$0	$415	$283	$242	$1,530
2031	$0	$17	$572	$0	$415	$283	$242	$1,530
2032	$0	$17	$572	$0	$415	$283	$242	$1,530
2033	$0	$17	$572	$0	$415	$283	$242	$1,530
2034	$0	$17	$572	$0	$415	$283	$242	$1,530
2035	$0	$17	$572	$0	$415	$283	$242	$1,530
2036	$0	$17	$572	$0	$415	$283	$242	$1,530
2037	$0	$17	$572	$0	$415	$283	$242	$1,530
2038	$0	$17	$572	$0	$415	$283	$242	$1,530
2039	$0	$17	$572	$0	$415	$283	$242	$1,530
2040	$0	$17	$572	$0	$415	$283	$239	$1,527
2041	$0	$17	$572	$0	$415	$279	$219	$1,503
2042	$0	$17	$572	$0	$374	$275	$184	$1,422
2043	$0	$17	$529	$0	$332	$235	$74	$1,188
2044	$0	$15	$472	$0	$83	$207	$51	$828
2045	$0	$14	$200	$0	$42	$99	$17	$371
2046	$0	$3	$71	$0	$21	$32	$4	$132
2047	$0	$2	$36	$0	$0	$16	$2	$56
2048	$0	$1	$7	$0	$0	$4	$0	$12
PV 3%[c]	**$0**	**$266**	**$9,047**	**$0**	**$6,810**	**$4,513**	**$4,063**	**$24,698**
Annualized 3%[d]	**$0**	**$14**	**$462**	**$0**	**$347**	**$230**	**$207**	**$1,260**
PV 7%[c]	**$0**	**$124**	**$4,349**	**$0**	**$3,431**	**$2,192**	**$2,113**	**$12,209**
Annualized 7%[d]	**$0**	**$10**	**$350**	**$0**	**$277**	**$177**	**$170**	**$984**

[a] Because EPA estimated non-use benefits only qualitatively, the monetary value of benefits includes use values only.
[b] No I&E reductions are expected in the South Atlantic region because all potentially regulated facilities in this region withdraw less than 200 MGD and therefore would not be required to install technologies to comply with this option.
[c] The present value (PV) is estimated by discounting individual annual values to 2007, using the stated discount rate.
[d] Annualized benefits represent the value of all benefits generated over the time frame of the analysis, discounted to 2007, and then annualized over a 30-year period.

Source: U.S. EPA Analysis, 2004.

Table E2-6: Time Profile of Mean Total Use Benefits - 100 MGD CWB Option (thousands; 2003$)[a]

Year	California[b]	North Atlantic	Mid-Atlantic	South Atlantic[b]	Gulf of Mexico	Great Lakes	Inland[c]	National Total
2007	$0	$0	$0	$0	$0	$0	$0	$0
2008	$0	$0	$0	$0	$0	$0	$0	$0
2009	$0	$0	$0	$0	$0	$0	$0	$0
2010	$0	$0	$0	$0	$0	$0	$0	$0
2011	$0	$0	$0	$0	$0	$6	$0	$6
2012	$0	$5	$0	$0	$76	$12	$0	$93
2013	$0	$10	$43	$0	$152	$66	$0	$270
2014	$0	$40	$100	$0	$608	$98	$0	$846
2015	$0	$47	$372	$0	$684	$212	$0	$1,316
2016	$0	$60	$501	$0	$722	$284	$0	$1,566
2017	$0	$64	$537	$0	$760	$301	$0	$1,661
2018	$0	$65	$565	$0	$760	$314	$0	$1,703
2019	$0	$66	$572	$0	$760	$318	$0	$1,716
2020	$0	$66	$572	$0	$760	$318	$0	$1,716
2021	$0	$66	$572	$0	$760	$318	$0	$1,716
2022	$0	$66	$572	$0	$760	$318	$0	$1,716
2023	$0	$66	$572	$0	$760	$318	$0	$1,716
2024	$0	$66	$572	$0	$760	$318	$0	$1,716
2025	$0	$66	$572	$0	$760	$318	$0	$1,716
2026	$0	$66	$572	$0	$760	$318	$0	$1,716
2027	$0	$66	$572	$0	$760	$318	$0	$1,716
2028	$0	$66	$572	$0	$760	$318	$0	$1,716
2029	$0	$66	$572	$0	$760	$318	$0	$1,716
2030	$0	$66	$572	$0	$760	$318	$0	$1,716
2031	$0	$66	$572	$0	$760	$318	$0	$1,716
2032	$0	$66	$572	$0	$760	$318	$0	$1,716
2033	$0	$66	$572	$0	$760	$318	$0	$1,716
2034	$0	$66	$572	$0	$760	$318	$0	$1,716
2035	$0	$66	$572	$0	$760	$318	$0	$1,716
2036	$0	$66	$572	$0	$760	$318	$0	$1,716
2037	$0	$66	$572	$0	$760	$318	$0	$1,716
2038	$0	$66	$572	$0	$760	$318	$0	$1,716
2039	$0	$66	$572	$0	$760	$318	$0	$1,716
2040	$0	$66	$572	$0	$760	$318	$0	$1,716
2041	$0	$66	$572	$0	$760	$312	$0	$1,710
2042	$0	$61	$572	$0	$684	$306	$0	$1,623
2043	$0	$56	$529	$0	$608	$252	$0	$1,445
2044	$0	$25	$472	$0	$152	$220	$0	$870
2045	$0	$19	$200	$0	$76	$105	$0	$400
2046	$0	$6	$71	$0	$38	$34	$0	$150
2047	$0	$2	$36	$0	$0	$17	$0	$55
2048	$0	$1	$7	$0	$0	$4	$0	$12
PV 3%[d]	**$0**	**$1,059**	**$9,047**	**$0**	**$12,463**	**$5,079**	**$0**	**$27,647**
Annualized 3%[e]	**$0**	**$54**	**$462**	**$0**	**$636**	**$259**	**$0**	**$1,411**
PV 7%[d]	**$0**	**$524**	**$4,349**	**$0**	**$6,280**	**$2,479**	**$0**	**$13,632**
Annualized 7%[e]	**$0**	**$42**	**$350**	**$0**	**$506**	**$200**	**$0**	**$1,099**

[a] Because EPA estimated non-use benefits only qualitatively, the monetary value of benefits includes use values only.
[b] No I&E reductions are expected in the South Atlantic region because all potentially regulated facilities in this region withdraw less than 100 MGD and therefore would not be required to install technologies to comply with this option.
[c] The 100 MGD CWB option would not apply national categorical requirements to facilities located on freshwater rivers and lakes/reservoirs. Thus, no I&E reductions are expected at the potentially regulated facilities in the Inland region.
[d] The present value (PV) is estimated by discounting individual annual values to 2007, using the stated discount rate.
[e] Annualized benefits represent the value of all benefits generated over the time frame of the analysis, discounted to 2007, and then annualized over a 30-year period.

Source: U.S. EPA Analysis, 2004.

E2-4 TOTAL ANNUALIZED MONETARY VALUE OF LOSSES AND BENEFITS

EPA used the profiles of benefits, by region, to calculate a total present value of benefits and then to calculate a constant annual equivalent value (annualized value) of the present value. EPA performed the calculations of present value and annualized value using two discount rate values: a real rate of 3% and a real rate of 7%. Although the total period for analysis of benefits extends from 2007 through 2048, a 42-year period, EPA annualized the value of benefits over 30 years, which is the assumed length of each facility's compliance period for the social cost analysis, as described in *Chapter E1: Summary of Social Costs*. Using the same annualization period as in the cost analysis is necessary to provide a conceptually and mathematically consistent comparison of annualized benefit and cost values.

EPA estimated mean values, as well as lower and upper bound values reflecting uncertainty in the recreational benefits estimates. Table E2-7 presents the value of baseline I&E losses for each region and for the nation as a whole. Tables E2-8 and E2-9 present I&E losses for each region and the nation under the 50 MGD All, 200 MGD All, and 100 MGD CWB options discounted at 3% and 7%, respectively. Because EPA did not estimate non-use benefits quantitatively, the monetary value of national losses and benefits presented in these tables reflects only use values.[1] As described in Chapter A3 of the RBA, the Agency was not able to monetize benefits for 96.7% of the age-one equivalent losses of all commercial, recreational, and forage species analyzed for the evaluated options for existing facilities. This means that the estimates of losses and benefits presented in this section represent the losses and benefits associated with less than 3.3% of the total age-one equivalents lost due to I&E by cooling water intake structures, and should be interpreted with caution.

Table E2-7 reports the monetized value of baseline losses as outlined above. EPA estimates the national value of these losses at $0.3 million in commercial fishing losses and $4.4 million in recreational fishing losses (2003$, discounted to 2007 at 3%). The total use value of fishery resources lost is $4.7 million per year, with lower and upper bounds of $2.4 million and $9.5 million, respectively (2003$, discounted at 3%). At a 7% discount rate, EPA estimates total annual national value of losses at $0.3 million in commercial fishing losses and $4.2 million in recreational fishing losses (2003$). The total use value of fishery resources lost, discounted at 7%, is $4.5 million per year, with lower and upper bounds of $2.3 million and $9.0 million, respectively (2003$). Total monetized losses are greatest in the Great Lakes region. More detailed discussions of the valuation of recreational and commercial fishing losses under the baseline conditions in each region are provided in Parts B through G of the RBA.

[1] See Chapter A6 of the RBA for a detailed description of the ecological benefits from reduced I&E.

Table E2-7: Summary of Monetary Values of Baseline I&E Losses (thousands; 2003$)[a]

Region	Annualized Use Value of Baseline I&E Losses						
	Commercial Fishing	Recreational Fishing			Total Use Value[b]		
		Low	Mean	High	Low	Mean	High
3% discount rate							
California	$0 - $20	$38	$90	$211	$58	$109	$231
North Atlantic	$0 - $9	$84	$183	$401	$93	$192	$409
Mid-Atlantic	$0 - $47	$473	$1,000	$2,124	$520	$1,047	$2,171
South Atlantic	$0	$34	$76	$171	$34	$76	$171
Gulf of Mexico	$0 - $139	$419	$937	$2,105	$558	$1,076	$2,244
Great Lakes	$0 - $70	$534	$1,076	$2,109	$604	$1,146	$2,179
Inland[c]	n/a	$576	$1,087	$2,047	$576	$1,087	$2,047
National Total	**$0 - $284**	**$2,159**	**$4,449**	**$9,168**	**$2,443**	**$4,733**	**$9,452**
7% discount rate							
California	$0 - $18	$35	$83	$196	$54	$101	$214
North Atlantic	$0 - $8	$78	$170	$371	$86	$178	$379
Mid-Atlantic	$0 - $44	$438	$927	$1,969	$482	$970	$2,012
South Atlantic	$0	$32	$71	$158	$32	$71	$158
Gulf of Mexico	$0 - $133	$404	$903	$2,028	$537	$1,036	$2,161
Great Lakes	$0 - $67	$515	$1,036	$2,031	$582	$1,103	$2,099
Inland[c]	n/a	$555	$1,047	$1,971	$555	$1,047	$1,971
National Total	**$0 - $271**	**$2,057**	**$4,236**	**$8,724**	**$2,328**	**$4,506**	**$8,995**

[a] All losses presented in this table are annualized. These estimated annualized losses represent the value of all losses generated over the time frame of the analysis, discounted to 2007, and then annualized over a 30-year period.

[b] The total monetizable value of I&E reductions includes use benefits only. EPA evaluated non-use benefits only qualitatively. A range of recreational fishing benefits is provided, based on the Krinsky and Robb technique to estimated the 95th and 5th percentile limits on the marginal value per fish predicted by EPA's meta-analysis (see chapter A5 of the RBA). Commercial fishing benefits are computed based on a range from 0% to 40% of the change in gross revenue (see Chapter A4 of the RBA). To calculate the total use value columns (low, mean, and high), the high end value for commercial fishing benefits is added to the low, mean, and high values for recreational fishing benefits, respectively.

[c] No significant commercial fishing takes place in the Inland region. Thus, this region is excluded from the commercial fishing analysis.

Source: U.S. EPA Analysis, 2004.

Tables E2-8 and E2-9 present EPA's estimates of the national and regional values of avoided I&E losses (all values are in 2003$, discounted at 3% and 7% to beginning of year 2007, and annualized over a 30-year period). National values of avoided I&E losses at a 3% discount rate are as follows:

- For the 50 MGD All option, a mean value of $1.9 million per year, with lower and upper bounds of $1.0 million and $3.8 million (see Table E2-8);

- For the 200 MGD All option, a mean value of $1.3 million per year, with lower and upper bounds of $0.6 million and $2.5 million (see Table E2-8); and

- For the 100 MGD CWB option, a mean value of $1.4 million per year, with lower and upper bounds of $0.7 million and $2.9 million (see Table E2-8).

The 7% discount rate calculations yield smaller values as follows:

- For the 50 MGD All option, a mean value of $1.5 million per year, with lower and upper bounds of $0.8 million and $3.0 million (see Table E2-9);

- For the 200 MGD All option, a mean value of $1.0 million per year, with lower and upper bounds of $0.5 million and $2.0 million (see Table E2-9); and

- For the 100 MGD CWB option, a mean value of $1.1 million per year, with lower and upper bounds of $0.6 million and $2.3 million (see Table E2-9).

EPA also considered how benefits might increase if facilities that meet technology requirements in the baseline optimize their operation and maintenance (O&M) procedures (e.g., by rotating screens more often to reduce impingement mortality due to the proposed regulation). For this analysis, EPA evaluated facilities that are expected to (1) install no new technology and (2) meet impingement standards with a 0.5 fps screen. If there was a 5% increase in the efficacy of O&M at these facilities, the total annualized national benefits from the proposed regulation would increase by approximately $19,000 for the 50 MGD All option, from $1.897 million to $1.916 million (using the 3% discount rate). If there was a 15% increase in efficacy, the estimated annualized benefits would increase by over $58,000, to $1.955 million (using the 3% discount rate). Using the 7% discount rate, total annualized national benefits from the proposed regulation would increase by approximately $18,000 and $55,000, for the 5% and 15% increases in efficacy, respectively. Therefore, optimization of O&M procedures would result in 1.0% to 3.5% increase in the estimated total use benefits of the proposed regulation, depending on the assumed increase in efficacy and the discount rate being used. Optimization of O&M procedures would result in similar increases in the estimated use benefits under “200 MGD for All Waterbodies” and “100 MGD for Certain Waterbodies” options.

The majority of the use benefit value is attributable to benefits to recreational anglers from improved catch rates. As shown in Tables E2-8 and E2-9, use benefits are largest in the Gulf of Mexico for the 50 MGD All and 100 MGD CWB options and the Mid-Atlantic region under the 200 MGD All option. More detailed discussions of regional benefits under each option are provided in Parts B through G of the RBA.

Table E2-8: Summary of Monetized Benefits by Option (thousands; 2003$; discounted at 3%)[a]

Region	Annualized Commercial Fishing Benefits	Annualized Recreational Fishing Benefits			Total Annualized Value of Monetized Impingement and Entrainment Reductions[b]		
		Low	Mean	High	Low	Mean	High
50 MGD All Option							
California	$0 - $5	$10	$24	$57	$16	$29	$62
North Atlantic	$0 - $3	$29	$63	$138	$32	$66	$141
Mid-Atlantic	$0 - $25	$235	$497	$1,057	$260	$522	$1,082
South Atlantic[c]	$0	$0	$0	$0	$0	$0	$0
Gulf of Mexico	$0 - $78	$249	$558	$1,254	$327	$636	$1,332
Great Lakes	$0 - $20	$157	$316	$621	$178	$337	$641
Inland[d]	n/a	$162	$306	$577	$162	$306	$577
National Total	**$0 - $132**	**$843**	**$1,765**	**$3,704**	**$975**	**$1,897**	**$3,836**
200 MGD All Option							
California[e]	$0	$0	$0	$0	$0	$0	$0
North Atlantic	$0 - $1	$6	$13	$28	$7	$14	$29
Mid-Atlantic	$0 - $22	$208	$440	$934	$230	$462	$956
South Atlantic[c]	$0	$0	$0	$0	$0	$0	$0
Gulf of Mexico	$0 - $43	$136	$305	$685	$179	$347	$728
Great Lakes	$0 - $14	$108	$216	$425	$122	$230	$439
Inland[d]	n/a	$110	$207	$390	$110	$207	$390
National Total	**$0 - $79**	**$567**	**$1,181**	**$2,463**	**$647**	**$1,260**	**$2,542**
100 MGD CWB Option							
California[e]	$0	$0	$0	$0	$0	$0	$0
North Atlantic	$0 - $2	$24	$52	$113	$26	$54	$115
Mid-Atlantic	$0 - $22	$208	$440	$934	$230	$462	$956
South Atlantic[c]	$0	$0	$0	$0	$0	$0	$0
Gulf of Mexico	$0 - $78	$249	$558	$1,254	$327	$636	$1,332
Great Lakes	$0 - $16	$121	$243	$478	$137	$259	$494
Inland[d,f]	n/a	$0	$0	$0	$0	$0	$0
National Total	**$0 - $118**	**$602**	**$1,292**	**$2,779**	**$720**	**$1,411**	**$2,897**

[a] All benefits presented in this table are annualized. These annualized benefits represent the value of all losses generated over the time frame of the analysis, discounted to 2007, and then annualized over a 30-year period.

[b] The total monetizable value of I&E reductions includes use benefits only. EPA evaluated non-use benefits only qualitatively. A range of recreational fishing benefits is provided, based on the Krinsky and Robb technique to estimated the 95th and 5th percentile limits on the marginal value per fish predicted by EPA's meta-analysis (see chapter A5 of the RBA). Commercial fishing benefits are computed based on a range from 0% to 40% of the change in gross revenue (see Chapter A4 of the RBA). To calculate the total use value columns (low, mean, and high), the high end value for commercial fishing benefits is added to the low, mean, and high values for recreational fishing benefits, respectively.

[c] No I&E reductions are expected in the South Atlantic region because all potentially regulated facilities in this region withdraw less than 50 MGD and therefore would not be required to install technologies to comply with the proposed options.

[d] No significant commercial fishing takes place in the Inland region. Thus, this region is excluded from the commercial fishing analysis.

[e] No I&E reductions are expected in the California region because all potentially regulated facilities in this region withdraw less than 100 MGD and therefore would not be required to install technologies to comply with the 200 MGD All and the 100 MGD CWB options.

[f] The 100 MGD CWB option would not apply national categorical requirements to facilities located on freshwater rivers and lakes/reservoirs. Thus, no I&E reductions are expected at the potentially regulated facilities in the Inland region.

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

Table E2-9: Summary of Monetized Benefits by Option (thousands; 2003$; discounted at 7%)[a]

Region	Annualized Commercial Fishing Benefits	Annualized Recreational Fishing Benefits			Total Annualized Value of Monetized Impingement and Entrainment Reductions[b]		
		Low	Mean	High	Low	Mean	High
50 MGD All Option							
California	$0 - $4	$9	$20	$47	$13	$24	$51
North Atlantic	$0 - $2	$22	$49	$107	$25	$51	$109
Mid-Atlantic	$0 - $19	$181	$382	$811	$200	$401	$830
South Atlantic[c]	$0	$0	$0	$0	$0	$0	$0
Gulf of Mexico	$0 - $62	$198	$444	$998	$260	$506	$1,061
Great Lakes	$0 - $16	$122	$246	$483	$138	$262	$499
Inland[d]	n/a	$133	$251	$473	$133	$251	$473
National Total	$0 - $104	$665	$1,391	$2,919	$769	$1,495	$3,023
200 MGD All Option							
California[e]	$0	$0	$0	$0	$0	$0	$0
North Atlantic	$0	$4	$10	$21	$5	$10	$21
Mid-Atlantic	$0 - $17	$158	$334	$709	$175	$350	$726
South Atlantic[c]	$0	$0	$0	$0	$0	$0	$0
Gulf of Mexico	$0 - $34	$108	$243	$545	$142	$277	$579
Great Lakes	$0 - $11	$83	$166	$326	$93	$177	$337
Inland[d]	n/a	$90	$170	$321	$90	$170	$321
National Total	$0 - $62	$443	$922	$1,922	$505	$984	$1,984
100 MGD CWB Option							
California[e]	$0	$0	$0	$0	$0	$0	$0
North Atlantic	$0 - $2	$19	$40	$88	$20	$42	$90
Mid-Atlantic	$0 - $17	$158	$334	$709	$175	$350	$726
South Atlantic[c]	$0	$0	$0	$0	$0	$0	$0
Gulf of Mexico	$0 - $62	$198	$444	$998	$260	$506	$1,061
Great Lakes	$0 - $12	$93	$188	$368	$105	$200	$381
Inland[d,f]	n/a	$0	$0	$0	$0	$0	$0
National Total	$0 - $93	$468	$1,006	$2,164	$561	$1,099	$2,257

[a] All benefits presented in this table are annualized. These annualized benefits represent the value of all losses generated over the time frame of the analysis, discounted to 2007, and then annualized over a 30-year period.

[b] The total monetizable value of I&E reductions includes use benefits only. EPA evaluated non-use benefits only qualitatively. A range of recreational fishing benefits is provided, based on the Krinsky and Robb technique to estimated the 95th and 5th percentile limits on the marginal value per fish predicted by EPA's meta-analysis (see chapter A5 of the RBA). Commercial fishing benefits are computed based on a range from 0% to 40% of the change in gross revenue (see Chapter A4 of the RBA). To calculate the total use value columns (low, mean, and high), the high end value for commercial fishing benefits is added to the low, mean, and high values for recreational fishing benefits, respectively.

[c] No I&E reductions are expected in the South Atlantic region because all potentially regulated facilities in this region withdraw less than 50 MGD and therefore would not be required to install technologies to comply with the proposed options.

[d] No significant commercial fishing takes place in the Inland region, and thus this region is excluded from the commercial fishing benefits analysis.

[e] No I&E reductions are expected in the California region because all potentially regulated facilities in this region withdraw less than 100 MGD and therefore would not be required to install technologies to comply with the 200 MGD All and the 100 MGD CWB options.

[f] The 100 MGD CWB option would not apply national categorical requirements to facilities located on freshwater rivers and lakes/reservoirs. Thus, no I&E reductions are expected at the potentially regulated facilities in the Inland region.

Source: U.S. EPA Analysis, 2004.

REFERENCES

U.S. Environmental Protection Agency (U.S. EPA). 2004. *The Regional Benefits Assessment for the Proposed Section 316(b) Rule for Phase III Facilities*. EPA-821-R-04-017. November 2004.

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Appendix to Chapter E2

INTRODUCTION

APPENDIX CONTENTS

This appendix supplements Chapter E2 by presenting the results of the benefits analysis for five other options evaluated for potential Phase III existing facilities. For all options, facility counts and other results only include those potential Phase III existing facilities that are (1) non-baseline closures and (2) subject to national categorical requirements under the option. The options are presented in increasing order based on design intake flow (DIF) applicability threshold and the stringency of compliance requirements. See the main body of this chapter for a description of methodologies used in this analysis.

E2A-1 SUMMARY OF EXPECTED REDUCTIONS IN I&E

Table E2A-1 presents the number of facilities with technology requirements under the other options, by region, and EPA's estimates of the percentage by which I&E would be reduced. The table also presents estimates of regional and national reductions in I&E losses under each option, expressed as age-one equivalents lost and foregone fishery yield.

Table E2A-1: Expected Reductions in I&E for Existing Phase III Facilities by Option

Region	Number of Facilities Installing Technology	Impingement	Entrainment	Age-One Equivalents (thousands)	Foregone Fishery Yield (thousands; lbs)
Option 3					
California	4	78%	29%	391	28
North Atlantic	4	43%	40%	930	18
Mid-Atlantic	4	74%	55%	13,400	606
South Atlantic[a]	0	0%	0%	0	0
Gulf of Mexico	11	80%	57%	8,650	1,270
Great Lakes	38	38%	43%	13,200	190
Inland	130	43%	27%	16,600	171
National Total	**190**			**53,171**	**2,283**
Option 4					
California	4	78%	59%	771	56
North Atlantic	4	43%	40%	930	18
Mid-Atlantic	4	74%	55%	13,600	610
South Atlantic[a]	0	0%	0%	0	0
Gulf of Mexico	11	80%	60%	8,860	1,320
Great Lakes	38	38%	46%	13,300	192
Inland	69	37%	27%	14,800	157
National Total	**130**			**52,261**	**2,353**
Option 2					

Table E2A-1: Expected Reductions in I&E for Existing Phase III Facilities by Option

Region	Number of Facilities Installing Technology	Impingement	Entrainment	Age-One Equivalents (thousands)	Foregone Fishery Yield (thousands; lbs)
California	4	78%	59%	771	56
North Atlantic	4	43%	40%	930	18
Mid-Atlantic	4	74%	55%	13,600	610
South Atlantic[a]	0	0%	0%	0	0
Gulf of Mexico	11	80%	60%	8,860	1,320
Great Lakes	38	38%	46%	13,300	192
Inland	69	37%	27%	14,800	157
National Total	**130**			**52,261**	**2,353**
		Option 1			
California	4	78%	59%	771	56
North Atlantic	4	43%	40%	930	18
Mid-Atlantic	4	74%	55%	13,600	610
South Atlantic[a]	0	0%	0%	0	0
Gulf of Mexico	11	80%	60%	8,860	1,320
Great Lakes	38	38%	46%	13,300	192
Inland	134	43%	29%	16,900	177
National Total	**194**			**54,361**	**2,373**
		Option 6			
California	4	78%	59%	771	56
North Atlantic	4	43%	40%	930	18
Mid-Atlantic	5	75%	56%	13,700	615
South Atlantic[a]	0	0%	0%	0	0
Gulf of Mexico	11	80%	60%	8,860	1,320
Great Lakes	61	41%	48%	14,300	206
Inland	203	45%	30%	17,600	183
National Total	**288**			**56,161**	**2,398**

[a] No I&E reductions are expected in the South Atlantic region because all potentially regulated facilities in this region already meet the national categorical requirements in the baseline and therefore would not be required to install technologies to comply with these options.

Source: U.S. EPA Analysis, 2004.

E2A-2 TIME PROFILE OF BENEFITS

Tables E2A-2 through E2A-6 below provide the time profiles of regional benefits for Option 3, Option 4, Option 2, Option 1, and Option 6.

Table E2A-2: Time Profile of Mean Total Use Benefits - Option 3 (thousands; 2003$)[a]

Year	California	North Atlantic	Mid-Atlantic	South Atlantic[b]	Gulf of Mexico	Great Lakes	Inland	National Total
2007	$0	$0	$0	$0	$0	$0	$0	$0
2008	$0	$0	$0	$0	$0	$0	$0	$0
2009	$0	$0	$0	$0	$0	$0	$0	$0
2010	$0	$0	$0	$0	$0	$0[e]	$7	$8
2011	$2	$0	$7	$0	$0	$12	$34	$55
2012	$4	$5	$15	$0	$79	$31	$101	$234
2013	$14	$10	$100	$0	$158	$121	$238	$641
2014	$18	$42	$170	$0	$631	$193	$292	$1,346
2015	$20	$50	$443	$0	$710	$331	$354	$1,909
2016	$32	$72	$574	$0	$750	$418	$380	$2,226
2017	$34	$78	$610	$0	$789	$440	$387	$2,338
2018	$35	$79	$638	$0	$789	$455	$391	$2,387
2019	$36	$81	$645	$0	$789	$460	$391	$2,403
2020	$36	$81	$645	$0	$789	$460	$391	$2,403
2021	$36	$81	$645	$0	$789	$460	$391	$2,403
2022	$36	$81	$645	$0	$789	$460	$391	$2,403
2023	$36	$81	$645	$0	$789	$460	$391	$2,403
2024	$36	$81	$645	$0	$789	$460	$391	$2,403
2025	$36	$81	$645	$0	$789	$460	$391	$2,403
2026	$36	$81	$645	$0	$789	$460	$391	$2,403
2027	$36	$81	$645	$0	$789	$460	$391	$2,403
2028	$36	$81	$645	$0	$789	$460	$391	$2,403
2029	$36	$81	$645	$0	$789	$460	$391	$2,403
2030	$36	$81	$645	$0	$789	$460	$391	$2,403
2031	$36	$81	$645	$0	$789	$460	$391	$2,403
2032	$36	$81	$645	$0	$789	$460	$391	$2,403
2033	$36	$81	$645	$0	$789	$460	$391	$2,403
2034	$36	$81	$645	$0	$789	$460	$391	$2,403
2035	$36	$81	$645	$0	$789	$460	$391	$2,403
2036	$36	$81	$645	$0	$789	$460	$391	$2,403
2037	$36	$81	$645	$0	$789	$460	$391	$2,403
2038	$36	$81	$645	$0	$789	$460	$391	$2,403
2039	$36	$81	$645	$0	$789	$460	$391	$2,403
2040	$36	$81	$645	$0	$789	$460	$384	$2,395
2041	$34	$81	$638	$0	$789	$448	$357	$2,348
2042	$32	$76	$630	$0	$710	$429	$291	$2,169
2043	$21	$71	$545	$0	$631	$339	$153	$1,762
2044	$18	$39	$475	$0	$158	$267	$99	$1,057
2045	$15	$31	$202	$0	$79	$129	$37	$493
2046	$4	$9	$71	$0	$39	$42	$11	$176
2047	$2	$3	$35	$0	$0	$20	$5	$65
2048	$1	$2	$7	$0	$0	$5	$1	$15
PV 3%[c]	**$574**	**$1,298**	**$10,281**	**$0**	**$12,945**	**$7,416**	**$6,542**	**$39,056**
Annualized 3%[d]	**$29**	**$66**	**$525**	**$0**	**$660**	**$378**	**$334**	**$1,993**
PV 7%[c]	**$285**	**$635**	**$4,996**	**$0**	**$6,523**	**$3,661**	**$3,384**	**$19,484**
Annualized 7%[d]	**$23**	**$51**	**$403**	**$0**	**$526**	**$295**	**$273**	**$1,570**

[a] Because EPA estimated non-use benefits only qualitatively, the monetary value of benefits includes use values only.

[b] No I&E reductions are expected in the South Atlantic region because all potentially regulated facilities in this region already meet the national categorical requirements in the baseline and therefore would not be required to install technologies to comply with this option.

[c] The present value (PV) is estimated by discounting individual annual values to 2007, using the stated discount rate.

[d] Annualized benefits represent the value of all benefits generated over the time frame of the analysis, discounted to 2007, and then annualized over a 30-year period.

[e] Positive non-zero value less than $500.

Source: U.S. EPA Analysis, 2004.

Table E2A-3: Time Profile of Mean Total Use Benefits - Option 4 (thousands; 2003$)[a]

Year	California	North Atlantic	Mid-Atlantic	South Atlantic[b]	Gulf of Mexico	Great Lakes	Inland	National Total
2007	$0	$0	$0	$0	$0	$0	$0	$0
2008	$0	$0	$0	$0	$0	$0	$0	$0
2009	$0	$0	$0	$0	$0	$0	$0	$0
2010	$0	$0	$0	$0	$0	$1	$7	$7
2011	$3	$0	$7	$0	$0	$12	$33	$56
2012	$7	$5	$15	$0	$80	$31	$96	$234
2013	$27	$10	$101	$0	$161	$122	$231	$652
2014	$34	$42	$172	$0	$642	$195	$275	$1,360
2015	$39	$50	$449	$0	$723	$334	$329	$1,924
2016	$62	$72	$581	$0	$763	$422	$349	$2,250
2017	$65	$78	$617	$0	$803	$445	$354	$2,362
2018	$67	$79	$646	$0	$803	$460	$358	$2,413
2019	$69	$81	$653	$0	$803	$465	$358	$2,428
2020	$69	$81	$653	$0	$803	$465	$358	$2,428
2021	$69	$81	$653	$0	$803	$465	$358	$2,428
2022	$69	$81	$653	$0	$803	$465	$358	$2,428
2023	$69	$81	$653	$0	$803	$465	$358	$2,428
2024	$69	$81	$653	$0	$803	$465	$358	$2,428
2025	$69	$81	$653	$0	$803	$465	$358	$2,428
2026	$69	$81	$653	$0	$803	$465	$358	$2,428
2027	$69	$81	$653	$0	$803	$465	$358	$2,428
2028	$69	$81	$653	$0	$803	$465	$358	$2,428
2029	$69	$81	$653	$0	$803	$465	$358	$2,428
2030	$69	$81	$653	$0	$803	$465	$358	$2,428
2031	$69	$81	$653	$0	$803	$465	$358	$2,428
2032	$69	$81	$653	$0	$803	$465	$358	$2,428
2033	$69	$81	$653	$0	$803	$465	$358	$2,428
2034	$69	$81	$653	$0	$803	$465	$358	$2,428
2035	$69	$81	$653	$0	$803	$465	$358	$2,428
2036	$69	$81	$653	$0	$803	$465	$358	$2,428
2037	$69	$81	$653	$0	$803	$465	$358	$2,428
2038	$69	$81	$653	$0	$803	$465	$358	$2,428
2039	$69	$81	$653	$0	$803	$465	$358	$2,428
2040	$69	$81	$653	$0	$803	$464	$351	$2,421
2041	$65	$81	$646	$0	$803	$453	$324	$2,373
2042	$62	$76	$638	$0	$723	$434	$262	$2,195
2043	$41	$71	$552	$0	$642	$343	$127	$1,776
2044	$35	$39	$481	$0	$161	$270	$83	$1,068
2045	$29	$31	$205	$0	$80	$131	$28	$504
2046	$7	$9	$72	$0	$40	$42	$8	$179
2047	$3	$3	$36	$0	$0	$20	$4	$66
2048	$2	$2	$7	$0	$0	$5	$0[e]	$16
PV 3%[c]	**$1,112**	**$1,298**	**$10,407**	**$0**	**$13,167**	**$7,494**	**$5,998**	**$39,475**
Annualized 3%[d]	**$57**	**$66**	**$531**	**$0**	**$672**	**$382**	**$306**	**$2,014**
PV 7%[c]	**$552**	**$635**	**$5,057**	**$0**	**$6,635**	**$3,699**	**$3,113**	**$19,692**
Annualized 7%[d]	**$44**	**$51**	**$408**	**$0**	**$535**	**$298**	**$251**	**$1,587**

a Because EPA estimated non-use benefits only qualitatively, the monetary value of benefits includes use values only.

b No I&E reductions are expected in the South Atlantic region because all potentially regulated facilities in this region already meet the national categorical requirements in the baseline and therefore would not be required to install technologies to comply with this option.

c The present value (PV) is estimated by discounting individual annual values to 2007, using the stated discount rate.

d Annualized benefits represent the value of all benefits generated over the time frame of the analysis, discounted to 2007, and then annualized over a 30-year period.

e Positive non-zero value less than $500.

Source: U.S. EPA Analysis, 2004.

Table E2A-4: Time Profile of Mean Total Use Benefits - Option 2 (thousands; 2003$)[a]

Year	California	North Atlantic	Mid-Atlantic	South Atlantic[b]	Gulf of Mexico	Great Lakes	Inland	National Total
2007	$0	$0	$0	$0	$0	$0	$0	$0
2008	$0	$0	$0	$0	$0	$0	$0	$0
2009	$0	$0	$0	$0	$0	$0	$0	$0
2010	$0	$0	$0	$0	$0	$1	$7	$7
2011	$3	$0	$7	$0	$0	$12	$33	$56
2012	$7	$5	$15	$0	$80	$31	$96	$234
2013	$27	$10	$101	$0	$161	$122	$231	$652
2014	$34	$42	$172	$0	$642	$195	$275	$1,360
2015	$39	$50	$449	$0	$723	$334	$329	$1,924
2016	$62	$72	$581	$0	$763	$422	$349	$2,250
2017	$65	$78	$617	$0	$803	$445	$354	$2,362
2018	$67	$79	$646	$0	$803	$460	$358	$2,413
2019	$69	$81	$653	$0	$803	$465	$358	$2,428
2020	$69	$81	$653	$0	$803	$465	$358	$2,428
2021	$69	$81	$653	$0	$803	$465	$358	$2,428
2022	$69	$81	$653	$0	$803	$465	$358	$2,428
2023	$69	$81	$653	$0	$803	$465	$358	$2,428
2024	$69	$81	$653	$0	$803	$465	$358	$2,428
2025	$69	$81	$653	$0	$803	$465	$358	$2,428
2026	$69	$81	$653	$0	$803	$465	$358	$2,428
2027	$69	$81	$653	$0	$803	$465	$358	$2,428
2028	$69	$81	$653	$0	$803	$465	$358	$2,428
2029	$69	$81	$653	$0	$803	$465	$358	$2,428
2030	$69	$81	$653	$0	$803	$465	$358	$2,428
2031	$69	$81	$653	$0	$803	$465	$358	$2,428
2032	$69	$81	$653	$0	$803	$465	$358	$2,428
2033	$69	$81	$653	$0	$803	$465	$358	$2,428
2034	$69	$81	$653	$0	$803	$465	$358	$2,428
2035	$69	$81	$653	$0	$803	$465	$358	$2,428
2036	$69	$81	$653	$0	$803	$465	$358	$2,428
2037	$69	$81	$653	$0	$803	$465	$358	$2,428
2038	$69	$81	$653	$0	$803	$465	$358	$2,428
2039	$69	$81	$653	$0	$803	$465	$358	$2,428
2040	$69	$81	$653	$0	$803	$464	$351	$2,421
2041	$65	$81	$646	$0	$803	$453	$324	$2,373
2042	$62	$76	$638	$0	$723	$434	$262	$2,195
2043	$41	$71	$552	$0	$642	$343	$127	$1,776
2044	$35	$39	$481	$0	$161	$270	$83	$1,068
2045	$29	$31	$205	$0	$80	$131	$28	$504
2046	$7	$9	$72	$0	$40	$42	$8	$179
2047	$3	$3	$36	$0	$0	$20	$4	$66
2048	$2	$2	$7	$0	$0	$5	$0[e]	$16
PV 3%[c]	**$1,112**	**$1,298**	**$10,407**	**$0**	**$13,167**	**$7,494**	**$5,998**	**$39,475**
Annualized 3%[d]	**$57**	**$66**	**$531**	**$0**	**$672**	**$382**	**$306**	**$2,014**
PV 7%[c]	**$552**	**$635**	**$5,057**	**$0**	**$6,635**	**$3,699**	**$3,113**	**$19,692**
Annualized 7%[d]	**$44**	**$51**	**$408**	**$0**	**$535**	**$298**	**$251**	**$1,587**

[a] Because EPA estimated non-use benefits only qualitatively, the monetary value of benefits includes use values only.

[b] No I&E reductions are expected in the South Atlantic region because all potentially regulated facilities in this region already meet the national categorical requirements in the baseline and therefore would not be required to install technologies to comply with this option.

[c] The present value (PV) is estimated by discounting individual annual values to 2007, using the stated discount rate.

[d] Annualized benefits represent the value of all benefits generated over the time frame of the analysis, discounted to 2007, and then annualized over a 30-year period.

[e] Positive non-zero value less than $500.

Source: U.S. EPA Analysis, 2004.

Table E2A-5: Time Profile of Mean Total Use Benefits - Option 1 (thousands; 2003$)[a]

Year	California	North Atlantic	Mid-Atlantic	South Atlantic[b]	Gulf of Mexico	Great Lakes	Inland	National Total
2007	$0	$0	$0	$0	$0	$0	$0	$0
2008	$0	$0	$0	$0	$0	$0	$0	$0
2009	$0	$0	$0	$0	$0	$0	$0	$0
2010	$0	$0	$0	$0	$0	$1	$7	$8
2011	$3	$0	$7	$0	$0	$12	$35	$57
2012	$7	$5	$15	$0	$80	$31	$104	$242
2013	$27	$10	$101	$0	$161	$122	$245	$666
2014	$34	$42	$172	$0	$642	$195	$302	$1,387
2015	$39	$50	$449	$0	$723	$334	$366	$1,961
2016	$62	$72	$581	$0	$763	$422	$392	$2,292
2017	$65	$78	$617	$0	$803	$445	$399	$2,407
2018	$67	$79	$646	$0	$803	$460	$403	$2,458
2019	$69	$81	$653	$0	$803	$465	$404	$2,474
2020	$69	$81	$653	$0	$803	$465	$404	$2,474
2021	$69	$81	$653	$0	$803	$465	$404	$2,474
2022	$69	$81	$653	$0	$803	$465	$404	$2,474
2023	$69	$81	$653	$0	$803	$465	$404	$2,474
2024	$69	$81	$653	$0	$803	$465	$404	$2,474
2025	$69	$81	$653	$0	$803	$465	$404	$2,474
2026	$69	$81	$653	$0	$803	$465	$404	$2,474
2027	$69	$81	$653	$0	$803	$465	$404	$2,474
2028	$69	$81	$653	$0	$803	$465	$404	$2,474
2029	$69	$81	$653	$0	$803	$465	$404	$2,474
2030	$69	$81	$653	$0	$803	$465	$404	$2,474
2031	$69	$81	$653	$0	$803	$465	$404	$2,474
2032	$69	$81	$653	$0	$803	$465	$404	$2,474
2033	$69	$81	$653	$0	$803	$465	$404	$2,474
2034	$69	$81	$653	$0	$803	$465	$404	$2,474
2035	$69	$81	$653	$0	$803	$465	$404	$2,474
2036	$69	$81	$653	$0	$803	$465	$404	$2,474
2037	$69	$81	$653	$0	$803	$465	$404	$2,474
2038	$69	$81	$653	$0	$803	$465	$404	$2,474
2039	$69	$81	$653	$0	$803	$465	$404	$2,474
2040	$69	$81	$653	$0	$803	$464	$396	$2,467
2041	$65	$81	$646	$0	$803	$453	$369	$2,417
2042	$62	$76	$638	$0	$723	$434	$300	$2,232
2043	$41	$71	$552	$0	$642	$343	$159	$1,809
2044	$35	$39	$481	$0	$161	$270	$102	$1,087
2045	$29	$31	$205	$0	$80	$131	$38	$514
2046	$7	$9	$72	$0	$40	$42	$12	$182
2047	$3	$3	$36	$0	$0	$20	$5	$67
2048	$2	$2	$7	$0	$0	$5	$1	$16
PV 3%[c]	**$1,112**	**$1,298**	**$10,407**	**$0**	**$13,167**	**$7,494**	**$6,748**	**$40,225**
Annualized 3%[d]	**$57**	**$66**	**$531**	**$0**	**$672**	**$382**	**$344**	**$2,052**
PV 7%[c]	**$552**	**$635**	**$5,057**	**$0**	**$6,635**	**$3,699**	**$3,490**	**$20,068**
Annualized 7%[d]	**$44**	**$51**	**$408**	**$0**	**$535**	**$298**	**$281**	**$1,617**

[a] Because EPA estimated non-use benefits only qualitatively, the monetary value of benefits includes use values only.

[b] No I&E reductions are expected in the South Atlantic region because all potentially regulated facilities in this region already meet the national categorical requirements in the baseline and therefore would not be required to install technologies to comply with this option.

[c] The present value (PV) is estimated by discounting individual annual values to 2007, using the stated discount rate.

[d] Annualized benefits represent the value of all benefits generated over the time frame of the analysis, discounted to 2007, and then annualized over a 30-year period.

Source: U.S. EPA Analysis, 2004.

Table E2A-6: Time Profile of Mean Total Use Benefits - Option 6 (thousands; 2003$)[a]

Year	California	North Atlantic	Mid-Atlantic	South Atlantic[b]	Gulf of Mexico	Great Lakes	Inland	National Total
2007	$0	$0	$0	$0	$0	$0	$0	$0
2008	$0	$0	$0	$0	$0	$0	$0	$0
2009	$0	$0	$0	$0	$0	$0	$0	$0
2010	$0	$0	$0	$0	$0	$1	$8	$9
2011	$3	$0	$7	$0	$0	$15	$36	$61
2012	$7	$5	$15	$0	$80	$41	$106	$254
2013	$27	$10	$101	$0	$161	$140	$251	$690
2014	$34	$42	$172	$0	$642	$216	$311	$1,418
2015	$39	$50	$449	$0	$723	$361	$377	$1,999
2016	$62	$72	$582	$0	$763	$455	$406	$2,340
2017	$65	$78	$622	$0	$803	$478	$413	$2,460
2018	$67	$79	$651	$0	$803	$494	$418	$2,512
2019	$69	$81	$659	$0	$803	$499	$419	$2,529
2020	$69	$81	$659	$0	$803	$499	$419	$2,529
2021	$69	$81	$659	$0	$803	$499	$419	$2,529
2022	$69	$81	$659	$0	$803	$499	$419	$2,529
2023	$69	$81	$659	$0	$803	$499	$419	$2,529
2024	$69	$81	$659	$0	$803	$499	$419	$2,529
2025	$69	$81	$659	$0	$803	$499	$419	$2,529
2026	$69	$81	$659	$0	$803	$499	$419	$2,529
2027	$69	$81	$659	$0	$803	$499	$419	$2,529
2028	$69	$81	$659	$0	$803	$499	$419	$2,529
2029	$69	$81	$659	$0	$803	$499	$419	$2,529
2030	$69	$81	$659	$0	$803	$499	$419	$2,529
2031	$69	$81	$659	$0	$803	$499	$419	$2,529
2032	$69	$81	$659	$0	$803	$499	$419	$2,529
2033	$69	$81	$659	$0	$803	$499	$419	$2,529
2034	$69	$81	$659	$0	$803	$499	$419	$2,529
2035	$69	$81	$659	$0	$803	$499	$419	$2,529
2036	$69	$81	$659	$0	$803	$499	$419	$2,529
2037	$69	$81	$659	$0	$803	$499	$419	$2,529
2038	$69	$81	$659	$0	$803	$499	$419	$2,529
2039	$69	$81	$659	$0	$803	$499	$419	$2,529
2040	$69	$81	$659	$0	$803	$498	$411	$2,520
2041	$65	$81	$652	$0	$803	$484	$383	$2,468
2042	$62	$76	$644	$0	$723	$458	$312	$2,275
2043	$41	$71	$557	$0	$642	$359	$168	$1,839
2044	$35	$39	$487	$0	$161	$283	$107	$1,112
2045	$29	$31	$210	$0	$80	$138	$41	$530
2046	$7	$9	$77	$0	$40	$45	$13	$190
2047	$3	$3	$37	$0	$0	$21	$5	$70
2048	$2	$2	$8	$0	$0	$5	$1	$17
PV 3%[c]	**$1,112**	**$1,298**	**$10,492**	**$0**	**$13,167**	**$8,063**	**$6,993**	**$41,124**
Annualized 3%[d]	**$57**	**$66**	**$535**	**$0**	**$672**	**$411**	**$357**	**$2,098**
PV 7%[c]	**$552**	**$635**	**$5,095**	**$0**	**$6,635**	**$3,990**	**$3,614**	**$20,521**
Annualized 7%[d]	**$44**	**$51**	**$411**	**$0**	**$535**	**$322**	**$291**	**$1,654**

[a] Because EPA estimated non-use benefits only qualitatively, the monetary value of benefits includes use values only.

[b] No I&E reductions are expected in the South Atlantic region because all potentially regulated facilities in this region already meet the national categorical requirements in the baseline and therefore would not be required to install technologies to comply with this option.

[c] The present value (PV) is estimated by discounting individual annual values to 2007, using the stated discount rate.

[d] Annualized benefits represent the value of all benefits generated over the time frame of the analysis, discounted to 2007, and then annualized over a 30-year period.

Source: U.S. EPA Analysis, 2004.

E2A-3 TOTAL ANNUALIZED MONETARY VALUE OF BENEFITS

Tables E2A-7 and E2A-8 present EPA's estimates of the value of national and regional reductions in I&E under the other options analyzed for the proposed rule, using 3% and 7% discount rates. The tables shows for all other options, that benefits to recreational anglers account for the majority of use benefits. National use benefits are largest in the Gulf of Mexico region under all five options. More detailed discussions of regional benefits under each option are provided in Sections B through G of the RBA.

Table E2A-7: Summary of Monetized Benefits for Existing Phase III Facilities[a] (thousands; 2003$; discounted at 3%)

Region	Annualized Use Benefits of I&E Reductions						
	Annualized Commercial Fishing	Recreational Fishing			Total Use Value[b]		
		Low	Mean	High	Low	Mean	High
Option 3							
California	$0 - $5	$10	$24	$57	$15	$29	$62
North Atlantic	$0 - $3	$29	$63	$138	$32	$66	$141
Mid-Atlantic	$0 - $25	$236	$499	$1,061	$261	$525	$1,086
South Atlantic[c]	$0	$0	$0	$0	$0	$0	$0
Gulf of Mexico	$0 - $80	$259	$580	$1,305	$339	$660	$1,385
Great Lakes	$0 - $23	$177	$355	$697	$200	$378	$720
Inland[d]	n/a	$176	$334	$630	$176	$334	$630
National Total	**$0 - $137**	**$888**	**$1,856**	**$3,888**	**$1,024**	**$1,993**	**$4,025**
Option 4							
California	$0 - $10	$20	$47	$110	$30	$57	$120
North Atlantic	$0 - $3	$29	$63	$138	$32	$66	$141
Mid-Atlantic	$0 - $25	$239	$506	$1,074	$265	$531	$1,100
South Atlantic[c]	$0	$0	$0	$0	$0	$0	$0
Gulf of Mexico	$0 - $83	$263	$589	$1,325	$346	$672	$1,408
Great Lakes	$0 - $23	$178	$359	$704	$202	$382	$728
Inland[d]	n/a	$162	$306	$577	$162	$306	$577
National Total	**$0 - $144**	**$892**	**$1,870**	**$3,929**	**$1,036**	**$2,014**	**$4,073**
Option 2							
California	$0 - $10	$20	$47	$110	$30	$57	$120
North Atlantic	$0 - $3	$29	$63	$138	$32	$66	$141
Mid-Atlantic	$0 - $25	$239	$506	$1,074	$265	$531	$1,100
South Atlantic[c]	$0	$0	$0	$0	$0	$0	$0
Gulf of Mexico	$0 - $83	$263	$589	$1,325	$346	$672	$1,408
Great Lakes	$0 - $23	$178	$359	$704	$202	$382	$728
Inland[d]	n/a	$162	$306	$577	$162	$306	$577
National Total	**$0 - $144**	**$892**	**$1,870**	**$3,929**	**$1,036**	**$2,014**	**$4,073**

Table E2A-7: Summary of Monetized Benefits for Existing Phase III Facilities[a] (thousands; 2003$; discounted at 3%)

Region	Annualized Use Benefits of I&E Reductions						
	Annualized Commercial Fishing	Recreational Fishing			Total Use Value[b]		
		Low	Mean	High	Low	Mean	High
Option 1							
California	$0 - $10	$20	$47	$110	$30	$57	$120
North Atlantic	$0 - $3	$29	$63	$138	$32	$66	$141
Mid-Atlantic	$0 - $25	$239	$506	$1,074	$265	$531	$1,100
South Atlantic[c]	$0	$0	$0	$0	$0	$0	$0
Gulf of Mexico	$0 - $83	$263	$589	$1,325	$346	$672	$1,408
Great Lakes	$0 - $23	$178	$359	$704	$202	$382	$728
Inland[d]	n/a	$182	$344	$649	$182	$344	$649
National Total	**$0 - $144**	**$912**	**$1,908**	**$4,001**	**$1,056**	**$2,052**	**$4,146**
Option 6							
California	$0 - $10	$20	$47	$110	$30	$57	$120
North Atlantic	$0 - $3	$29	$63	$138	$32	$66	$141
Mid-Atlantic	$0 - $26	$241	$510	$1,083	$267	$535	$1,109
South Atlantic[c]	$0	$0	$0	$0	$0	$0	$0
Gulf of Mexico	$0 - $83	$263	$589	$1,325	$346	$672	$1,408
Great Lakes	$0 - $25	$192	$386	$758	$217	$411	$783
Inland[d]	n/a	$189	$357	$673	$189	$357	$673
National Total	**$0 - $146**	**$934**	**$1,952**	**$4,087**	**$1,080**	**$2,098**	**$4,233**

[a] All benefits presented in this table are annualized. These annualized benefits represent the value of all benefits generated over the time frame of the analysis, discounted to 2007, and then annualized over a 30-year period.

[b] The total monetizable value of I&E reductions includes use benefits only. EPA evaluated non-use benefits only qualitatively. A range of recreational fishing benefits is provided, based on the Krinsky and Robb technique to estimated the 95th and 5th percentile limits on the marginal value per fish predicted by EPA's meta-analysis (see chapter A5 of the RBA). Commercial fishing benefits are computed based on a range from 0% to 40% of the change in gross revenue (see Chapter A4 of the RBA). To calculate the total use value columns (low, mean, and high), the high end value for commercial fishing benefits is added to the low, mean, and high values for recreational fishing benefits, respectively.

[c] No I&E reductions are expected in the South Atlantic region because all potentially regulated facilities in this region already meet the national categorical requirements in the baseline and therefore would not be required to install technologies to comply with these options.

[d] No significant commercial fishing takes place in the Inland region, and thus this region is excluded from the commercial fishing benefits analysis.

Source: U.S. EPA Analysis, 2004.

Table E2A-8: Summary of Monetized Benefits for Existing Phase III Facilities[a] (thousands; 2003$, discounted at 7%)

Region	Annualized Use Benefits of I&E Reductions						
	Annualized Commercial Fishing	Recreational Fishing			Total Use Value[b]		
		Low	Mean	High	Low	Mean	High
Option 3							
California	$0 - $4	$8	$19	$45	$12	$23	$49
North Atlantic	$0 - $2	$22	$49	$107	$25	$51	$109
Mid-Atlantic	$0 - $19	$181	$383	$814	$201	$403	$834
South Atlantic[c]	$0	$0	$0	$0	$0	$0	$0
Gulf of Mexico	$0 - $64	$206	$462	$1,038	$270	$526	$1,102
Great Lakes	$0 - $18	$138	$277	$543	$156	$295	$561
Inland[d]	n/a	$144	$273	$515	$144	$273	$515
National Total	**$0 - $107**	**$700**	**$1,463**	**$3,063**	**$807**	**$1,570**	**$3,170**
Option 4							
California	$0 - $8	$16	$37	$86	$24	$44	$94
North Atlantic	$0 - $2	$22	$49	$107	$25	$51	$109
Mid-Atlantic	$0 - $19	$184	$388	$825	$203	$408	$844
South Atlantic[c]	$0	$0	$0	$0	$0	$0	$0
Gulf of Mexico	$0 - $66	$209	$469	$1,055	$275	$535	$1,120
Great Lakes	$0 - $18	$139	$280	$549	$157	$298	$567
Inland[d]	n/a	$133	$251	$473	$133	$251	$473
National Total	**$0 - $114**	**$703**	**$1,473**	**$3,095**	**$816**	**$1,587**	**$3,208**
Option 2							
California	$0 - $8	$16	$37	$86	$24	$44	$94
North Atlantic	$0 - $2	$22	$49	$107	$25	$51	$109
Mid-Atlantic	$0 - $19	$184	$388	$825	$203	$408	$844
South Atlantic[c]	$0	$0	$0	$0	$0	$0	$0
Gulf of Mexico	$0 - $66	$209	$469	$1,055	$275	$535	$1,120
Great Lakes	$0 - $18	$139	$280	$549	$157	$298	$567
Inland[d]	n/a	$133	$251	$473	$133	$251	$473
National Total	**$0 - $114**	**$703**	**$1,473**	**$3,095**	**$816**	**$1,587**	**$3,208**
Option 1							
California	$0 - $8	$16	$37	$86	$24	$44	$94
North Atlantic	$0 - $2	$22	$49	$107	$25	$51	$109
Mid-Atlantic	$0 - $19	$184	$388	$825	$203	$408	$844
South Atlantic[c]	$0	$0	$0	$0	$0	$0	$0
Gulf of Mexico	$0 - $66	$209	$469	$1,055	$275	$535	$1,120
Great Lakes	$0 - $18	$139	$280	$549	$157	$298	$567
Inland[d]	n/a	$149	$281	$531	$149	$281	$531

Table E2A-8: Summary of Monetized Benefits for Existing Phase III Facilities[a] (thousands; 2003$, discounted at 7%)

Region	Annualized Use Benefits of I&E Reductions						
	Annualized Commercial Fishing	Recreational Fishing			Total Use Value[b]		
		Low	Mean	High	Low	Mean	High
National Total	**$0 - $114**	**$719**	**$1,504**	**$3,152**	**$832**	**$1,617**	**$3,266**
Option 6							
California	$0 - $8	$16	$37	$86	$24	$44	$94
North Atlantic	$0 - $2	$22	$49	$107	$25	$51	$109
Mid-Atlantic	$0 - $20	$185	$391	$831	$205	$411	$850
South Atlantic[c]	$0	$0	$0	$0	$0	$0	$0
Gulf of Mexico	$0 - $66	$209	$469	$1,055	$275	$535	$1,120
Great Lakes	$0 - $20	$150	$302	$592	$170	$322	$612
Inland[d]	n/a	$154	$291	$549	$154	$291	$549
National Total	**$0 - $115**	**$736**	**$1,539**	**$3,220**	**$852**	**$1,654**	**$3,335**

[a] All benefits presented in this table are annualized. These annualized benefits represent the value of all benefits generated over the time frame of the analysis, discounted to 2007, and then annualized over a 30-year period.

[b] The total monetizable value of I&E reductions includes use benefits only. EPA evaluated non-use benefits only qualitatively. A range of recreational fishing benefits is provided, based on the Krinsky and Robb technique to estimated the 95th and 5th percentile limits on the marginal value per fish predicted by EPA's meta-analysis (see chapter A5 of the RBA). Commercial fishing benefits are computed based on a range from 0% to 40% of the change in gross revenue (see Chapter A4 of the RBA). To calculate the total use value columns (low, mean, and high), the high end value for commercial fishing benefits is added to the low, mean, and high values for recreational fishing benefits, respectively.

[c] No I&E reductions are expected in the South Atlantic region because all potentially regulated facilities in this region already meet the national categorical requirements in the baseline and therefore would not be required to install technologies to comply with these options.

[d] No significant commercial fishing takes place in the Inland region, and thus this region is excluded from the commercial fishing benefits analysis.

Source: U.S. EPA Analysis, 2004.

Chapter E3: Comparison of Benefits and Social Costs

INTRODUCTION

This chapter compares total monetized benefits to total social costs for the options analyzed for the Proposed Section 316(b) Rule for Phase III Facilities. Benefits and costs are compared on two bases: (1) for each of the options analyzed and (2) incrementally across options. For more information on the analysis of social costs and benefits, see *Chapter E1: Summary of Social Costs* and *Chapter E2: Summary of Benefits*.

CHAPTER CONTENTS

EPA considered and analyzed three proposed options and five other options for Phase III existing facilities (Manufacturers and Generators) in developing the proposed rule. New offshore oil and gas extraction facilities were excluded from the comparison of benefits and costs because EPA was unable to estimate benefits for this industry segment. This chapter presents results for the three proposed options for existing facilities: the "50 MGD for All Waterbodies" option ("50 MGD All"), the "200 MGD for All Waterbodies" option ("200 MGD All"), and the "100 MGD for Certain Waterbodies" option ("100 MGD CWB"). Summary results for five other options evaluated in regulation development are presented in the appendix to this chapter.

Table E3-1 shows compliance action assumptions for the three proposed options based on the performance standard each facility would need to meet (depending on each facility's waterbody type, design intake flow, capacity utilization, and annual intake flow as a percent of source waterbody mean annual flow) and its baseline technologies in-place.

Table E3-1: Number of Existing Phase III Facilities by Compliance Action[a]

Facility Compliance Action	50 MGD All	200 MGD All	100 MGD CWB
Total Facilities Potentially Subject to Regulation (excluding baseline closures)	**603**	**603**	**603**
Facilities Subject to Best Professional Judgment	468	579	584
Facilities Subject to National Categorical Requirements	136	25	19
No compliance action[b]	*32*	*2*	*1*
Impingement controls only	*37*	*3*	*0*
Impingement and entrainment controls	*66*	*19*	*18*

[a] Alternative less stringent requirements based on site-specific assessments of costs, or costs and benefits are allowed. Estimation of compliance responses is uncertain because the number of facilities requesting alternative less stringent requirements based on these site-specific assessments is unknown.
[b] These facilities meet compliance requirements in the baseline and thus would require no action to comply with the regulation.

Source: U.S. EPA Analysis, 2004.

E3-1 COMPARISON OF BENEFITS AND SOCIAL COSTS BY OPTION

The preceding chapters, *Chapter E1: Summary of Social Costs* and *Chapter E2: Summary of Benefits*, present estimates of total social cost and benefit for the three proposed and five other options evaluated in developing the 316(b) Phase III regulation. Based on these values of estimated benefits and social costs, EPA calculated the net monetized benefit to society of each option.

As documented in *Chapter E2: Summary of Benefits*, the monetized benefit values developed by EPA for the 316(b) Phase III regulation, and included in the net benefits calculation presented in this chapter, include only *use benefit* values for commercial and recreational fishing. EPA was unable to estimate, at this time, a monetized value of non-use benefits from reduced impingement and entrainment (I&E). As a result, the monetized benefit value that is compared with the estimated value of total social cost in this benefit-cost comparison, is narrow in conceptual scope and omits a benefit category with potentially large monetary value. Specifically, the Agency was unable to monetize benefits for 96.7% of the age-one equivalent losses of all commercial, recreational, and forage species considered for the options for Phase III existing facilities. As a result, the benefits estimates used in this analysis represent the benefits associated with only about 3.3% of the total avoided loss in age-one equivalents. Accordingly, the net benefit values presented in this chapter are based on comparison of a substantially complete estimate of costs to society with a substantially incomplete estimate of benefits.

Table E3-2, below, presents EPA's estimates of use benefits and social costs for the three proposed options for existing facilities, at 3% and 7% discount rates. At a 3% discount rate, EPA estimates that social costs exceed use benefits by $45.4 million under the 50 MGD All option, $21.5 million under the 200 MGD All option, and $16.2 million under the 100 MGD CWB option. At a 7% discount rate, social costs exceed use benefits by $48.6 million under the 50 MGD All option, $23.1 million under the 200 MGD All option, and $17.2 million under the 100 MGD CWB option. These values are all in dollars as of mid-year 2003 and are based on the discounting of costs and benefits to beginning of year 2007, the assumed date when the proposed rule would take effect.

Table E3-2: Total Benefits, Social Costs, and Net Benefits for Existing Phase III Facilities by Option (millions; 2003$)

Option	Total Monetized Use Benefits[a]			Total Social Costs	Net Benefits Based on Use Benefits Only[b]		
	Low	Mean	High		Low	Mean	High
3% discount rate							
50 MGD All	$1.0	$1.9	$3.8	$47.3	($46.4)	($45.4)	($43.5)
200 MGD All	$0.6	$1.3	$2.5	$22.8	($22.1)	($21.5)	($20.2)
100 MGD CWB	$0.7	$1.4	$2.9	$17.6	($16.9)	($16.2)	($14.7)
7% discount rate							
50 MGD All	$0.8	$1.5	$3.0	$50.1	($49.3)	($48.6)	($47.1)
200 MGD All	$0.5	$1.0	$2.0	$24.1	($23.6)	($23.1)	($22.1)
100 MGD CWB	$0.6	$1.1	$2.3	$18.3	($17.7)	($17.2)	($16.0)

[a] The total monetizable value of I&E reductions includes use benefits only. EPA evaluated non-use benefits only qualitatively. The range (low, mean, and high) of annualized use values is computed by adding the high end value for commercial fishing benefits (based on assumed producer surplus of 40% of gross revenue) to the low, mean, and high values from recreational fishing benefits, respectively (see Chapter A4 of the RBA).

[b] Net benefits are computed by subtracting total annualized costs from total annual use benefits. The net benefits presented here are based on the comparison of a substantially complete measure of social costs with an incomplete measure of benefits and should be interpreted with caution.

Source: U.S. EPA Analysis, 2004.

This comparison of fairly complete costs and incomplete benefits provides an incomplete assessment of net benefits to society. The proposed options are expected to provide benefits that were not accounted for in the benefits analysis. These benefits include reduced I&E losses of fish, shellfish, and other aquatic organisms, which, in turn, 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 A6 of the *Regional Benefits Assessment for the Proposed Section 316(b) Rule for Phase III Facilities* (RBA) for a detailed description of the ecological benefits from reduced I&E (U.S. EPA, 2004). Taking into account these additional unquantified benefits of improved fisheries and aquatic ecosystem functioning, the Agency believes that the total benefits to society of the proposed rule for Phase III existing facilities could potentially exceed total social costs.

Tables E3-3 and E3-4 present total net benefits for existing Phase III facilities by option and region, discounted at 3% and 7%, respectively. As reported in Tables E3-3 and E3-4, EPA estimates that costs are largest relative to benefits in the Inland region for the 50 MGD All and 200 MGD All options, and in the Gulf of Mexico region for the 100 MGD CWB option. Conversely, costs outweigh benefits by the least amount in the California region for the 50 MGD All option, in the North Atlantic region for the 200 MGD All option, and in the Mid-Atlantic region for the 100 MGD CWB option.

Table E3-3: Total Net Benefits for Existing Phase III Facilities by Option and Region (millions; 2003$, discounted at 3%)

Option	Net Benefits Based on Use Benefits Only[a]							
	California	North Atlantic	Mid-Atlantic	South Atlantic[b]	Gulf of Mexico	Great Lakes	Inland	National Total
Low								
50 MGD All	($0.8)	($4.5)	($2.3)	$0.0	($8.7)	($9.9)	($19.5)	($46.4)
200 MGD All	$0.0	($0.5)	($1.7)	$0.0	($3.6)	($3.9)	($12.2)	($22.1)
100 MGD CWB	$0.0	($2.0)	($1.7)	$0.0	($8.7)	($4.3)	$0.0	($16.9)
Mean								
50 MGD All	($0.8)	($4.5)	($2.0)	$0.0	($8.4)	($9.7)	($19.4)	($45.4)
200 MGD All	$0.0	($0.5)	($1.5)	$0.0	($3.5)	($3.8)	($12.1)	($21.5)
100 MGD CWB	$0.0	($1.9)	($1.5)	$0.0	($8.4)	($4.2)	$0.0	($16.2)
High								
50 MGD All	($0.8)	($4.4)	($1.5)	$0.0	($7.7)	($9.4)	($19.1)	($43.5)
200 MGD All	$0.0	($0.5)	($1.0)	$0.0	($3.1)	($3.6)	($11.9)	($20.2)
100 MGD CWB	$0.0	($1.9)	($1.0)	$0.0	($7.7)	($4.0)	$0.0	($14.7)

[a] Net benefits are computed by subtracting total annualized costs from total annual use benefits. The net benefits presented here are based on the comparison of a substantially complete measure of social costs with an incomplete measure of benefits and should be interpreted with caution.

[b] No benefits or costs are expected in the South Atlantic region because all potentially regulated facilities in this region withdraw less than 50 MGD and therefore would not be required to install technologies to comply with the proposed options.

Source: U.S. EPA Analysis, 2004.

Table E3-4: Total Net Benefits for Existing Phase III Facilities by Option and Region (millions; 2003$, discounted at 7%)

Option	Net Benefits Based on Use Benefits Only[a]							
	California	North Atlantic	Mid-Atlantic	South Atlantic[b]	Gulf of Mexico	Great Lakes	Inland	National Total
Low								
50 MGD All	($1.0)	($5.0)	($2.2)	$0.0	($9.9)	($10.1)	($20.5)	($49.3)
200 MGD All	$0.0	($0.5)	($1.6)	$0.0	($4.2)	($3.6)	($13.6)	($23.6)
100 MGD CWB	$0.0	($2.0)	($1.6)	$0.0	($9.9)	($4.0)	$0.0	($17.7)
Mean								
50 MGD All	($0.9)	($5.0)	($2.0)	$0.0	($9.7)	($9.9)	($20.4)	($48.6)
200 MGD All	$0.0	($0.5)	($1.4)	$0.0	($4.1)	($3.5)	($13.5)	($23.1)
100 MGD CWB	$0.0	($2.0)	($1.4)	$0.0	($9.7)	($3.9)	$0.0	($17.2)
High								
50 MGD All	($0.9)	($4.9)	($1.6)	$0.0	($9.1)	($9.7)	($20.2)	($47.1)
200 MGD All	$0.0	($0.4)	($1.1)	$0.0	($3.8)	($3.3)	($13.4)	($22.1)
100 MGD CWB	$0.0	($1.9)	($1.1)	$0.0	($9.1)	($3.7)	$0.0	($16.0)

[a] Net benefits are computed by subtracting total annualized costs from total annual use benefits. The net benefits presented here are based on the comparison of a substantially complete measure of social costs with an incomplete measure of benefits and should be interpreted with caution.

[b] No benefits or costs are expected in the South Atlantic region because all potentially regulated facilities in this region withdraw less than 50 MGD and therefore would not be required to install technologies to comply with the proposed options.

Source: U.S. EPA Analysis, 2004.

Table E3-5, on the following page, provides additional detail on the net benefits calculation. Table E3-5 compiles, for the three proposed options, the time profiles of benefits and costs as presented in the preceding chapters. The table also reports the calculated present and annualized values of benefits and costs at 3% and 7% discount rates.

Table E3-5: Time Profile of Benefits and Social Costs for Existing Phase III Facilities (millions; 2003$)

Year	50 MGD All		200 MGD All		100 MGD CWB	
	Monetized Benefits	Total Cost (excl. O&G)	Monetized Benefits	Total Cost (excl. O&G)	Monetized Benefits	Total Cost (excl. O&G)
2007	$0.00	$3.3	$0.00	$0.2	$0.00	$0.6
2008	$0.00	$10.2	$0.00	$1.4	$0.00	$3.8
2009	$0.00	$15.4	$0.00	$2.1	$0.00	$3.9
2010	$0.01	$172.6	$0.00	$129.1	$0.00	$9.0
2011	$0.05	$180.5	$0.03	$83.8	$0.01	$139.7
2012	$0.22	$74.4	$0.11	$12.3	$0.09	$11.5
2013	$0.63	$110.8	$0.34	$45.8	$0.27	$35.3
2014	$1.28	$22.2	$0.70	$7.5	$0.85	$5.4
2015	$1.83	$22.7	$1.16	$8.5	$1.32	$8.3
2016	$2.12	$18.6	$1.40	$7.5	$1.57	$5.4
2017	$2.22	$18.6	$1.47	$9.0	$1.66	$6.6
2018	$2.27	$15.3	$1.52	$7.5	$1.70	$5.3
2019	$2.29	$19.0	$1.53	$7.3	$1.72	$5.2
2020	$2.29	$44.5	$1.53	$12.7	$1.72	$8.3
2021	$2.29	$81.7	$1.53	$40.0	$1.72	$41.4
2022	$2.29	$29.2	$1.53	$14.6	$1.72	$12.2
2023	$2.29	$58.2	$1.53	$45.8	$1.72	$35.4
2024	$2.29	$22.1	$1.53	$7.4	$1.72	$5.4
2025	$2.29	$22.7	$1.53	$8.5	$1.72	$8.3
2026	$2.29	$18.6	$1.53	$7.5	$1.72	$5.4
2027	$2.29	$18.6	$1.53	$9.0	$1.72	$6.6
2028	$2.29	$15.3	$1.53	$7.5	$1.72	$5.3
2029	$2.29	$19.0	$1.53	$7.3	$1.72	$5.2
2030	$2.29	$44.5	$1.53	$12.7	$1.72	$8.3
2031	$2.29	$81.7	$1.53	$40.0	$1.72	$41.4
2032	$2.29	$29.2	$1.53	$14.6	$1.72	$12.2
2033	$2.29	$58.2	$1.53	$45.8	$1.72	$35.4
2034	$2.29	$22.1	$1.53	$7.4	$1.72	$5.4
2035	$2.29	$22.7	$1.53	$8.5	$1.72	$8.3
2036	$2.29	$18.6	$1.53	$7.5	$1.72	$5.4
2037	$2.29	$18.6	$1.53	$9.0	$1.72	$6.6
2038	$2.29	$15.3	$1.53	$7.5	$1.72	$5.3
2039	$2.29	$14.4	$1.53	$7.1	$1.72	$4.8
2040	$2.28	$12.1	$1.53	$6.8	$1.72	$4.7
2041	$2.23	$6.3	$1.50	$3.9	$1.71	$2.2
2042	$2.06	$4.1	$1.42	$3.1	$1.62	$1.3
2043	$1.66	$0.5	$1.19	$0.4	$1.45	$0.4
2044	$1.01	$0.0	$0.83	$0.0	$0.87	$0.0
2045	$0.46	$0.0	$0.37	$0.0	$0.40	$0.0
2046	$0.17	$0.0	$0.13	$0.0	$0.15	$0.0
2047	$0.06	$0.0	$0.06	$0.0	$0.05	$0.0
2048	$0.01	$0.0	$0.01	$0.0	$0.01	$0.0
PV 3%	**$37.18**	**$955.8**	**$24.70**	**$459.7**	**$27.65**	**$355.9**
Annualized 3%	**$1.90**	**$47.3**	**$1.26**	**$22.8**	**$1.41**	**$17.6**
PV 7%	**$18.56**	**$665.0**	**$12.21**	**$320.3**	**$13.63**	**$242.5**
Annualized 7%	**$1.50**	**$50.1**	**$0.98**	**$24.1**	**$1.10**	**$18.3**

Source: U.S. EPA Analysis, 2004.

E3-2 INCREMENTAL ANALYSIS OF BENEFITS AND SOCIAL COSTS

In addition to comparing benefits and costs for each proposed option, as presented in the preceding section, EPA also analyzed the benefits and costs of the three options on an incremental basis. The comparison in the preceding section addresses the simple quantitative relationship between estimated benefits and costs for each option by itself: for a given option, which is greater – benefits or costs – and what is the amount of difference? In contrast, incremental analysis looks at the differential relationship of benefits and costs across options and poses a different question: as increasingly more costly options are considered, by what amount do benefits, costs, and net benefits change from option to option? Incremental benefit-cost analysis provides insight into the net gain to society from imposing increasingly more costly requirements and may aid regulatory decision-makers in choosing among a set of regulatory proposals that otherwise have a similar quantitative relationship between benefits and costs based on a one-option-at-a-time comparison.

The Agency conducted the incremental benefit-cost analysis by calculating, for each option, the change in net benefits, from option to option, in moving from the least costly option to successively more costly options. As described previously, the three proposed options – the 50 MGD All, 200 MGD All, and 100 MGD CWB options – differ in terms of design intake flow (DIF) applicability threshold and affected waterbodies. Thus the difference in benefits and costs across the options derives from the number of facilities each option is expected to cover and what types of waterbodies are affected. As reported in Table E3-6, at a 3% discount rate, the incremental change in net benefits in moving from the 100 MGD CWB option to the 200 MGD All option is -$5.3 million, and from the 200 MGD All option to the 50 MGD All option, is -$23.9 million. Thus, for both incremental steps, calculated net benefits become increasingly more negative but the step from the 200 MGD All option to the 50 MGD All option is more costly to society, on a net benefit basis, than the step from the 100 MGD CWB option to the 200 MGD All option. The same pattern of change occurs for the calculations under a 7% discount rate: the incremental change in net benefits in moving from the 100 MGD CWB option to the 200 MGD All option is -$6.0 million, and from the 200 MGD All option to the 50 MGD All option, is -$25.4 million.

Table E3-6: Incremental Benefit-Cost Analysis for Existing Phase III Facilities (millions; 2003$)

Option[a]	Net Benefits Based on Use Benefits Only[b]			Incremental Net Benefits[c]		
	Low	Mean	High	Low	Mean	High
3% discount rate						
100 MGD CWB	($16.9)	($16.2)	($14.7)	n/a	n/a	n/a
200 MGD All	($22.1)	($21.5)	($20.2)	($5.2)	($5.3)	($5.5)
50 MGD All	($46.4)	($45.4)	($43.5)	($24.2)	($23.9)	($23.3)
7% discount rate						
100 MGD CWB	($17.7)	($17.2)	($16.0)	n/a	n/a	n/a
200 MGD All	($23.6)	($23.1)	($22.1)	($5.9)	($6.0)	($6.1)
50 MGD All	($49.3)	($48.6)	($47.1)	($25.7)	($25.4)	($24.9)

[a] Options are presented in order of increasing applicability, based on the number of facilities regulated.
[b] Net benefits are computed by subtracting total annualized costs from total annual use benefits. The net benefits presented here are based on the comparison of a substantially complete measure of social costs with an incomplete measure of benefits and should be interpreted with caution.
[c] Incremental net benefits are equal to the difference between net benefits of a given option and the net benefits of the previous less stringent option.

Source: U.S. EPA Analysis, 2004.

E3-3 BREAK-EVEN ANALYSIS OF POTENTIAL NON-USE BENEFITS

As described in Section E3-1, above, EPA's monetized estimates of benefits for the 316(b) Phase III regulation consider only the *use benefit* values for commercial and recreational fishing, and exclude *non-use benefits*. Estimating non-use benefit values is a very challenging and uncertain exercise, particularly when primary research using stated preference methods is not a feasible option (as is the case for the proposed rulemaking). In Chapter A3 of the RBA, EPA described alternative approaches for developing non-use benefit estimates based on benefits transfer and associated methods. Because of the uncertainty in estimating the non-use benefits of the options evaluated for the proposed rule, the Agency assessed non-use benefits only qualitatively (see Chapter A6 of RBA for a qualitative assessment of non-use benefits). As a result, the comparison of costs and benefits presented in Sections E3-1 and E3-2 involves a substantially more complete accounting of costs than of benefits. On the basis of this limited, incomplete accounting of benefits and costs, EPA found that costs exceed use benefits for each of the three proposed options.

Although EPA did not specifically estimate the non-use benefits of the 316(b) Phase III regulation, it is possible to calculate the amount of non-use benefits that would be needed for the regulation's benefits to equal the estimated total costs (the "break-even" non-use benefits value). Regulatory decision-makers may then judge the reasonableness of these required values in assessing whether the regulation is likely, overall, to achieve total benefits to society that exceed costs.

To perform this break-even analysis, EPA subtracted the estimated commercial and recreational use benefits from the estimated annual costs. EPA then used this required residual to calculate the non-use benefit value, in terms of annual willingness-to-pay (WTP), needed for total benefits to equal total costs. This calculation was done in two different ways: (1) on a per household basis and (2) on a per age-1 equivalent basis. EPA performed this analysis using the regional studies framework as described in the RBA. This approach assumes that all of the facilities in the sample weight of a given sample facility are in the same benefits analysis region as the sample facility.

For the WTP per household analysis, this approach also assumes that the size and other characteristics of potential use and non-use benefit populations, which are assessed for the sample facility, may be extended to the weight of the sample facility. Although this assumption embeds considerable uncertainty, it permits the estimation of a non-use benefit population for each facility, which may then be used to calculate the WTP value by household that equates total benefits and total costs, on a sample-weighted basis, for each option. For this analysis, EPA assumed that only anglers fishing in the region and households within a 25-mile radius of the facility hold non-use values for the affected resources (BLS, 2000).[1]

At the national level, EPA estimated the following (see Table E3-7 below):

- **WTP per household.** Under the 50 MGD All option, non-use benefit values per household would have to be $1.99 (3% discount rate) and $2.13 (7% discount rate) for total annual benefits to equal total annualized costs. Under the 200 MGD All option, which applies to the next smaller set of facilities, these values decrease to $1.87 (3% discount rate) and $2.01 (7% discount rate). Under the 100 MGD CWB option, which applies to the smallest set of facilities of the three proposed options, these values decrease, to $1.43 (3% discount rate) and $1.52 (7% discount rate).

- **WTP per age-1 equivalent.** Under the 50 MGD All option, non-use benefit values per age-1 equivalent would have to be $0.92 (3% discount rate) and $0.98 (7% discount rate) for total annual benefits to equal total annualized costs. Under the 200 MGD All option, which applies to the next smaller set of facilities, these values decrease to $0.63 (3% discount rate) and $0.68 (7% discount rate). Under the 100 MGD CWB option, which applies to the smallest set of facilities of the three proposed options, these values decrease, to $0.54 (3% discount rate) and $0.58 (7% discount rate).

[1] See chapter E2 for details on the estimation of age-1 equivalents.

Table E3-7: Estimated Value of Non-Use Benefits Required for Total Benefits to Equal Total Social Costs for Existing Phase III Facilities - Break-Even Analysis (2003$)

Option	Total Social Costs (millions)	Mean Value of Use Benefits (millions)	Non-Use Benefits Necessary to Break Even[a] (millions)	Number of Households	Break-Even WTP per Household ($)	Reduction of I&E Losses (Age-1 Equivalents)	Break-Even Value per Age-1 Equivalent[b] ($)
3% Discount Rate							
50 MGD All	$47.3	$1.9	$45.4	22,784,450	$1.99	49,493,000	$0.92
200 MGD All	$22.8	$1.3	$21.5	11,524,368	$1.87	34,038,000	$0.63
100 MGD CWB	$17.6	$1.4	$16.2	11,328,241	$1.43	29,774,000	$0.54
7% Discount Rate							
50 MGD All	$50.1	$1.5	$48.6	22,784,450	$2.13	49,493,000	$0.98
200 MGD All	$24.1	$1.0	$23.1	11,524,368	$2.01	34,038,000	$0.68
100 MGD CWB	$18.3	$1.1	$17.2	11,328,241	$1.52	29,774,000	$0.58

[a] 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.
[b] The non-use value per age-1 equivalent reported in the table includes the value placed on the fish's contribution to non-use ecological services (e.g., population, health, sustainability, and overall ecosystem health).

Source: U.S. EPA Analysis, 2004.

EPA also calculated the annual WTP needed on a per household basis and a per age-1 equivalent basis at the regional level (see Tables E3-8 and E3-9 below). EPA estimated the following:

- **WTP per household.** The Gulf of Mexico region has the highest estimated annual break-even WTP values per household with $6.38, $13.83, and $6.38 (3% discount rate) and $7.34, $16.31, and $7.34 (7% discount rate) under the 50 MGD All, the 200 MGD All, and the 100 MGD CWB options, respectively. The Mid-Atlantic region has the lowest estimated annual break-even WTP values per household with $0.35, $0.27, and $0.27 (3% discount rate) and $0.35, $0.25, and $0.25 (7% discount rate) under the 50 MGD All, the 200 MGD All, and the 100 MGD CWB options, respectively.

- **WTP per age-1 equivalent.** The North Atlantic region has the highest estimated annual break-even WTP value per age-1 equivalent with $4.84, $2.51, and $2.56 (3% discount rate) and $5.37, $2.28, and $2.62 (7% discount rate) under the 50 MGD All, the 200 MGD All, and the 100 MGD CWB options, respectively. The Mid-Atlantic region has the lowest estimated annual break-even WTP values per age-1 equivalent with $0.15, $0.13, and $0.13 (3% discount rate) and $0.15, $0.12, and $0.12 (7% discount rate) under the 50 MGD All, the 200 MGD All, and the 100 MGD CWB options, respectively.

Table E3-8: Estimated Value of Non-Use Benefits Required for Total Benefits to Equal Total Social Costs for Existing Phase III Facilities - Break-Even Analysis by Regions (2003$, discounted at 3%)

Option	Total Social Costs (millions)	Mean Value of Use Benefits (millions)	Non-Use Benefits Necessary to Break Even[a] (millions)	Number of Households	Break-Even WTP per Household ($)	Reduction of I&E Losses (Age-1 Equivalents)	Break-Even Value per Age-1 Equivalent[b] ($)
50 MGD All							
California	$0.8	$0.0[d]	$0.8	1,166,416	$0.70	383,000	$2.14
North Atlantic	$4.6	$0.1	$4.5	2,129,180	$2.11	930,000	$4.84
Mid-Atlantic	$2.6	$0.5	$2.0	5,887,031	$0.35	13,400,000	$0.15
South Atlantic[c]	$0.0	$0.0	$0.0	0	$0.00	0	$0.00
Gulf of Mexico	$9.1	$0.6	$8.4	1,322,480	$6.38	8,380,000	$1.01
Great Lakes	$10.1	$0.3	$9.7	4,064,660	$2.40	11,600,000	$0.84
Inland	$19.7	$0.3	$19.4	8,214,682	$2.36	14,800,000	$1.31
National Total	**$47.3**	**$1.9**	**$45.4**	**22,784,450**	**$1.99**	**49,493,000**	**$0.92**
200 MGD All							
California	$0.0	$0.0	$0.0	0	$0.00	0	$0.00
North Atlantic	$0.5	$0.0[d]	$0.5	1,699,855	$0.29	198,000	$2.51
Mid-Atlantic	$2.0	$0.5	$1.5	5,603,551	$0.27	11,900,000	$0.13
South Atlantic[c]	$0.0	$0.0	$0.0	0	$0.00	0	$0.00
Gulf of Mexico	$3.8	$0.3	$3.5	251,666	$13.83	4,580,000	$0.76
Great Lakes	$4.1	$0.2	$3.8	2,388,297	$1.60	7,710,000	$0.50
Inland	$12.3	$0.2	$12.1	1,580,998	$7.65	9,650,000	$1.25
National Total	**$22.8**	**$1.3**	**$21.5**	**11,524,368**	**$1.87**	**34,038,000**	**$0.63**
100 MGD CWB							
California	$0.0	$0.0	$0.0	0	$0.00	0	$0.00
North Atlantic	$2.0	$0.1	$1.9	1,989,096	$0.97	754,000	$2.56
Mid-Atlantic	$2.0	$0.5	$1.5	5,603,551	$0.27	11,900,000	$0.13
South Atlantic[c]	$0.0	$0.0	$0.0	0	$0.00	0	$0.00
Gulf of Mexico	$9.1	$0.6	$8.4	1,322,480	$6.38	8,380,000	$1.01
Great Lakes	$4.5	$0.3	$4.2	2,413,114	$1.74	8,740,000	$0.48
Inland	$0.0	$0.0	$0.0	0	$0.00	0	$0.00
National Total	**$17.6**	**$1.4**	**$16.2**	**11,328,241**	**$1.43**	**29,774,000**	**$0.54**

[a] 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.

[b] The non-use value per age-1 equivalent reported in the table includes the value placed on the fish's contribution to non-use ecological services (e.g., population, health, sustainability, and overall ecosystem health).

[c] No benefits or costs are expected in the South Atlantic region because all potentially regulated facilities in this region withdraw less than 50 MGD and therefore would not be required to install technologies to comply with the proposed options.

[d] Positive non-zero value less than $50,000.

Source: U.S. EPA Analysis, 2004.

Table E3-9: Estimated Value of Non-Use Benefits Required for Total Benefits to Equal Total Social Costs for Existing Phase III Facilities - Break-Even Analysis by Regions (2003$, discounted at 7%)

Option	Total Social Costs (millions)	Mean Value of Use Benefits (millions)	Non-Use Benefits Necessary to Break Even[a] (millions)	Number of Households	Break-Even WTP per Household ($)	Reduction of I&E Losses (Age-1 Equivalents)	Break-Even Value per Age-1 Equivalent[b] ($)
50 MGD All							
California	$1.0	$0.0[d]	$0.9	1,166,416	$0.81	383,000	$2.48
North Atlantic	$5.0	$0.1	$5.0	2,129,180	$2.35	930,000	$5.37
Mid-Atlantic	$2.4	$0.4	$2.0	5,887,031	$0.35	13,400,000	$0.15
South Atlantic[c]	$0.0	$0.0	$0.0	0	$0.00	0	$0.00
Gulf of Mexico	$10.2	$0.5	$9.7	1,322,480	$7.34	8,380,000	$1.16
Great Lakes	$10.2	$0.3	$9.9	4,064,660	$2.45	11,600,000	$0.86
Inland	$20.6	$0.3	$20.4	8,214,682	$2.48	14,800,000	$1.38
National Total	**$50.1**	**$1.5**	**$48.6**	**22,784,450**	**$2.13**	**49,493,000**	**$0.98**
200 MGD All							
California	$0.0	$0.0	$0.0	0	$0.00	0	$0.00
North Atlantic	$0.5	$0.0[d]	$0.5	1,699,855	$0.27	198,000	$2.28
Mid-Atlantic	$1.8	$0.4	$1.4	5,603,551	$0.25	11,900,000	$0.12
South Atlantic[c]	$0.0	$0.0	$0.0	0	$0.00	0	$0.00
Gulf of Mexico	$4.4	$0.3	$4.1	251,666	$16.31	4,580,000	$0.90
Great Lakes	$3.7	$0.2	$3.5	2,388,297	$1.47	7,710,000	$0.45
Inland	$13.7	$0.2	$13.5	1,580,998	$8.56	9,650,000	$1.40
National Total	**$24.1**	**$1.0**	**$23.1**	**11,524,368**	**$2.01**	**34,038,000**	**$0.68**
100 MGD CWB							
California	$0.0	$0.0	$0.0	0	$0.00	0	$0.00
North Atlantic	$2.0	$0.0[d]	$2.0	1,989,096	$0.99	754,000	$2.62
Mid-Atlantic	$1.8	$0.4	$1.4	5,603,551	$0.25	11,900,000	$0.12
South Atlantic[c]	$0.0	$0.0	$0.0	0	$0.00	0	$0.00
Gulf of Mexico	$10.2	$0.5	$9.7	1,322,480	$7.34	8,380,000	$1.16
Great Lakes	$4.1	$0.2	$3.9	2,413,114	$1.62	8,740,000	$0.45
Inland	$0.0	$0.0	$0.0	0	$0.00	0	$0.00
National Total	**$18.3**	**$1.1**	**$17.2**	**11,328,241**	**$1.52**	**29,774,000**	**$0.58**

[a] 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.

[b] The non-use value per age-1 equivalent reported in the table includes the value placed on the fish's contribution to non-use ecological services (e.g., population, health, sustainability, and overall ecosystem health).

[c] No benefits or costs are expected in the South Atlantic region because all potentially regulated facilities in this region withdraw less than 50 MGD and therefore would not be required to install technologies to comply with the proposed options.

[d] Positive non-zero value less than $50,000.

Source: U.S. EPA Analysis, 2004.

GLOSSARY

opportunity cost: The lost value of alternative uses of resources (capital, labor, and raw materials) used in regulatory compliance.

social cost: The costs incurred by society as a whole as a result of the proposed rule. Social costs do not include costs that are transfers among parties that do not represent a new cost overall.

REFERENCES

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Appendix to Chapter E3

INTRODUCTION

APPENDIX CONTENTS

This appendix presents results from EPA's analysis of the benefits and costs of the 316(b) Phase III regulation for five additional options evaluated for Phase III existing facilities. Results are presented for the comparison of benefits and costs and the breakeven assessment of non-use benefits. As discussed previously in Chapter E3, the benefit and cost values presented in this appendix pertain only to the Manufacturers and Electric Generators segments of the industries subject to Phase III regulation.

EPA estimated the compliance response for each facility under each of the other options (see Table E3A-1, below). In this table and the following tables, the options are listed in order of increasing cost, which reflects the breadth of regulatory coverage based on design intake flow applicability threshold and the stringency of compliance requirements. For a description of this analysis, see section E3-1 above.

Table E3A-1: Number of Existing Phase III Facilities by Compliance Action[a]

Facility Compliance Action	Option 3	Option 4	Option 2	Option 1	Option 6
Total Facilities Potentially Subject to Regulation (excluding baseline closures)	**603**	**603**	**603**	**603**	**603**
Facilities Subject to Best Professional Judgment	235	415	235	251	0
Facilities Subject to National Categorical Requirements	368	189	368	353	603
No compliance action[b]	*202*	*59*	*184*	*160*	*317*
Impingement controls only	*100*	*39*	*93*	*73*	*114*
Impingement and entrainment controls	*66*	*91*	*91*	*120*	*172*

[a] Alternative less stringent requirements based on a site-specific assessment of costs, or costs and benefits, are allowed. The estimate of number of facilities meeting specific requirements is uncertain because the number of facilities requesting alternative less stringent requirements based on site-specific assessments is unknown.
[b] These facilities already meet compliance requirements.

Source: U.S. EPA Analysis, 2004.

E3A-1 COMPARISON OF BENEFITS AND SOCIAL COSTS BY OPTION

Table E3A-2 on the following page reports benefits, costs, and net benefits for all five other options. For further information on this analysis, see section E3-1, above.

Table E3A-2: Total Benefits, Social Costs, and Net Benefits for Existing Phase III Facilities by Option (millions; 2003$)

Option	Total Monetized Use Benefits[a]			Total Social Costs	Net Benefits Based on Use Benefits Only[b]		
	Low	Mean	High		Low	Mean	High
3% Discount Rate							
Option 3	$1.0	$2.0	$4.0	$65.0	($64.0)	($63.1)	($61.0)
Option 4	$1.0	$2.0	$4.1	$67.9	($66.9)	($65.9)	($63.8)
Option 2	$1.0	$2.0	$4.1	$73.7	($72.6)	($71.7)	($69.6)
Option 1	$1.1	$2.1	$4.1	$76.1	($75.0)	($74.0)	($71.9)
Option 6	$1.1	$2.1	$4.2	$95.7	($94.6)	($93.6)	($91.5)
7% Discount Rate							
Option 3	$0.8	$1.6	$3.2	$69.6	($68.8)	($68.0)	($66.4)
Option 4	$0.8	$1.6	$3.2	$73.9	($73.1)	($72.3)	($70.7)
Option 2	$0.8	$1.6	$3.2	$79.3	($78.5)	($77.7)	($76.1)
Option 1	$0.8	$1.6	$3.3	$81.8	($80.9)	($80.1)	($78.5)
Option 6	$0.9	$1.7	$3.3	$102.5	($101.6)	($100.8)	($99.1)

[a] The total monetizable value of I&E reductions includes use benefits only. EPA evaluated non-use benefits only qualitatively. The range (low, mean, and high) of annualized use values is computed by adding the high end value for commercial fishing benefits (based on assumed producer surplus of 40% of gross revenue) to the low, mean, and high values from recreational fishing benefits, respectively (see Chapter A4 of the RBA).

[b] Net benefits are computed by subtracting total annualized costs from total annual use benefits. The net benefits presented here are based on the comparison of a substantially complete measure of social costs with an incomplete measure of benefits and should be interpreted with caution.

Source: U.S. EPA Analysis, 2004.

Tables E3A-3 and E3A-4, below and following page, report net benefits, by option and benefit study region for, respectively, the 3% and 7% discount rate calculations. For further information on this analysis, see section E3-1, above.

Table E3A-3: Total Net Benefits for Existing Phase III Facilities by Option and Region (millions; 2003$, discounted at 3%)

Option	Net Benefits Based on Use Benefits Only[a]							
	California	North Atlantic	Mid-Atlantic	South Atlantic[b]	Gulf of Mexico	Great Lakes	Inland	National Total
Low								
Option 3	($1.1)	($4.5)	($2.5)	$0.0	($9.2)	($20.4)	($25.0)	($64.0)
Option 4	($1.5)	($4.5)	($3.0)	$0.0	($14.2)	($22.6)	($19.5)	($66.9)
Option 2	($1.5)	($4.5)	($3.0)	$0.0	($14.2)	($22.6)	($25.0)	($72.6)
Option 1	($1.5)	($4.5)	($3.0)	$0.0	($14.2)	($22.6)	($27.4)	($75.0)
Option 6	($2.2)	($4.5)	($3.2)	$0.0	($14.2)	($28.4)	($39.8)	($94.6)
Mean								
Option 3	($1.1)	($4.5)	($2.2)	$0.0	($8.9)	($20.2)	($24.8)	($63.1)
Option 4	($1.5)	($4.5)	($2.8)	$0.0	($13.8)	($22.5)	($19.4)	($65.9)
Option 2	($1.5)	($4.5)	($2.8)	$0.0	($13.8)	($22.5)	($24.9)	($71.7)
Option 1	($1.5)	($4.5)	($2.8)	$0.0	($13.8)	($22.5)	($27.2)	($74.0)
Option 6	($2.2)	($4.5)	($3.0)	$0.0	($13.8)	($28.2)	($39.6)	($93.6)
High								
Option 3	($1.1)	($4.4)	($1.6)	$0.0	($8.1)	($19.9)	($24.5)	($61.0)
Option 4	($1.4)	($4.4)	($2.2)	$0.0	($13.1)	($22.1)	($19.1)	($63.8)
Option 2	($1.4)	($4.4)	($2.2)	$0.0	($13.1)	($22.1)	($24.6)	($69.6)
Option 1	($1.4)	($4.4)	($2.2)	$0.0	($13.1)	($22.1)	($26.9)	($71.9)
Option 6	($2.1)	($4.4)	($2.4)	$0.0	($13.1)	($27.8)	($39.3)	($91.5)

[a] Net benefits are computed by subtracting total annualized costs from total annual use benefits. The net benefits presented here are based on the comparison of a substantially complete measure of social costs with an incomplete measure of benefits and should be interpreted with caution.

[b] No benefits or costs are expected in the South Atlantic region because all potentially regulated facilities in this region already meet the national categorical requirements in the baseline and therefore would not be required to install technologies to comply with this option.

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

Table E3A-4: Total Net Benefits for Existing Phase III Facilities by Option and Region (millions; 2003$, discounted at 7%)

Option	Net Benefits Based on Use Benefits Only[a]							
	California	North Atlantic	Mid-Atlantic	South Atlantic[b]	Gulf of Mexico	Great Lakes	Inland	National Total
Low								
Option 3	($1.2)	($5.0)	($2.4)	$0.0	($10.4)	($22.7)	($25.7)	($68.8)
Option 4	($1.6)	($5.0)	($2.9)	$0.0	($16.7)	($24.8)	($20.5)	($73.1)
Option 2	($1.6)	($5.0)	($2.9)	$0.0	($16.7)	($24.8)	($25.7)	($78.5)
Option 1	($1.6)	($5.0)	($2.9)	$0.0	($16.7)	($24.8)	($28.1)	($80.9)
Option 6	($2.2)	($5.0)	($3.1)	$0.0	($16.7)	($30.7)	($41.6)	($101.6)
Mean								
Option 3	($1.2)	($5.0)	($2.2)	$0.0	($10.1)	($22.6)	($25.6)	($68.0)
Option 4	($1.6)	($5.0)	($2.7)	$0.0	($16.5)	($24.7)	($20.4)	($72.3)
Option 2	($1.6)	($5.0)	($2.7)	$0.0	($16.5)	($24.7)	($25.6)	($77.7)
Option 1	($1.6)	($5.0)	($2.7)	$0.0	($16.5)	($24.7)	($28.0)	($80.1)
Option 6	($2.2)	($5.0)	($2.9)	$0.0	($16.5)	($30.5)	($41.4)	($100.8)
High								
Option 3	($1.2)	($4.9)	($1.8)	$0.0	($9.6)	($22.3)	($25.4)	($66.4)
Option 4	($1.5)	($4.9)	($2.3)	$0.0	($15.9)	($24.4)	($20.2)	($70.7)
Option 2	($1.5)	($4.9)	($2.3)	$0.0	($15.9)	($24.4)	($25.4)	($76.1)
Option 1	($1.5)	($4.9)	($2.3)	$0.0	($15.9)	($24.4)	($27.7)	($78.5)
Option 6	($2.1)	($4.9)	($2.4)	$0.0	($15.9)	($30.2)	($41.2)	($99.1)

[a] Net benefits are computed by subtracting total annualized costs from total annual use benefits. The net benefits presented here are based on the comparison of a substantially complete measure of social costs with an incomplete measure of benefits and should be interpreted with caution.

[b] No benefits or costs are expected in the South Atlantic region because all potentially regulated facilities in this region already meet the national categorical requirements in the baseline and therefore would not be required to install technologies to comply with this option.

Source: U.S. EPA Analysis, 2004.

Tables E3A-5 and E3A-6 compile the time profiles of benefits and costs for the five other options. The tables also report the calculated present and annualized values of benefits and costs at 3% and 7% discount rates.

Table E3A-5: Time Profile of Benefits and Costs for Existing Phase III Facilities for Options 3, 4, and 2 (millions; 2003$)

Year	Option 3		Option 4		Option 2	
	Monetized Benefits	Total Cost (excl. O&G)	Monetized Benefits	Total Cost (excl. O&G)	Monetized Benefits	Total Cost (excl. O&G)
2007	$0.00	$3.9	$0.00	$3.3	$0.00	$3.9
2008	$0.00	$14.9	$0.00	$13.9	$0.00	$16.0
2009	$0.00	$24.8	$0.00	$23.0	$0.00	$27.4
2010	$0.01	$188.0	$0.01	$182.6	$0.01	$191.4
2011	$0.05	$196.1	$0.06	$296.5	$0.06	$305.5
2012	$0.23	$281.5	$0.23	$284.6	$0.23	$291.2
2013	$0.64	$119.0	$0.65	$117.7	$0.65	$124.1
2014	$1.35	$31.0	$1.36	$27.0	$1.36	$34.4
2015	$1.91	$30.6	$1.92	$29.9	$1.92	$33.6
2016	$2.23	$29.1	$2.25	$26.8	$2.25	$32.7
2017	$2.34	$25.9	$2.36	$24.8	$2.36	$28.8
2018	$2.39	$20.4	$2.41	$20.7	$2.41	$24.2
2019	$2.40	$25.0	$2.43	$22.6	$2.43	$27.3
2020	$2.40	$55.1	$2.43	$51.8	$2.43	$58.2
2021	$2.40	$95.6	$2.43	$91.9	$2.43	$100.0
2022	$2.40	$39.4	$2.43	$40.8	$2.43	$46.6
2023	$2.40	$66.1	$2.43	$65.2	$2.43	$71.4
2024	$2.40	$30.6	$2.43	$26.6	$2.43	$33.9
2025	$2.40	$30.6	$2.43	$29.9	$2.43	$33.6
2026	$2.40	$29.1	$2.43	$26.8	$2.43	$32.7
2027	$2.40	$25.9	$2.43	$24.8	$2.43	$28.8
2028	$2.40	$20.4	$2.43	$20.7	$2.43	$24.2
2029	$2.40	$25.0	$2.43	$22.6	$2.43	$27.3
2030	$2.40	$55.1	$2.43	$51.8	$2.43	$58.2
2031	$2.40	$95.6	$2.43	$91.9	$2.43	$100.0
2032	$2.40	$39.4	$2.43	$40.8	$2.43	$46.6
2033	$2.40	$66.1	$2.43	$65.2	$2.43	$71.4
2034	$2.40	$30.6	$2.43	$26.6	$2.43	$33.9
2035	$2.40	$30.6	$2.43	$29.9	$2.43	$33.6
2036	$2.40	$29.1	$2.43	$26.8	$2.43	$32.7
2037	$2.40	$25.9	$2.43	$24.8	$2.43	$28.8
2038	$2.40	$20.4	$2.43	$20.7	$2.43	$24.2
2039	$2.40	$18.3	$2.43	$18.0	$2.43	$20.7
2040	$2.39	$15.3	$2.42	$15.7	$2.42	$17.6
2041	$2.35	$8.8	$2.37	$8.7	$2.37	$10.3
2042	$2.17	$5.3	$2.19	$5.2	$2.19	$6.2
2043	$1.76	$1.0	$1.78	$0.9	$1.78	$1.3
2044	$1.06	$0.0	$1.07	$0.0	$1.07	$0.0
2045	$0.49	$0.0	$0.50	$0.0	$0.50	$0.0
2046	$0.18	$0.0	$0.18	$0.0	$0.18	$0.0
2047	$0.06	$0.0	$0.07	$0.0	$0.07	$0.0
2048	$0.02	$0.0	$0.02	$0.0	$0.02	$0.0
PV 3%	**$39.06**	**$1,313.2**	**$39.48**	**$1,371.2**	**$39.48**	**$1,487.3**
Annualized 3%	**$1.99**	**$65.0**	**$2.01**	**$67.9**	**$2.01**	**$73.7**
PV 7%	**$19.48**	**$923.8**	**$19.69**	**$980.8**	**$19.69**	**$1,053.3**
Annualized 7%	**$1.57**	**$69.6**	**$1.59**	**$73.9**	**$1.59**	**$79.3**

Source: U.S. EPA Analysis, 2004.

Table E3A-6: Time Profile of Benefits and Costs for Existing Phase III Facilities for Options 1 and 6 (millions; 2003$)

Year	Option 1		Option 6	
	Monetized Benefits	Total Cost (excl. O&G)	Monetized Benefits	Total Cost (excl. O&G)
2007	$0.00	$3.9	$0.00	$6.0
2008	$0.00	$16.1	$0.00	$23.8
2009	$0.00	$27.9	$0.00	$38.7
2010	$0.01	$206.0	$0.01	$266.2
2011	$0.06	$306.9	$0.06	$410.1
2012	$0.24	$295.9	$0.25	$316.7
2013	$0.67	$125.3	$0.69	$137.6
2014	$1.39	$36.1	$1.42	$49.6
2015	$1.96	$34.9	$2.00	$46.8
2016	$2.29	$34.5	$2.34	$44.5
2017	$2.41	$30.2	$2.46	$41.1
2018	$2.46	$25.4	$2.51	$35.5
2019	$2.47	$28.6	$2.53	$39.6
2020	$2.47	$61.7	$2.53	$76.5
2021	$2.47	$101.8	$2.53	$129.5
2022	$2.47	$51.2	$2.53	$69.7
2023	$2.47	$72.7	$2.53	$84.3
2024	$2.47	$35.0	$2.53	$47.7
2025	$2.47	$34.9	$2.53	$46.7
2026	$2.47	$34.5	$2.53	$44.5
2027	$2.47	$30.2	$2.53	$41.1
2028	$2.47	$25.4	$2.53	$35.5
2029	$2.47	$28.6	$2.53	$39.6
2030	$2.47	$61.7	$2.53	$76.5
2031	$2.47	$101.8	$2.53	$129.5
2032	$2.47	$51.2	$2.53	$69.7
2033	$2.47	$72.7	$2.53	$84.3
2034	$2.47	$35.0	$2.53	$47.7
2035	$2.47	$34.9	$2.53	$46.7
2036	$2.47	$34.5	$2.53	$44.5
2037	$2.47	$30.2	$2.53	$41.1
2038	$2.47	$25.4	$2.53	$35.5
2039	$2.47	$21.9	$2.53	$28.7
2040	$2.47	$18.6	$2.52	$23.6
2041	$2.42	$11.4	$2.47	$14.2
2042	$2.23	$6.2	$2.27	$8.1
2043	$1.81	$1.4	$1.84	$2.2
2044	$1.09	$0.0	$1.11	$0.0
2045	$0.51	$0.0	$0.53	$0.0
2046	$0.18	$0.0	$0.19	$0.0
2047	$0.07	$0.0	$0.07	$0.0
2048	$0.02	$0.0	$0.02	$0.0
PV 3%	**$40.23**	**$1,535.7**	**$41.12**	**$1,932.0**
Annualized 3%	**$2.05**	**$76.1**	**$2.10**	**$95.7**
PV 7%	**$20.07**	**$1,085.6**	**$20.52**	**$1,360.3**
Annualized 7%	**$1.62**	**$81.8**	**$1.65**	**$102.5**

Source: U.S. EPA Analysis, 2004.

E3A-2 INCREMENTAL ANALYSIS OF BENEFITS AND SOCIAL COSTS

EPA conducted an incremental analysis of benefits and social costs to determine as increasingly more costly options are considered, by what amount do benefits, costs, and net benefits change from option to option. Table E3A-7, below, reports this analysis for the five other options evaluated. For a description of this analysis, see section E3-2 above.

Table E3A-7: Incremental Benefit-Cost Analysis for Existing Phase III Facilities (millions; 2003$)

Option[a]	Net Benefits Based on Use Benefits Only[b]			Incremental Net Benefits[c]		
	Low	Mean	High	Low	Mean	High
3% discount rate						
Option 3	($64.0)	($63.1)	($61.0)	n/a	n/a	n/a
Option 4	($66.9)	($65.9)	($63.8)	($2.9)	($2.9)	($2.8)
Option 2	($72.6)	($71.7)	($69.6)	($5.8)	($5.8)	($5.8)
Option 1	($75.0)	($74.0)	($71.9)	($2.4)	($2.4)	($2.6)
Option 6	($94.6)	($93.6)	($91.5)	($19.6)	($19.6)	($19.5)
7% discount rate						
Option 3	($68.8)	($68.0)	($66.4)	n/a	n/a	n/a
Option 4	($73.1)	($72.3)	($70.7)	($4.3)	($4.3)	($4.3)
Option 2	($78.5)	($77.7)	($76.1)	($5.5)	($5.5)	($5.5)
Option 1	($80.9)	($80.1)	($78.5)	($2.4)	($2.4)	($2.4)
Option 6	($101.6)	($100.8)	($99.1)	($20.7)	($20.7)	($20.6)

[a] Options are presented in order of increasing applicability, based on the number of facilities regulated.
[b] Net benefits are computed by subtracting total annualized costs from total annual use benefits. The net benefits presented here are based on the comparison of a substantially complete measure of social costs with an incomplete measure of benefits and should be interpreted with caution.
[c] Incremental net benefits are equal to the difference between net benefits of a given option and the net benefits of the previous less stringent option.

Source: U.S. EPA Analysis, 2004.

E3A-3 BREAK-EVEN ANALYSIS OF POTENTIAL NON-USE BENEFITS

EPA conducted a break-even analysis for each option to determine the per household value and per age-1 equivalent value of non-use benefits needed for total annual benefits to equal total annual costs. Table E3A-8 presents the results at the national level; Tables E3A-9 and E3A-10 present results at the regional level. For a description of this analysis, see section E3-3 above.

Table E3A-8: Estimated Value of Non-Use Benefits Required for Total Benefits to Equal Total Social Cost for Existing Phase III Facilities - Break-Even Analysis (2003$)

Option	Total Social Costs (millions)	Mean Value of Use Benefits (millions)	Non-Use Benefits Necessary to Break Even[a] (millions)	Number of Households	Break-Even WTP per Household ($)	Reduction in I&E Losses (Age-1 Equivalents)	Break-Even Value per Age-1 Equivalent[b] ($)
			3% Discount Rate				
Option 3	$65.0	$2.0	$63.1	31,890,286	$1.98	53,171,000	$1.19
Option 4	$67.9	$2.0	$65.9	26,772,975	$2.46	52,261,000	$1.26
Option 2	$73.7	$2.0	$71.7	26,772,975	$2.68	52,261,000	$1.37
Option 1	$76.1	$2.1	$74.0	32,298,995	$2.29	54,361,000	$1.36
Option 6	$95.7	$2.1	$93.6	38,143,532	$2.45	56,161,000	$1.67
			7% Discount Rate				
Option 3	$69.6	$1.6	$68.0	31,890,286	$2.13	53,171,000	$1.28
Option 4	$73.9	$1.6	$72.3	26,772,975	$2.70	52,261,000	$1.38
Option 2	$79.3	$1.6	$77.7	26,772,975	$2.90	52,261,000	$1.49
Option 1	$81.8	$1.6	$80.1	32,298,995	$2.48	54,361,000	$1.47
Option 6	$102.5	$1.7	$100.8	38,143,532	$2.64	56,161,000	$1.79

[a] 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.

[b] The non-use value per age-1 equivalent reported in the table includes the value placed on the fish's contribution to non-use ecological services (e.g., population, health, sustainability, and overall ecosystem health).

Source: U.S. EPA Analysis, 2004.

Table E3A-9: Estimated Value of Non-Use Benefits Required for Total Benefits to Equal Total Social Costs for Existing Phase III Facilities - Break-Even Analysis by Regions (2003$, discounted at 3%)

Option	Total Social Costs (millions)	Mean Value of Use Benefits (millions)	Non-Use Benefits Necessary to Break Even[a] (millions)	Number of Households	Break-Even WTP per Household ($)	Reduction of I&E Losses (Age-1 Equivalents)	Break-Even Value per Age-1 Equivalent[b] ($)
Option 3							
California	$1.1	$0.0[d]	$1.1	1,518,773	$0.71	391,000	$2.76
North Atlantic	$4.6	$0.1	$4.5	2,129,180	$2.11	930,000	$4.84
Mid-Atlantic	$2.7	$0.5	$2.2	6,491,544	$0.34	13,400,000	$0.16
South Atlantic[c]	$0.0	$0.0	$0.0	0	$0.00	0	$0.00
Gulf of Mexico	$9.5	$0.7	$8.9	1,344,996	$6.59	8,650,000	$1.02
Great Lakes	$20.6	$0.4	$20.2	7,076,410	$2.86	13,200,000	$1.53
Inland	$25.2	$0.3	$24.8	13,329,383	$1.86	16,600,000	$1.50
National Total	**$65.0**	**$2.0**	**$63.1**	**31,890,286**	**$1.98**	**53,171,000**	**$1.19**
Option 4							
California	$1.5	$0.1	$1.5	1,518,773	$0.98	771,000	$1.93
North Atlantic	$4.6	$0.1	$4.5	2,129,180	$2.11	930,000	$4.84
Mid-Atlantic	$3.3	$0.5	$2.8	6,491,544	$0.43	13,600,000	$0.20
South Atlantic[c]	$0.0	$0.0	$0.0	0	$0.00	0	$0.00
Gulf of Mexico	$14.5	$0.7	$13.8	1,344,996	$10.28	8,860,000	$1.56
Great Lakes	$22.8	$0.4	$22.5	7,076,410	$3.17	13,300,000	$1.69
Inland	$19.7	$0.3	$19.4	8,212,072	$2.36	14,800,000	$1.31
National Total	**$67.9**	**$2.0**	**$65.9**	**26,772,975**	**$2.46**	**52,261,000**	**$1.26**
Option 2							
California	$1.5	$0.1	$1.5	1,518,773	$0.98	771,000	$1.93
North Atlantic	$4.6	$0.1	$4.5	2,129,180	$2.11	930,000	$4.84
Mid-Atlantic	$3.3	$0.5	$2.8	6,491,544	$0.43	13,600,000	$0.20
South Atlantic[c]	$0.0	$0.0	$0.0	0	$0.00	0	$0.00
Gulf of Mexico	$14.5	$0.7	$13.8	1,344,996	$10.28	8,860,000	$1.56
Great Lakes	$22.8	$0.4	$22.5	7,076,410	$3.17	13,300,000	$1.69
Inland	$25.2	$0.3	$24.9	8,212,072	$3.03	14,800,000	$1.68
National Total	**$73.7**	**$2.0**	**$71.7**	**26,772,975**	**$2.68**	**52,261,000**	**$1.37**
Option 1							
California	$1.5	$0.1	$1.5	1,518,773	$0.98	771,000	$1.93

Table E3A-9: Estimated Value of Non-Use Benefits Required for Total Benefits to Equal Total Social Costs for Existing Phase III Facilities - Break-Even Analysis by Regions (2003$, discounted at 3%)

Option	Total Social Costs (millions)	Mean Value of Use Benefits (millions)	Non-Use Benefits Necessary to Break Even[a] (millions)	Number of Households	Break-Even WTP per Household ($)	Reduction of I&E Losses (Age-1 Equivalents)	Break-Even Value per Age-1 Equivalent[b] ($)
North Atlantic	$4.6	$0.1	$4.5	2,129,180	$2.11	930,000	$4.84
Mid-Atlantic	$3.3	$0.5	$2.8	6,491,544	$0.43	13,600,000	$0.20
South Atlantic[c]	$0.0	$0.0	$0.0	0	$0.00	0	$0.00
Gulf of Mexico	$14.5	$0.7	$13.8	1,344,996	$10.28	8,860,000	$1.56
Great Lakes	$22.8	$0.4	$22.5	7,076,410	$3.17	13,300,000	$1.69
Inland	$27.5	$0.3	$27.2	13,738,093	$1.98	16,900,000	$1.61
National Total	**$76.1**	**$2.1**	**$74.0**	**32,298,995**	**$2.29**	**54,361,000**	**$1.36**
			Option 6				
California	$2.2	$0.1	$2.2	1,518,773	$1.43	771,000	$2.82
North Atlantic	$4.6	$0.1	$4.5	2,129,180	$2.11	930,000	$4.84
Mid-Atlantic	$3.5	$0.5	$3.0	7,214,556	$0.41	13,700,000	$0.22
South Atlantic[c]	$0.0	$0.0	$0.0	0	$0.00	0	$0.00
Gulf of Mexico	$14.5	$0.7	$13.8	1,344,996	$10.28	8,860,000	$1.56
Great Lakes	$28.6	$0.4	$28.2	9,055,971	$3.11	14,300,000	$1.97
Inland	$40.0	$0.4	$39.6	16,880,055	$2.35	17,600,000	$2.25
National Total	**$95.7**	**$2.1**	**$93.6**	**38,143,532**	**$2.45**	**56,161,000**	**$1.67**

[a] 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.

[b] The non-use value per age-1 equivalent reported in the table includes the value placed on the fish's contribution to non-use ecological services (e.g., population, health, sustainability, and overall ecosystem health).

[c] No benefits or costs are expected in the South Atlantic region because all potentially regulated facilities in this region already meet the national categorical requirements in the baseline and therefore would not be required to install technologies to comply with this option.

[d] Positive non-zero value less than $50,000.

Source: U.S. EPA Analysis, 2004.

Table E3A-10: Estimated Value of Non-Use Benefits Required for Total Benefits to Equal Total Social Costs for Existing Phase III Facilities - Break-Even Analysis by Regions (2003$, discounted at 7%)

Option	Total Social Costs (millions)	Mean Value of Use Benefits (millions)	Non-Use Benefits Necessary to Break Even[a] (millions)	Number of Households	Break-Even WTP per Household ($)	Reduction of I&E Losses (Age-1 Equivalents)	Break-Even Value per Age-1 Equivalent[b] ($)
Option 3							
California	$1.2	$0.0[d]	$1.2	1,518,773	$0.79	391,000	$3.07
North Atlantic	$5.0	$0.1	$5.0	2,129,180	$2.35	930,000	$5.37
Mid-Atlantic	$2.6	$0.4	$2.2	6,491,544	$0.34	13,400,000	$0.16
South Atlantic[c]	$0.0	$0.0	$0.0	0	$0.00	0	$0.00
Gulf of Mexico	$10.7	$0.5	$10.1	1,344,996	$7.54	8,650,000	$1.17
Great Lakes	$22.9	$0.3	$22.6	7,076,410	$3.19	13,200,000	$1.71
Inland	$25.9	$0.3	$25.6	13,329,383	$1.92	16,600,000	$1.54
National Total	**$69.6**	**$1.6**	**$68.0**	**31,890,286**	**$2.13**	**53,171,000**	**$1.28**
Option 4							
California	$1.6	$0.0[d]	$1.6	1,518,773	$1.03	771,000	$2.03
North Atlantic	$5.0	$0.1	$5.0	2,129,180	$2.35	930,000	$5.37
Mid-Atlantic	$3.1	$0.4	$2.7	6,491,544	$0.42	13,600,000	$0.20
South Atlantic[c]	$0.0	$0.0	$0.0	0	$0.00	0	$0.00
Gulf of Mexico	$17.0	$0.5	$16.5	1,344,996	$12.25	8,860,000	$1.86
Great Lakes	$25.0	$0.3	$24.7	7,076,410	$3.49	13,300,000	$1.86
Inland	$20.6	$0.3	$20.4	8,212,072	$2.48	14,800,000	$1.38
National Total	**$73.9**	**$1.6**	**$72.3**	**26,772,975**	**$2.70**	**52,261,000**	**$1.38**
Option 2							
California	$1.6	$0.0[d]	$1.6	1,518,773	$1.03	771,000	$2.03
North Atlantic	$5.0	$0.1	$5.0	2,129,180	$2.35	930,000	$5.37
Mid-Atlantic	$3.1	$0.4	$2.7	6,491,544	$0.42	13,600,000	$0.20
South Atlantic[c]	$0.0	$0.0	$0.0	0	$0.00	0	$0.00
Gulf of Mexico	$17.0	$0.5	$16.5	1,344,996	$12.25	8,860,000	$1.86
Great Lakes	$25.0	$0.3	$24.7	7,076,410	$3.49	13,300,000	$1.86
Inland	$25.9	$0.3	$25.6	8,212,072	$3.12	14,800,000	$1.73
National Total	**$79.3**	**$1.6**	**$77.7**	**26,772,975**	**$2.90**	**52,261,000**	**$1.49**
Option 1							
California	$1.6	$0.0[d]	$1.6	1,518,773	$1.03	771,000	$2.03

Table E3A-10: Estimated Value of Non-Use Benefits Required for Total Benefits to Equal Total Social Costs for Existing Phase III Facilities - Break-Even Analysis by Regions (2003$, discounted at 7%)

Option	Total Social Costs (millions)	Mean Value of Use Benefits (millions)	Non-Use Benefits Necessary to Break Even[a] (millions)	Number of Households	Break-Even WTP per Household ($)	Reduction of I&E Losses (Age-1 Equivalents)	Break-Even Value per Age-1 Equivalent[b] ($)
North Atlantic	$5.0	$0.1	$5.0	2,129,180	$2.35	930,000	$5.37
Mid-Atlantic	$3.1	$0.4	$2.7	6,491,544	$0.42	13,600,000	$0.20
South Atlantic[c]	$0.0	$0.0	$0.0	0	$0.00	0	$0.00
Gulf of Mexico	$17.0	$0.5	$16.5	1,344,996	$12.25	8,860,000	$1.86
Great Lakes	$25.0	$0.3	$24.7	7,076,410	$3.49	13,300,000	$1.86
Inland	$28.3	$0.3	$28.0	13,738,093	$2.04	16,900,000	$1.66
National Total	**$81.8**	**$1.6**	**$80.1**	**32,298,995**	**$2.48**	**54,361,000**	**$1.47**
			Option 6				
California	$2.2	$0.0[d]	$2.2	1,518,773	$1.45	771,000	$2.85
North Atlantic	$5.0	$0.1	$5.0	2,129,180	$2.35	930,000	$5.37
Mid-Atlantic	$3.3	$0.4	$2.9	7,214,556	$0.40	13,700,000	$0.21
South Atlantic[c]	$0.0	$0.0	$0.0	0	$0.00	0	$0.00
Gulf of Mexico	$17.0	$0.5	$16.5	1,344,996	$12.25	8,860,000	$1.86
Great Lakes	$30.8	$0.3	$30.5	9,055,971	$3.37	14,300,000	$2.13
Inland	$41.7	$0.3	$41.4	16,880,055	$2.45	17,600,000	$2.35
National Total	**$102.5**	**$1.7**	**$100.8**	**38,143,532**	**$2.64**	**56,161,000**	**$1.79**

[a] 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.

[b] The non-use value per age-1 equivalent reported in the table includes the value placed on the fish's contribution to non-use ecological services (e.g., population, health, sustainability, and overall ecosystem health).

[c] No benefits or costs are expected in the South Atlantic region because all potentially regulated facilities in this region already meet the national categorical requirements in the baseline and therefore would not be required to install technologies to comply with this option.

[d] Positive non-zero value less than $50,000.

Source: U.S. EPA Analysis, 2004.