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 $\leq$ - 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.

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.

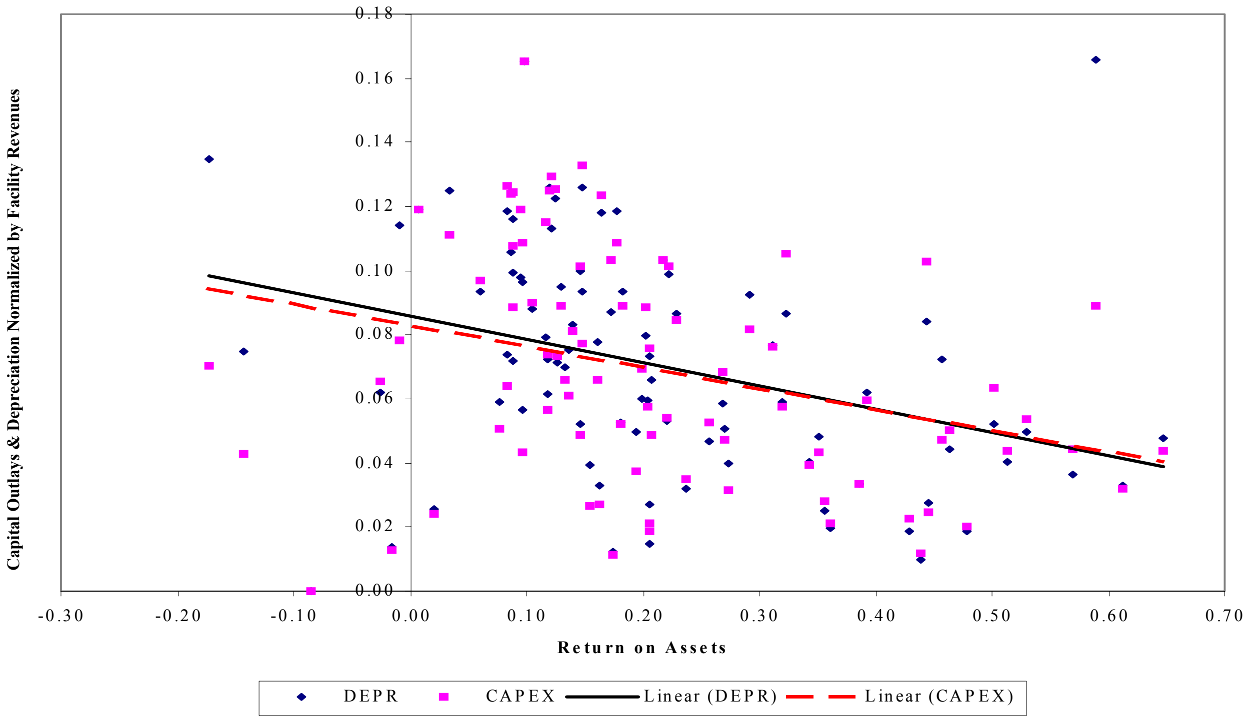
- The Petroleum and Coal Products (SIC 29) graph shows predicted capital expenditures exceeding depreciation over the ROA range analyzed. However, the extent of difference does not materially change as ROA increases.

- 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.

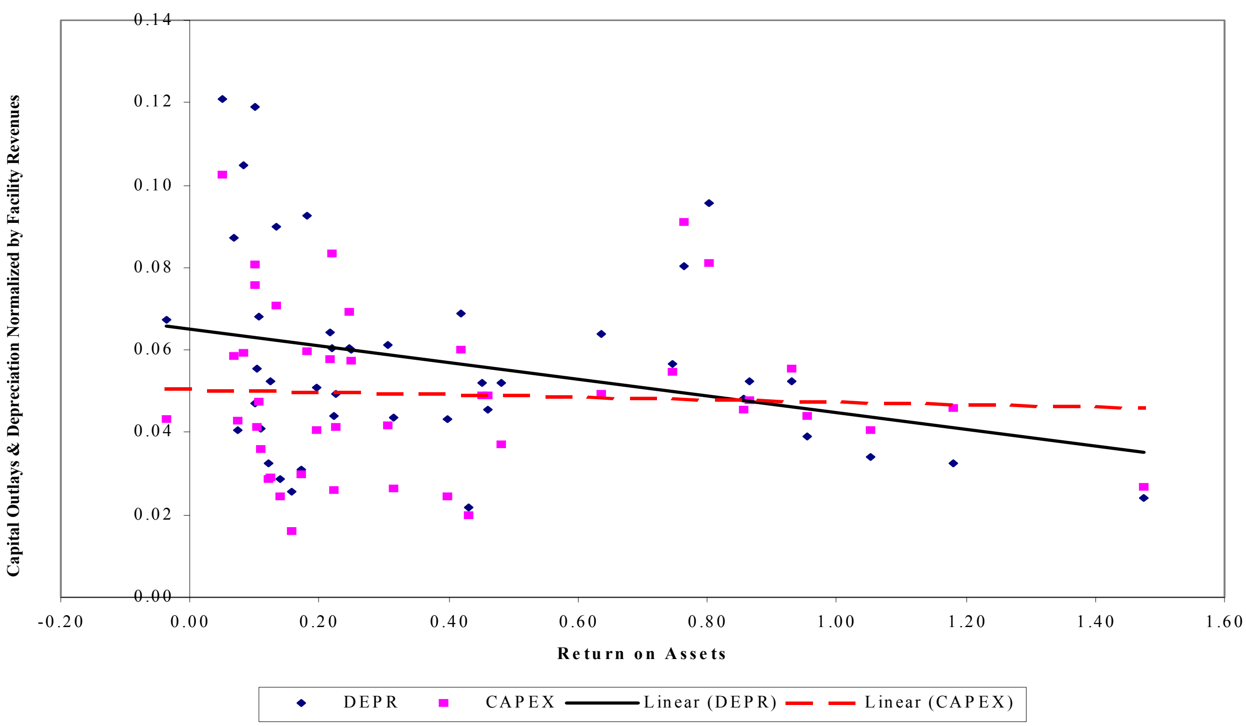
[4] For presentation purposes, two outlier facilities were excluded from the graph for SIC 28: Chemicals and allied products, and one outlier facility was excluded from the graph for SIC 26: Paper and allied products.

Figure B3A5.1: Comparison of Estimated Capital Outlays to Reported Depreciation for Phase III Survey Facilities in the Paper and Allied Products Sector



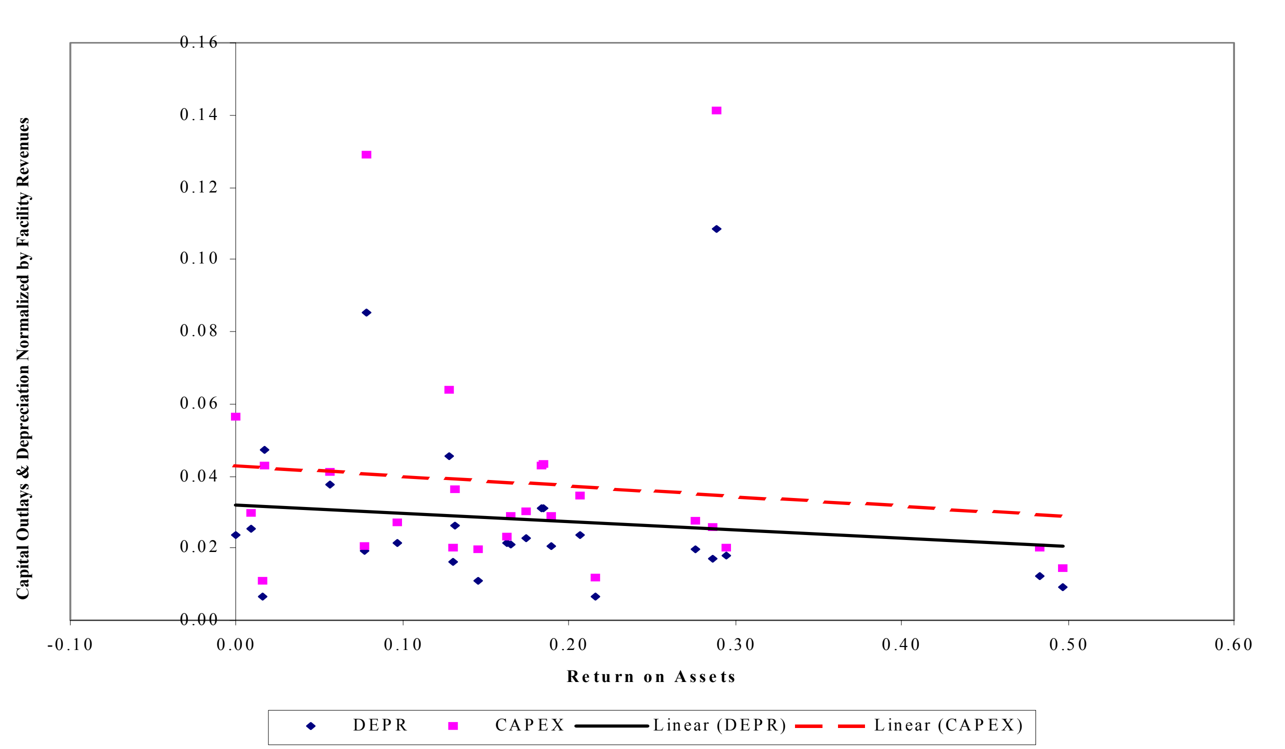
Source: U.S. EPA analysis, 2004.

Figure B3A5.2: Comparison of Estimated Capital Outlays to Reported Depreciation for Phase III Survey Facilities in the Chemicals and Allied Products Sector



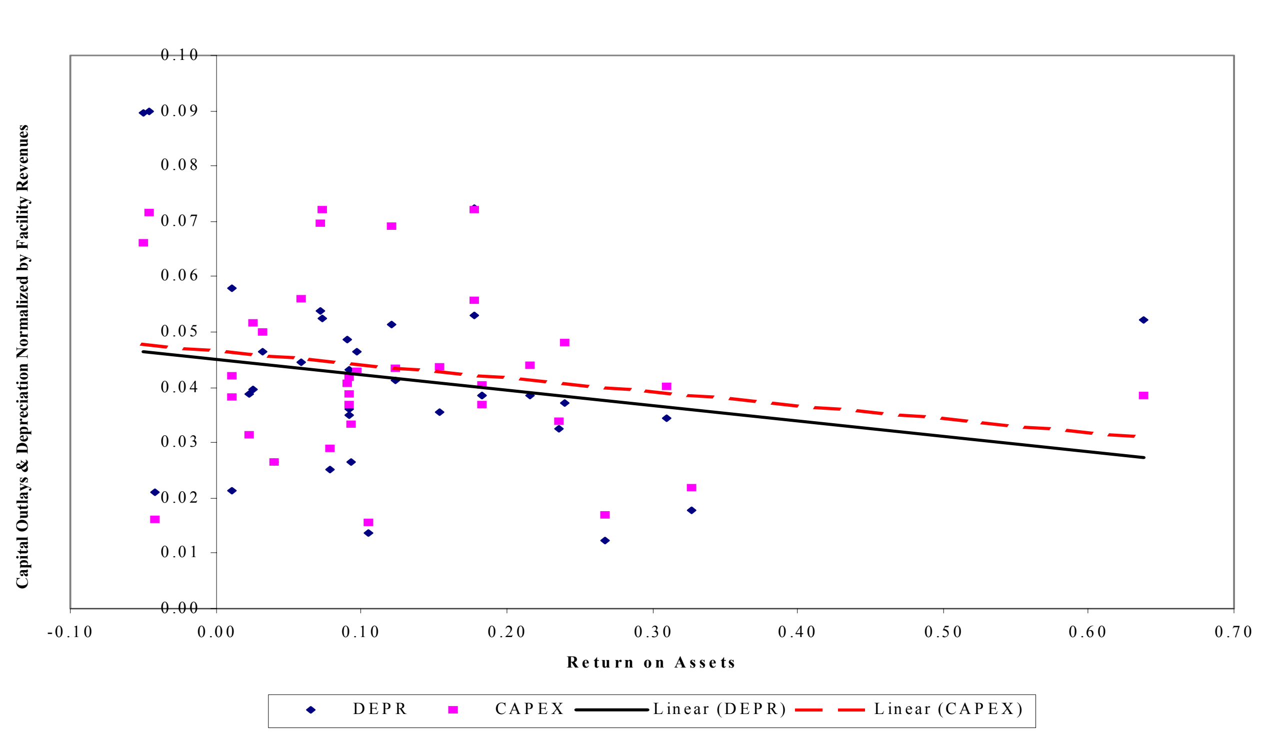
Source: U.S. EPA analysis, 2004.

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.

Chirinko, Robert S. 1993. "Business Fixed Investment Spending: A Critical Survey of Modeling Strategies, Empirical Results and Policy Implications." *Journal of Economic Literature* 31, no. 4: 1875-1911.

Goolsbee, Austan. 1997. "The Business Cycle, Financial Performance, and the Retirement of Capital Goods." University of Chicago, Graduate School of Business Working Paper.

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McCarthy, Jonathan. 2001. "Equipment Expenditures since 1995: The Boom and the Bust." *Current Issues In Economics And Finance* 7, no. 9: 1-6.

Opler, Tim and Lee Pinkowitz, Rene Stulz and Rohan Williamson. 1997. "The Determinants and Implications of Corporate Cash Holdings." Working paper, Ohio State University College of Business.

Tevlin, Stacey and Karl Whelan. 2000. "Explaining the Investment Boom of the 1990s." Board of Governors of the Federal Reserve System Finance and Economics Discussion Paper no. 2000-11

Uchitelle, Louis. 2001. "Wary Spending by Companies Cools Economy." *New York Times*, May 14, p. A1.

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.

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Risk Management Association (RMA). 2000-2001. *Annual Statement Studies*.

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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.

APPENDIX CONTENTS

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.

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Available at: http://www.sba.gov/ADVO/stats/data.html.

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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):

[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***".

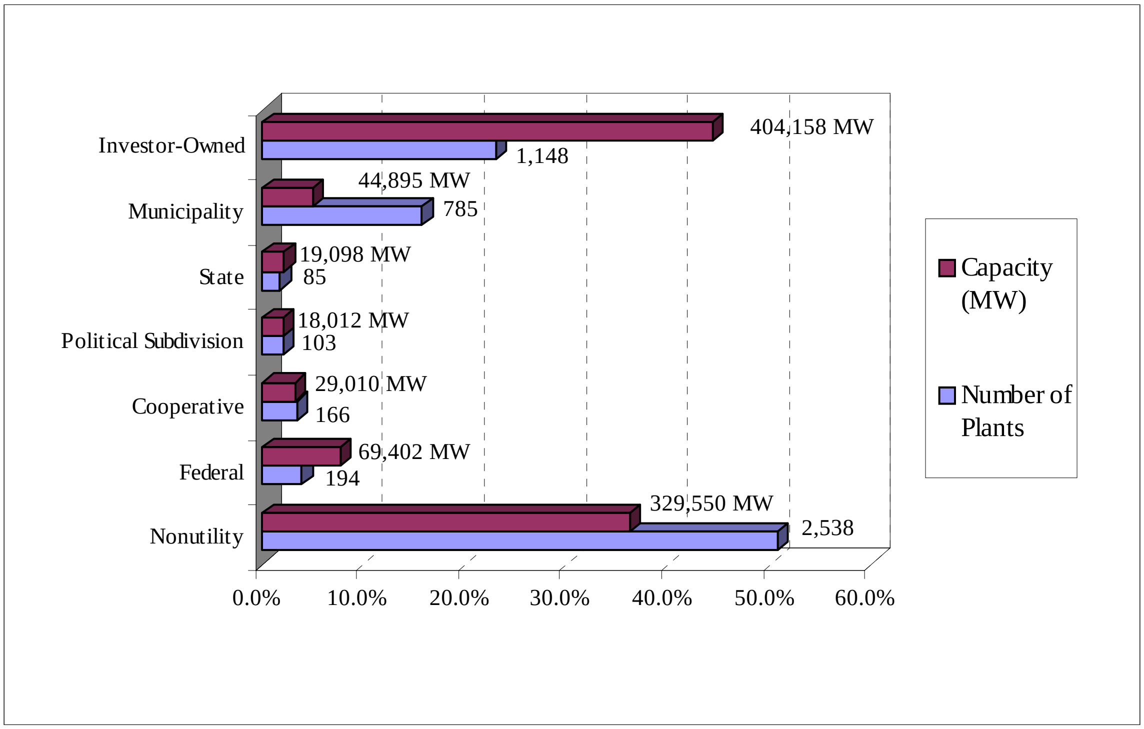
❖ *Nontraditional participants*

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

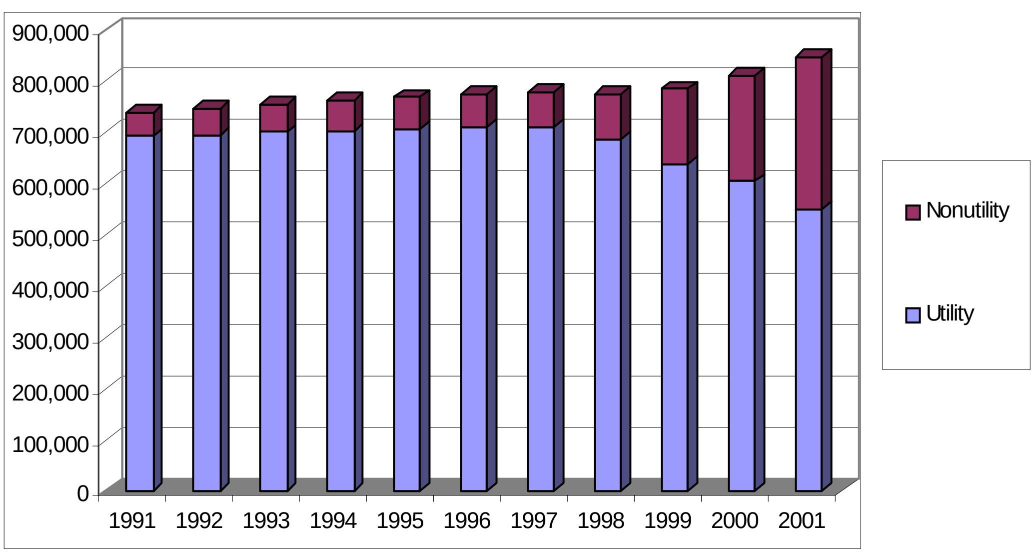
The rating of a generating unit is a measure of its ability to produce electricity. Generator ratings are expressed in megawatts (MW). Capacity and capability are the two common measures:

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%**

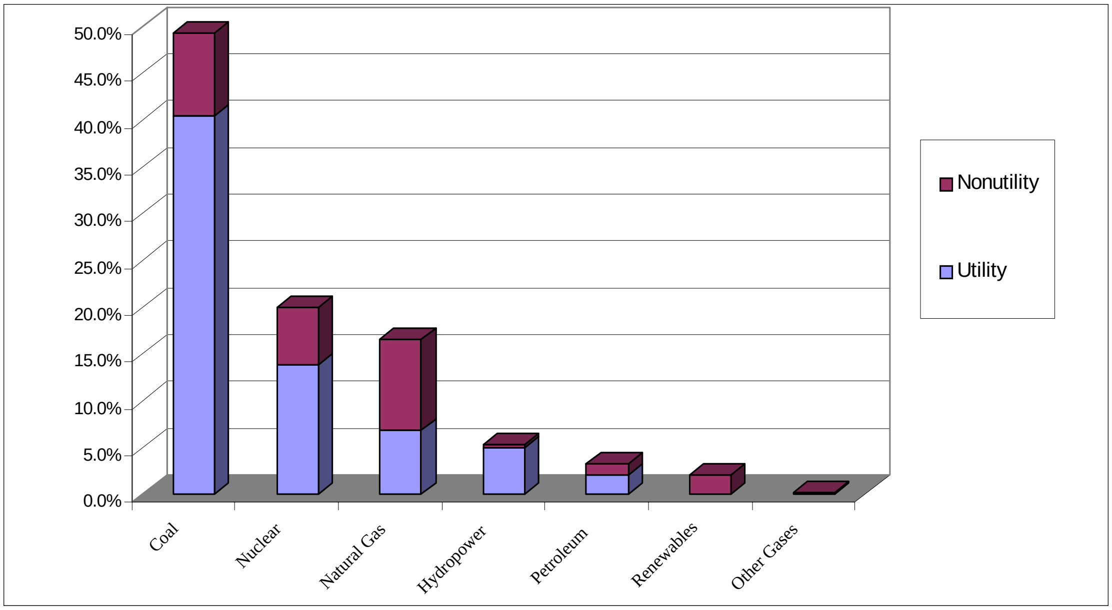
[a] Renewables include solar, wind, wood, biomass, and geothermal energy sources.
[b] Other includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies

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.

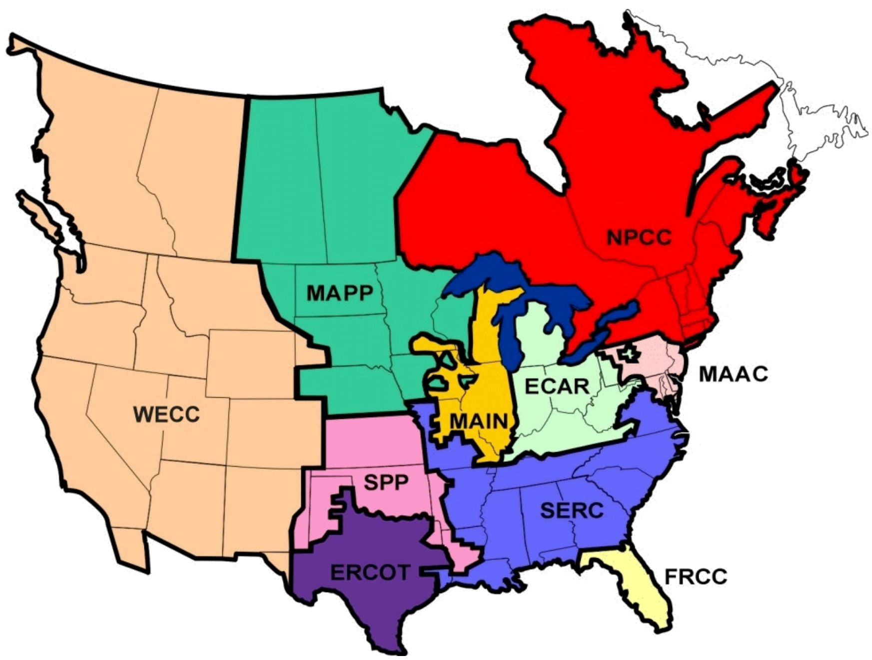
The North American Electric Reliability Council (NERC) is responsible for the overall reliability, planning, and coordination of the power grids. This voluntary organization was formed in 1968 by electric utilities, following a 1965 blackout in the Northeast. NERC is organized into ten regional councils 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%**

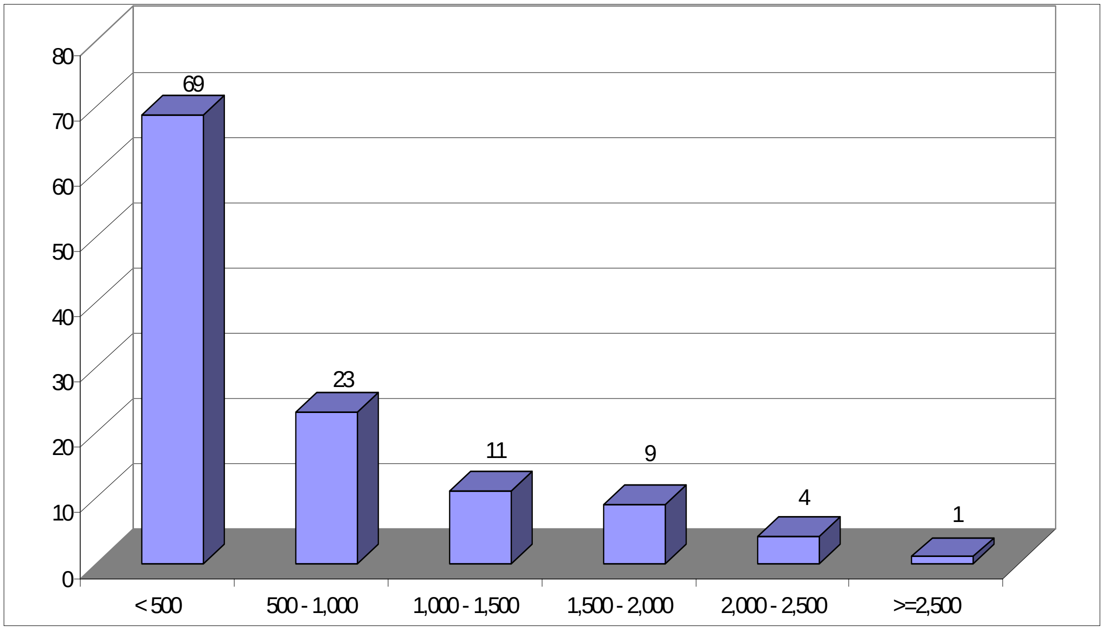
[a] The number of potential Phase III Electric Generators was sample weighted to account for survey non-respondents. Numbers may not add up to totals due to independent rounding.

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

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.

CHAPTER CONTENTS

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.

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[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

APPENDIX CONTENTS

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.

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.

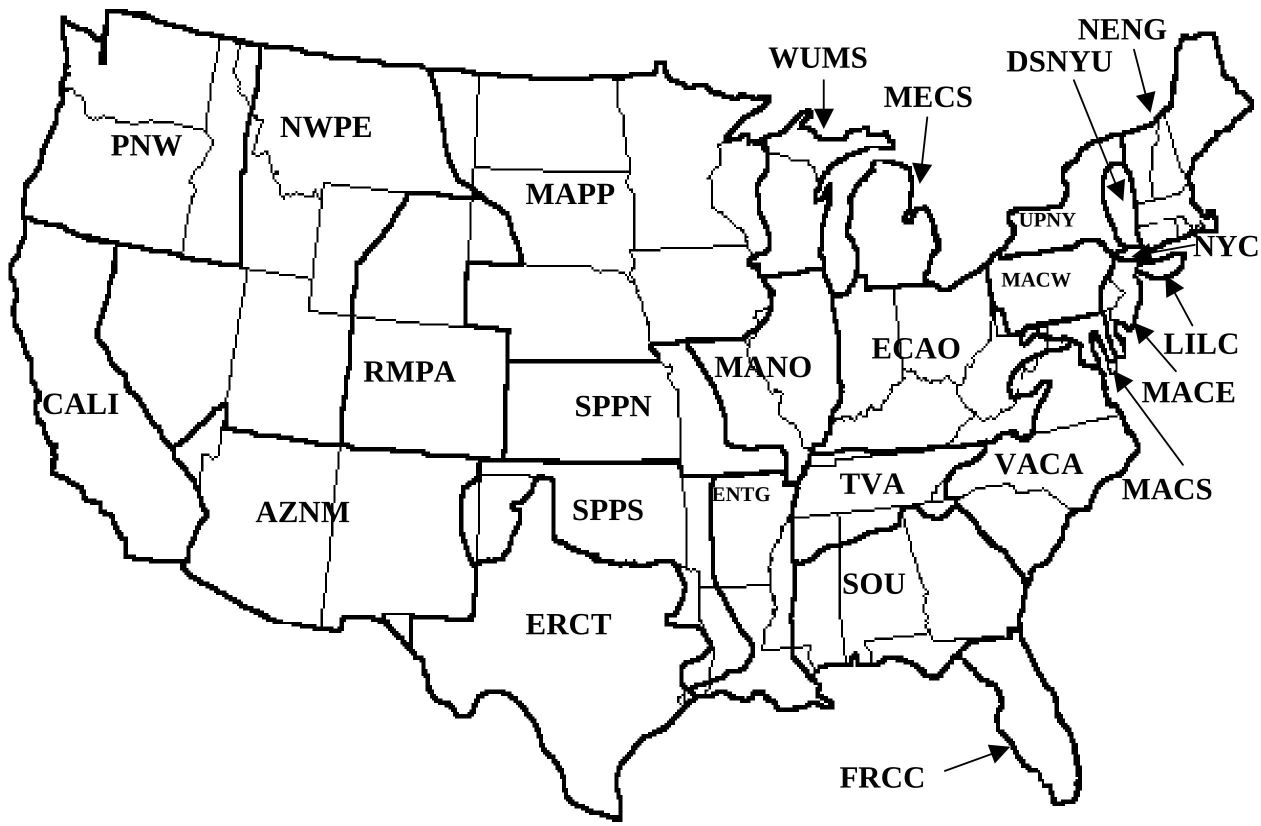
[3] EPA used the IPM® to forecast operational changes, including changes in capacity, generation, revenues, electricity prices, and plant closures, resulting from the rule. In other policy analyses, the IPM® is generally also used to determine the compliance response for each model facility. This process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

ID	Feature	Description	Doc. Report Section[1]
Power System Operations Assumptions			
1	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.	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.	3.1 4.2.6 Appendix A4.1
2	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.)	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.	3.2.1 3.2.2 Appendix A3.1
3	State Multi-Pollutant Regulations	Attachment C lists the state multipollutant programs incorporated in v.2.1.6.	3.9
4	New Source Review (NSR) Settlements	Attachment D shows the settlements under New Source Review provisions of the Clean Air Act that were included in v. 2.1.6.	3.9.3
5	State Renewable Energy Programs	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.	3.9.4 (Not covered)
6	State Renewable Portfolio Standards (RPS)	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.)	3.9.4 (Not covered)
7	Emission and removal rate assumptions for potential units.	The emission and removal rates are the same as in AEO 2003, i.e., — NOx Rates / SO2 Rates Conventional Pulverized Coal (CPC): 0.11 lb/mmBtu / 95% Removal Integrated Gasification Combined Cycle (IGCC): 0.02 lb/mmBtu / 99% Removal Combined Cycle (CC): 0.02 lb/mmBtu / — Combustion Turbine (CT): 0.08 lb/mmBtu / — 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.	3.9.5

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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