United States
Environmental Protection
Agency

Economic Analysis for Existing and New Projects in the Coalbed Methane Industry

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Introduction

In 2007, EPA began a detailed study of the coalbed methane (CBM) extraction industry and collected data on the industry through: (1) meetings with stakeholders, (2) site visits, and (3) the *Detailed Questionnaire Coalbed Methane Extraction Sector* and the *2008 Coalbed Methane Industry Screener* (Detailed Questionnaire and Screener Questionnaire or CBM survey). The report, *Coalbed Methane Extraction: Detailed Study Report* (Detailed Study Report) dated December 2010 presented EPA's initial technical and economic industry profile and EPA's preliminary review of the information collected as part of the detailed study. Based on this detailed study, EPA announced in the final 2010 Effluent Guidelines Program Plan, its plan to develop effluent limitations guidelines and standards (ELGs) for the CBM extraction industry. Following its announcement to undertake the rulemaking, EPA continued analyzing the information collected from the CBM industry and also collected and analyzed more current data. Some of EPA's findings have changed since EPA selected this industry for rulemaking. To update the public on technical aspects, EPA developed the *Technical Development Document for the Coalbed Methane Extraction Industry* dated March 2013 (Technical Development Document) (DCN CBM00669). EPA used the information provided in the *Technical Development Document* to develop the economic analysis described in this document.

This document describes the economic analysis that EPA conducted since initiating the CBM rulemaking, including methodology, data, and results. EPA first assessed the status of the CBM industry as of 2008, i.e., the year for which the CBM survey collected detailed data. In light of the significant reduction in gas prices since 2008, EPA assessed which CBM projects operating in 2008 based on the CBM survey may have shut down since the time of the survey, or would potentially shut down, as a result of unfavorable economics in current conditions (baseline analysis). Following the baseline analysis, EPA analyzed the potential economic impact of additional controls on wastewater discharges on project economics (post-requirements analysis). EPA performed a similar analysis to assess current and future economic conditions for new CBM projects[1], and to evaluate whether new regulations would constitute a barrier to entry for new projects.

This document is organized as follows:

- *Section 1* provides a brief overview of the CBM industry
- *Section 2* describes the data sources and specific data items used in the economic analysis, the universe of analyzed existing and new projects, and wastewater management technologies considered
- *Section 3* discusses methodology and assumptions used to assess economic impact of wastewater management requirements on *existing* CBM sources.
- *Section 4* discusses methodology and assumptions used to assess economic impact of wastewater management requirements on *new* CBM sources.
- *Appendix A* describes how EPA developed projections of natural-gas prices used in the economic analysis.
- *References* lists data sources and other references used in EPA's economic analysis.

1 EPA defines a new source as a new CBM *project*, which can be as small as a single well or a lease with just a few wells, or as large as over 1,000 wells on multiple leases.

1 CBM Industry Overview

CBM is the natural gas contained in and removed from coal seams. Unconventional gas is natural gas trapped in underground rocks which is hard to reach and/or extract using conventional methods from the geological formation containing the gas. CBM extraction requires drilling wells into coal seams and removing formation water to reduce hydrostatic pressure and to allow adsorbed CBM to be released from the coal. The formation water removed from the coal seam is called produced water.

Typically, a CBM well will produce gas for between 5 and 15 years, although wells in some areas may have a longer lifespan. CBM wells go through the following production stages:

- An early stage, during which large volumes of formation water are pumped from the seam to reduce the underground pressure and encourage the release of natural gas from the coal seam;
- A stable stage, during which the amount of natural gas produced from the well increases as the amount of formation water pumped from the coal seam decreases; and
- A late stage, during which the amount of gas produced declines and the amount of formation water pumped from the coal seam remains low (De Bruin et al., 2001).

CBM operators typically plan and operate multiple-well projects, which are structured to achieve economically efficient recovery of the CBM gas, accounting for such considerations as the well-spacing that is needed to efficiently recover the resource in place. EPA defines a CBM *project* as a well, group of wells, lease, group of leases, or some other recognized unit that is operated as an economic unit when making production decisions. A project can be as small as a single well or a lease with just a few wells, or as large as over 1,000 wells on multiple leases. All wells in a project may not be drilled at the same time; therefore, a CBM project can have a longer lifespan than the longest-lived well in that project. EPA identified 15 CBM basins producing gas in 2008. *Section 3* of the *Technical Development Document* provides additional background on CBM production.

Table 1-1 summarizes the total gas production from CBM formations in the United States between 2007 and 2011, as published by the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE) (U.S. DOE, 2013a)0. As shown in *Table 1-1*, CBM gas production peaked in 2008 at just over 2 trillion cubic feet. This peak production year also coincides with the calendar year in which EPA collected information in the Detailed Questionnaire (see *Section 2.1.1*). *Table 1-1* also presents total production of shale gas, which is also unconventional gas. As shown in *Table 1-1*, while CBM production declined since 2008, production of shale gas increased significantly from 2007 to 2011.

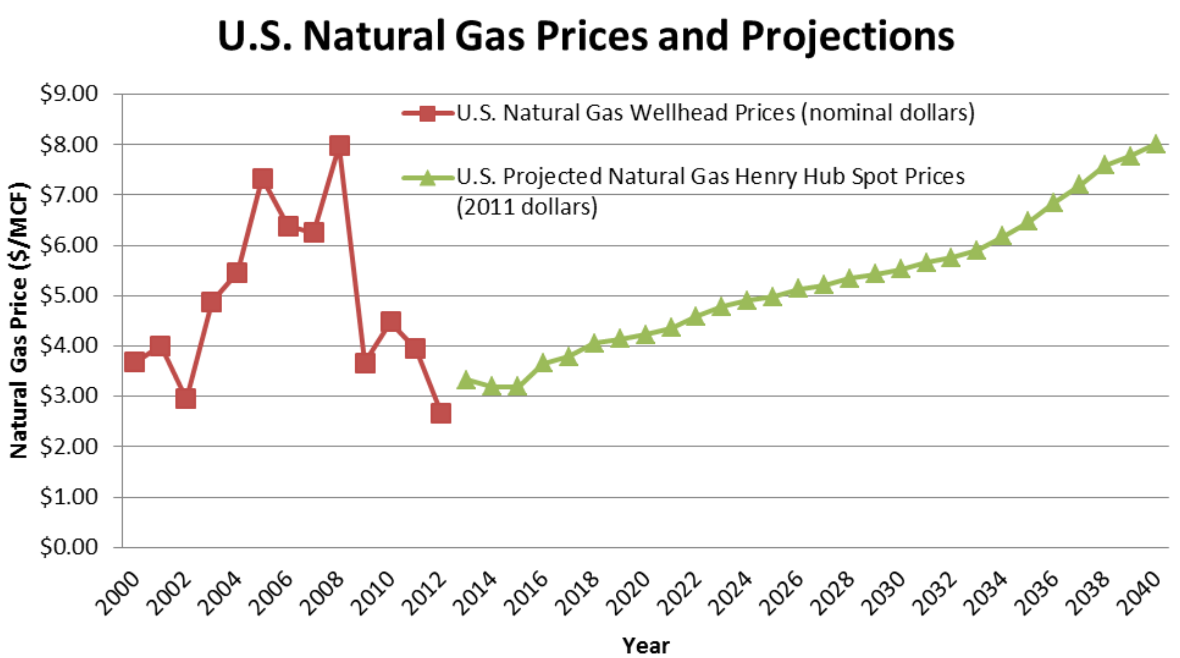
Table 1-1. Total CBM Gas Production (Million Cubic Feet), 2007–2011

Industry	2007	2008	2009	2010	2011[a]
Coalbed Methane Wells	1,999,748	2,022,228	2,010,171	1,916,762	1,779,055
Shale Gas Wells	1,990,145	2,869,960	3,958,315	5,817,122	8,500,983

a. Data for 2011 are estimated.
Source: U.S. DOE, 2013a

The substantial increase in gas production from shale formations coupled with a weak economy has led to significant declines in natural gas prices. *Figure 1-1* presents national average U.S. natural gas wellhead prices for 2000 through 2012, and EIA-projected prices through 2040. Gas prices generally vary by state. For example, Henry Hub, which is a major gas distribution hub and pricing point for gas futures in the United States, is located in Louisiana. The higher the transportation cost to Henry Hub, the lower the wellhead price received by the operators. Because transport costs from states located near Louisiana are much lower than those from the Rocky Mountain area, the average wellhead price for states such as Texas, Louisiana, and Alabama are higher than in the Montana or Wyoming. As shown in *Figure 1-1*, in 2008, average annual U.S. wellhead gas prices were at a historic high of $7.97 per Mcf. In 2009, the price of gas fell by 54 percent, to $3.67 per Mcf. While EIA projects that gas prices will rise steadily over the next few decades, EIA does not expect to prices to reach the 2008 price level (on an inflation-adjusted basis) until 2040.

Figure 1-1: U.S. Natural Gas Prices 2000 to 2012 and Projected Prices through 2040



Source: U.S. DOE red line (square)2013b and green line (triangle)2012b

Produced water (or wastewater) requires some form of management (e.g., use or disposal). CBM operators often combine produced water from multiple wells, and occasionally multiple projects, into a Produced Water Management System (PWMS). In some cases, operators transfer this wastewater to another operator's PWMS for management and disposal. CBM well operators use a variety of methods to manage, store, treat, and dispose of CBM produced water. *Section 4* of the *Technical Development Document* provides information on produced water management and treatment.

Generally, for purposes of this analysis, EPA classified wastewater management alternatives based on the type of wastewater discharge as follows:

- Discharge – Either direct discharge to surface water or indirect discharge to publicly-owned treatment works (POTW); or
- Zero discharge – Includes the following alternatives: underground injection, evaporation/infiltration ponds, land application (for crop or non-crop production), livestock or wildlife watering, or transferring the water off-site .

Generally, operators may manage the produced water from a single project by both discharge and zero-discharge methods, either applied separately or in combination for the same project.

As discussed in the *Technical Development Document*, EPA identified the following seven basins in which direct discharge is practiced by at least one project (discharging basins) out of the 15 CBM basins producing gas in 2008:

1. Appalachian;
2. Black Warrior;
3. Cahaba;
4. Green River;
5. Illinois;
6. Powder River; and
7. Raton.

The remaining eight basins use only zero-discharge methods for disposal. As a result, EPA focused the economic analyses on these seven discharging basins because ELGs would only lead to possible incremental costs for CBM projects that discharge some portion of their produced water. Even though the analysis focused only on the seven basins in which some projects are not zero-discharge, EPA views the analysis as nationally representative because the projects in the remaining basins already use one of the technologies analyzed and therefore would face no incremental cost. EPA expects changes to industry economics due to declining gas prices to have a similar effect on all CBM projects, both discharging projects and those that use zero-discharge methods for managing produced water (both in discharging basins and non-discharging basins). Drilling costs, gas production costs, and available produced water-management methods and costs vary by basin; therefore, the overall financial impact of reduced gas prices will also vary by basin. Because surface water discharge generally does not require transport of the produced water, it entails lower private costs of disposal than zero-discharge methods. Because of the generally higher costs for using zero-discharge methods for produced water discharge, EPA expects that declining gas prices will have a similar adverse effect on the economics of CBM projects that use zero-discharge methods for managing produced water (both in discharging basins and non-discharging basins), to the effect estimated for discharging projects.

2 Data Sources, Universe, and Wastewater Management Alternatives

This section describes the data sources and specific data items used in the economic analysis, the universe of analyzed existing and new projects, and wastewater management technologies considered.

2.1 Data Sources

EPA used information reported in the Detailed Questionnaire, supplemented with data from publicly available sources, to conduct the economic analysis for new and existing CBM projects. The following subsections provide a brief description of these data sources. Additional information can be found in the *Detailed Study Report* and *Technical Development Document*.

2.1.1 CBM Survey

In 2009, EPA distributed a Screener Questionnaire to all CBM operators that had three or more CBM wells with production in 2006. The Screener Questionnaire requested that operators provide the following information on all projects operating as of 2008: verification that the operator produced CBM in 2008; identification of small businesses and number of projects operated; and, for each project, information on numbers of wells, gas production, and produced water management methods.

Using information gathered through the Screener Questionnaire, EPA identified a representative sample of over 200 CBM projects across the country. EPA distributed a Detailed Questionnaire to this sample, requesting technical, financial, and economic data at the project level. The Detailed Questionnaire collected information for calendar year 2008 and represented a 'snapshot' of the industry during this one-year period. The one-year 2008 snapshot contains information for projects at various production stages.

EPA distributed the Detailed Questionnaire to all CBM projects that discharged except for some projects in the Powder River Basin. Because the Powder River Basin had several operators with a large number of projects, to reduce the burden on these operators, EPA selected a statistical sample of discharging projects. The memorandum *Development of Final Survey Weights for CBM Analyses* (DCN CBM00653) explains how EPA scaled the results of the project-level analysis to the industry level.

The majority of data reported in the Detailed Questionnaire were claimed Confidential Business Information (CBI). Of the 87 operators responding to the Detailed Questionnaire, approximately 70 percent claimed the entire response CBI and all operators claimed some portion of their response to be CBI. Therefore, EPA is not in a position to provide full data for individual projects, operators, or basins in public documents. The memorandum *Summary of Confidential Business Information Claims in the Industry Responses to EPA's Screener and Detailed Questionnaire and Data Available in the EPA Docket* (DCN CBM00661) provides information on the CBI claims and the information that can be released to the public.

2.1.2 Publicly Available Data

Due to changes in the industry since 2008, EPA supplemented the data collected in the Detailed Questionnaire with more current publicly available data. EPA reviewed the sources listed below to identify changes to gas prices and operating status of analyzed existing CBM projects.

- U.S. DOE's EIA – Information on projected natural gas production, wellhead prices, and other supplemental information (http://www.eia.gov/).

- State oil and gas websites – Gas and water production data used to evaluate changes in operating status, from the following States:
  - Colorado (Raton Basin)
  - Wyoming (Powder River and Green River Basins)
  - Pennsylvania (Appalachian Basin)
  - West Virginia (Appalachian Basin)
  - Alabama (Black Warrior and Cahaba Basins)
  - Montana (Powder River Basin)

2.2 Analyzed CBM Projects and their Baseline Characteristics

Because the Detailed Questionnaire collected information at the project level, EPA conducted technical and economic analyses at the level of a project. As detailed in *Chapters* 3 and 4 of this document, EPA's economic analysis for both existing and new projects, assesses the economic viability of a project over its estimated lifetime in the baseline and post-requirements scenarios. EPA used pre-tax operating income to assess the economic viability of a project. This section describes specific data items EPA used to calculate baseline pre-tax operating income for existing and new projects. It also describes the universe of existing and new CBM projects for which the Agency conducted economic analysis.

2.2.1 Existing Projects

As discussed in the *Technical Development Document*, EPA identified 73 existing direct-discharge projects based on the data received through the CBM survey for 2008[2]. These are sampled projects that reported directly discharging at least some portion of their produced water in 2008, but may also use other disposal methods. EPA used the Detailed Questionnaire responses along with discharge monitoring report data to determine the volume of produced water discharged. *Section 5.1.1* of the *Technical Development Document* and the memoranda *Supporting Information for Existing Source Analysis* (DCN CBM00664) provide additional information on identifying the direct-discharge projects, the produced water volume generated, and the produced water volume discharged directly to surface waters. As described in *Section 3*, EPA analyzed the 73 sampled projects and applied survey weights to scale the results to the entire CBM industry consisting of 148 direct-discharge projects. See *Development of Final Survey Weights for CBM Analyses* (DCN CBM00653).

EPA reviewed oil and gas websites for the states listed in *Section 2.1.2* to determine whether the operating status of any of these 73 direct-discharge projects had changed since 2008. Calendar year 2010 was the most recent year with complete data available at the time EPA conducted this review. EPA reviewed information on operators in the six basins with data (Appalachian, Black Warrior, Cahaba, Green River, Powder River, and Raton) to determine whether: (1) the operator was still producing CBM and (2) the operator was still producing water. EPA did not review information for operators in the Illinois Basin because the State of Illinois provides little information on oil and gas production. Based on this review, EPA determined that seven (13 on a weighted basis) of the 73 direct-discharge projects were no longer producing CBM or no longer producing water as of 2010. While these seven (13 on a weighted basis) projects are a part of the analyzed universe of existing CBM projects, EPA did not develop wastewater management costs for them, and treated them as baseline closures in the analysis (see *Section 3*). The memorandum *Changes to CBM Operating Status Between 2008 and 2010* (DCN CBM00715) provides additional details on EPA's review.

[2] As explained in the Technical Development Document, EPA identified 74 projects based on questionnaire responses and excluded one from further analysis.

As discussed in *Section 3*, EPA's existing-source analysis assesses the economic viability of existing CBM projects over their lifetime, accounting for projected changes in natural gas prices and other factors that influence project economics. EPA used 2008 as the base year for this analysis because 2008 is the base year for the CBM survey, and is therefore the year with the most detailed information about project economics. For each analyzed project, EPA calculated project revenue, earnings, gas production operating costs, and water management operating costs for the produced water management method for calendar year 2008 using data collected through the CBM survey. *Table 2-1* shows the Detailed Questionnaire data elements used to develop baseline financial project characteristics.

Table 2-1. Project Inputs Used in Existing Source Analysis

Project-Level Input	Detailed Questionnaire Data Elements Required	Detailed Questionnaire Question
Gross revenue - All money received in 2008 for the gas sold. Project gas production sold (Mcf) multiplied by the project average wellhead price ($/Mcf).	2008 gas sold	Question B3-60
	2008 average wellhead gas price	Question B3-62: Requested minimum, average, and maximum wellhead price received for the project.
Net Revenue – Gross revenue for gas sold minus royalties (mineral rights owner share of production revenue), severance taxes (state share of production revenue), and ad valorem taxes (local/county share of production revenue).	2008 royalty rate	Question B3-65
	2008 severance payment and severance tax percentage	Question B3-66
	2008 ad valorem payment and ad valorem tax percentage	Question B3-67
Gas production operating and maintenance (O&M) costs.	2008 total gas production O&M costs	Question B3-50
Produced water management O&M costs for current method – Includes revenue received by operator for treating produced water from another operator and all water transport costs.	2008 produced water management system (PWMS) O&M cost (2008 O&M cost for operating the PWMS)	Question C2-7a
	2008 total revenue from operating PWMS	Question C2-7b
	2008 transport O&M costs (O&M costs for gathering and transporting the produced water to the PWMS)	Question C2-8c
	2008 trucking O&M cost (O&M for transporting water by truck to the PWMS)	Question C2-8d(v)
As discussed in *Section 3.1.1*, to assess the cost impact of wastewater management and discharge options, EPA estimated project economics for years after 2008 to evaluate project economics over the lifetime of a project. To do that, EPA used the following data items from the Detailed Questionnaire in addition to data items above: 2008 amount of water produced (Question C2-3); 2008 discharged water (volume of produced water from PWMS to destination) (Question C3-2); and percentage of O&M costs that would have been incurred during a temporary shutdown of the project (Question B3-51).		

To assess project economics over the lifetime of a project, EPA also estimated typical gas and water decline rates for each discharging basin using information from the Detailed Questionnaire. Questions B3-98 and B3-99 of the Detailed Questionnaire requested projected gas (MMBtu/yr) and water (bbls/yr) production data for 2009 through 2013. While EPA received limited complete responses to these questions, EPA used this data to estimate gas and water declines over the five-year because it is the best available data. *Table 2-2* reports estimated gas and water decline rates for the eastern (IL, PA, VA, WY, AL) and western (WY, MT, CO) states. While EPA determined and used gas and water decline rates for each discharging basin, EPA reports here only the regional averages to protect CBI claims.

Further, because future project revenue depends on future gas prices, EPA developed gas-price projections to use in the economic analysis. *Appendix A* provides additional information on these projections. As described in *Section 3*, EPA applied the estimated basin-specific gas and water decline rates to the initial 2008 gas and water production, and used projected gas prices to estimate revenue over the lifetime of the CBM project.

Section 3 describes the existing-source analysis, including analysis methodology and findings.

Table 2-2: Estimated Average Annual Gas and Water Decline Rates		
Region	**Gas**	**Water**
Eastern U.S. basins	7.4%	6.5%
Western U.S. basins	11.2%	13.1%

2.2.2 New Projects

As detailed in *Section 4*, EPA's new-source analysis relies on model projects and assesses the economic viability of new projects, whether beginning at present or in future years, accounting for projected changes in natural gas prices and other factors that influence CBM development decisions. EPA assumed that, similar to existing CBM projects, new sources in the seven discharging basins would use surface discharge, and that new sources in zero-discharge basins would use zero-discharge approaches to manage produced water. EPA did not evaluate basins in which development activity began after 2012. EPA expects that development prospects in the undeveloped basins would be less favorable than those for basins with existing production, because of lower production potential, higher drilling costs, and/or lack of existing infrastructure to pipe gas to centralized gas transmission hubs. To the extent that the analysis finds challenges in new project development in the basins with existing production, EPA expects that these challenges would be at least as great in basins without current production. EPA therefore concluded that analysis of the basins with existing development provides an initial indication of the potential effect of new source regulations.

For the new-source analysis, EPA developed model projects specifically for five of seven discharging basins: Appalachian, Black Warrior, Green River, Powder River, and Raton. EPA did not have information to develop model projects for the Illinois basin. Because the Illinois basin has limited CBM development as of 2008, EPA expects future development in this basin will also be limited. For this analysis, EPA assumed the Illinois basin is similar to the Appalachian Basin, based on the basins being roughly contiguous, with similar geology, and with potentially similar cost structures and access to water management methods. In addition, EPA did not develop a separate model project for the Cahaba Basin, but assumed that the Cahaba Basin is similar to the Black Warrior Basin, again based on proximity, similarity of geology, and access to similar water management methods. These assumptions are based on best professional judgment. *Section 3.3* of the *Technical Development Document* provides details on coal basins with potential for CBM development.

A model project represents a typical new project(s) for the basin in terms of the profile of drilling, gas and wastewater production, and drilling and production costs. The model projects thus provide a basis for assessing how treatment technology requirements would affect project economics – in particular, whether treatment technology requirements could constitute a barrier to development[3] of projects that would otherwise be economically viable. Additional details on the development of model projects, including a discussion of the basins included in EPA's new-source analysis, are included in the memorandum *Supporting Information for New Source Model Projects* and the supporting CBI spreadsheet (DCN CBM00666 and CBM00666.A1).

EPA defined model projects using the input parameters listed in *Table 2-3* primarily based on information reported in the Detailed Questionnaire for existing projects. EPA developed one set of model projects (*primary* model projects, designated APP1, BW1, GR1, PRB1, and Raton1) using information received

[3] In analyses of effluent guidelines pertaining to industrial facilities, EPA uses the term *Barrier to Entry* in assessing the impact of new source requirements on the construction and operation of new facilities – i.e., entry of new facilities/discharge sources into the industry. This analysis, which focuses on new project/source development, is based on the same economic impact concept, except that the terminology *Barrier to Development* better reflects the considerations of a CBM operator in evaluating whether to develop a new project opportunity.

through the Detailed Questionnaire only. EPA developed *secondary* models for three basins − the Appalachian (APP2), Black Warrior (BW2) and Powder River (PRB2) – using publicly available data supplemented with Detailed Questionnaire data.

For the primary model projects, EPA calculated the average value for each input parameter for each basin using information available in the Detailed Questionnaire. The input parameter values vary by basin due to variations in basin geology and proximity to gas infrastructure. EPA compiled input parameter averages from EIA and publicly available SEC filings to develop the secondary model project for comparison to the parameter values obtained from the Detailed Questionnaire. If information was not available from public data sources for the basin, EPA used the Detailed Questionnaire average to supplement the secondary model project scenario. *Table 2-3* shows the range of input parameter values used in the new projects analysis. EPA used basin-specific values for each model project in the new-source analysis; however, because survey respondents claimed most data collected in the Detailed Questionnaire as CBI, EPA does not report here the basin-specific values, which were derived from data claimed as CBI. The values presented in *Table 2-3* represent the ranges across all five basins for both the primary and secondary model project scenarios. *Table 2-3* also lists the Detailed Questionnaire question number, with field name noted parenthetically, that underlie the primary model project data items. The *Supporting Information for New Source Model Projects* (DCN CBM00666) provides additional information on the development of the model project assumptions.

EPA used the model project characteristics along with the gas and water decline rates described in *Section 2.2.1*and the gas price projections described in *Appendix A* to analyze the potential effects of wastewater management technology costs on new sources. *Section 4* describes the new-source analysis, including analysis methodology and findings.

Table 2-3. Model Project Characteristics[a]

Input Parameter	Range of Values	*Primary* Model Project – Detailed Questionnaire Question	*Secondary* Model Project
Wells per project (# wells)	48-400	CBM Survey Question A-1 (wells in project) and Screener data	
Initial gas production (MCF/day/well)	33-112	CBM Survey Question B-59 (total gas)	U.S. DOE, 2010; U.S. DOE, 2002; Vail and Conrad, 2003
Initial water production (bbl/day/well)	13-600	CBM Survey Question B-63 (total water)	U.S. DOE, 2010; Petroleum Association of WY, 2005
Land cost ($/well)	$380-$200,000	CBM Survey Questions B-20 (lease acquisition sum) and B-22 (lump sum to secure lease)	U.S. DOE, 2002; Ladlee, 2011; Lewis, 2004
Drilling cost ($/well)	$58,000-$853,000	CBM Survey Questions B-47 (total cost of well drilling) and B-48 (total number of wells drilled)	U.S. DOE, 2002; SEC filings
Lease cost ($/well)	$7,830-$164,000	CBM Survey Questions B-23 (one-time outlays for project development, before 2008) and B-49 (total outlay on project development, 2008)	U.S. DOE, 2010
Gas production operating cost ($/MCF)	$0.41-$1.99	CBM Survey Questions B-50 (total O&M costs for gas production - 2008) and B-59 (total gas)	U.S. DOE, 2010; U.S. DOE, 2002
Water production operating cost ($/bbl of produced water)	$0.00-$0.45	CBM Survey Questions C2-7 (total O&M costs for water management - 2008) and C2-3 (total water managed)	U.S. DOE, 2002
Fixed gas production cost[b] ($/well)	$978-$17,400	Assumed 5 percent of total gas production operating cost	U.S. DOE, 2010
Fixed water management operating cost ($/well)	$0-$356	Assumed 5 percent of total water production operating cost	

a. Dollar values were converted to 2010 dollars using a GDP adjustment.
b. Fixed water management cost is included in fixed gas production cost reported in U.S. DOE 2010.

2.3 Wastewater Management Technologies Considered

The Clean Water Act provides for development of different levels of pollutant control for existing and new sources, and specifies the factors to be considered in developing those levels of control.[4] Therefore, EPA analyzed the impact of potential wastewater discharge requirements on existing sources and new sources separately.

Under both the existing- and new-source analyses, EPA looked at economic viability of a given project without any new discharge requirements (baseline analysis) and with new discharge requirements (post requirements). For this analysis, EPA did not identify and formally select technology options for consideration. Rather, EPA included two technology options for consideration: one that would be the basis for numerical discharge limitations (ion exchange, abbreviated as IX) and one that would be the basis of zero-discharge limitations (underground injection or UI). EPA based costs for ion exchange on the ion exchange system used by operators in the Powder River Basin, and publicly available ion exchange cost data. As explained in the *Technical Development Document*, this system may not be appropriate for TDS levels in CBM produced water in all basins evaluated. Nevertheless, EPA applied the ion exchange costs to projects in all basins to determine whether the projects are economically capable of implementing a technology with a similar or higher cost than ion exchange (e.g., reverse osmosis).EPA evaluated UI because it eliminates all discharges to surface water and is currently used for CBM produced wastewater disposal in the majority of basins. *Table 2-4* presents the IX costs for TDS removal prior to surface discharge and UI costs to eliminate the discharge of produced water. Note, unlike many industries that EPA has analyzed for development of effluent limitation guidelines, the CBM industry is different in that EPA expects that wastewater management technology and associated costs will be the same for both existing and new projects. This is due to the nature of the technologies and how they are applied to a project, regardless of whether the project is existing or new. For details on IX treatment and UI disposal methods, see Section 4 of the *Technical Development Document*.

Table 2-4. Wastewater Management Costs

Water Management Method	Region	Costs ($/barrel of produced water)
Ion Exchange	All basins	$0.50
Underground Injection	Eastern U.S. basins	$4.10
	Western U.S. basins	$0.54

4 See EPA's Effluent Limitations Guidelines website for additional information (http://water.epa.gov/scitech/wastetech/guide/index.cfm).

3 Economic Analysis - Existing Sources

As described earlier, because the Detailed Questionnaire requested data at the project level, EPA conducted economic analysis at the level of the project. Specifically, EPA assessed the impact of the costs associated with potential wastewater discharge requirements on economic viability of analyzed existing CBM projects in two steps:

- First, EPA assessed which projects may have closed due to deteriorating project economics (in particular, because of declining gas prices) since the time of the survey, or that would potentially close under current conditions (baseline analysis).
- Second, EPA assessed the impact of wastewater discharge requirements – based on IX and UI – on projects that were found viable in the baseline analysis (post-requirements analysis).

The Agency conducted this analysis looking at project performance and economics over each project's potential production life, based on estimated changes over time in production levels, project costs, and natural gas prices. This is called a net present value approach. Companies use net-present value analysis to understand how much value an investment or project adds to the firm. The analysis discounts future revenue and costs over the production life of a project back to the present. Accounting for future natural gas prices is important in assessing project economic performance, given that natural gas prices, while recently in a down-trend, are expected to increase over the next several decades. Projects that appear to have unfavorable economics in the near term may look economically viable when viewed over a longer time horizon because of expected increases in gas prices. The analysis uses the 2008 data reported in the CBM survey as the starting point and estimates project economics over a 35-year period beginning in 2008. EPA used a 35-year production period in order to capture the potential CBM production period for a project. Wells typically have a shorter life than 35 years, but projects may have a longer life because they could have multiple wells that may not be drilled all at once.

To account for year-over-year changes in project economics, EPA relied on various assumptions about changes in gas and water production levels, production costs, and natural gas prices. These assumptions are inherently subject to uncertainty; nevertheless, EPA believes that this analysis provides important insight into the potential impact of CBM wastewater treatment or disposal requirements.

EPA's assessment of economic impact focused on the following questions:

- *Baseline analysis*: Under current conditions without national limits for unconventional oil and gas, will continued production from an existing CBM project be economically viable, given estimated future CBM gas production, natural gas wellhead prices, and production costs?
- *Post-requirements analysis*: For projects assessed as economically viable in the baseline, would they remain viable considering the change in project economics in the face of wastewater discharge requirements – looking over the potential life of the project? Would wastewater discharge requirements reduce the project's life (including the possibility that the project would be immediately uneconomical), compared to the baseline? If so, by how many years, and with what change in total CBM gas production?

EPA also conducted a static single-year analysis of economic viability assessing project economics in 2008 based only on the data reported in the CBM survey. The single-year analysis involved fewer assumptions about future production, costs, and prices than the multiple-year, projection-based analysis, but does not account for expected increases in natural gas prices. Accordingly, EPA judges this single-year analysis not to be as analytically sound as the multiple-year, projection-based analysis. Nevertheless, the findings from the single-year analysis are consistent with those generated using the multiple-year, projection-based analysis discussed in this document.

Table 2-1 in *Section 2.2.1* provides information on the CBM survey data items used in this analysis.

3.1 Baseline Closure Analysis

3.1.1 Analysis Approach and Data Inputs

This step assesses the baseline economics of existing projects and identifies those projects that are either:

- Not economically viable before consideration of the wastewater discharge requirements, when viewed over their potential production life. These projects are *immediate baseline closures*; EPA removed these projects from the subsequent post-requirements analysis.
- Economically viable before consideration of the wastewater discharge requirements, when viewed over their potential production life. EPA retained these projects in the subsequent post-requirements analysis.

As discussed in *Section 2.2.1* EPA conducted this analysis for 148 direct-discharge projects (on a weighted basis) across seven discharging basins – Appalachian, Black Warrior, Cahaba, Green River, Illinois, Powder, and Raton – using 2008 as the base analysis year.[5] As described earlier in this document, because 2008 is the base year for the CBM survey, 2008 is the analysis year with the most detailed information about project economics. EPA used pre-tax operating income (net revenue less operating costs, as defined below) as the financial measure to assess CBM project economics.[6]

As described above, this analysis accounts for future gas-extraction and water-production profiles, expected changes in wellhead natural gas prices, and resulting changes in project economics. Increasing gas prices, along with a changing profile in gas and water production over time, could change project economics from that indicated by a single-year analysis, especially one based on a low point in the market.[7]

EPA based this analysis on the project's pre-tax cash flow and maximization of the discounted net present value (NPV) of cash flow, using required rates of return (hurdle rates) as described below. EPA assessed projects with negative pre-tax operating income as *immediate baseline closures*, and excluded these projects from the post-requirements analysis. EPA assessed projects with positive 2008 pre-tax operating income as *baseline passes* and carried them forward for the post-requirements analysis (*Section 3.2*).

As discussed in *Section 2.2.1*, EPA found that of the 148 direct-discharge projects, 13 were no longer operating as of 2010. EPA decided keep these 13 projects in the analyzed universe of existing projects, because they responded to the CBM questionnaire as being in production at 2008, but to treat them as immediate baseline closures independent of any analysis. For the remaining 135 projects, EPA first calculated 2008 operating income, using data provided in the CBM survey and described in *Section 2.2.1*, by subtracting *operating costs* from *net revenue*, which EPA estimated as follows:

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5 For details on development of weights, see memorandum "Development of Final Survey Weights for CBM Analyses" (DCN CBM00653).

6 *Pre-tax* refers to income taxes – i.e., taxes that are paid on the basis of the project's pre-tax income. Subsequent discussion refers to certain *non*-income taxes – severance tax and *ad valorem* tax – which are paid on the basis of the gross value of gas production. This analysis *does account* for these non-income tax items, which are part of the calculation of pre-tax operating income/cash flow.

7 In particular, if water production, and thus related treatment costs, decline more rapidly than CBM gas production.

- *Net revenue*: To calculate net revenue, EPA first calculated gross revenue as the product of gas sold and average wellhead gas price. EPA then calculated net revenue by subtracting 'off-the-top' production payments – royalty payment, severance tax, and ad valorem tax – from gross revenue. EPA used severance tax and ad valorem payments as they are reported in the CBM survey, and calculated royalty payments as the product of (1) gas produced, (2) average wellhead gas price, and (3) royalty rate.
- *Operating costs*: The Agency calculated operating costs as the sum of total gas production O&M costs and total Produced Water Management System (PWMS) O&M costs. EPA calculated PWMS O&M costs as the sum of costs for (1) operating the PWMS, and (2) gathering and transporting produced water from CBM wells to the PWMS, *less* revenue, if any, from processing produced water from other projects, for a fee.

EPA then developed an operating cash-flow profile, by year, for each analyzed project, based on (1) quantity of CBM gas produced and sold by the project, (2) water produced, (3) project net revenue, accounting for reductions from gross revenue and changes in gas wellhead prices, and (4) operating costs. EPA calculated the NPV of future cash flows over all potential durations of the project. For example, if the project has the technical potential to continue production for 20 years beyond 2008, EPA calculated the NPV for each duration from the first year (2009) through 20 years (2028). EPA then identified the year in which NPV is maximized, and determined whether the *maximum NPV* is positive. If the project would not achieve a positive NPV over any of these durations, EPA assumed that the project would shut down in the first analysis year, i.e., 2008, and assessed the project as an *immediate baseline closure*.[8] If the project's maximum NPV is positive, EPA assessed the project as a *baseline pass*, and recorded the year in which maximum NPV is achieved (assumed to be the last year of production) and the quantity of CBM gas produced through that year. EPA later used these values to measure the impact of wastewater discharge requirements in terms of lost production years and gas produced. EPA carried these projects forward to the post-requirements analysis (*Section 3.2*).

EPA conducted this analysis as follows:

- *Defining analysis timeframe*: Because the CBM survey provided only limited data on projects' remaining production life,[9] EPA analyzed potential gas and water production over a uniform 35-year time period beginning in 2008, regardless of the age of the project.
- *Projecting gas production (Mcf)*: To estimate gas produced in each year following 2008, EPA developed and used gas-production decline rates by basin. *Table 2-2* shows the eastern and western U.S. average gas and water decline data. As described in *Section 2.2.1*, EPA provides

8 This analysis does not account for the previous outlays incurred by a project – e.g., project acquisition costs, development costs – and, in particular, doesn't ask whether the project is meeting the target rate of return on which the developer may have based the decision to undertake the CBM gas project. For this analysis, the Agency treated those costs as 'sunk' and examined only whether the project appears economically attractive on a current and forward-looking basis. Previous outlays could influence the forward-looking analysis because of the tax treatment of those outlays (e.g., depletion and depreciation); however, to capture these effects would require performing the analysis on an after-tax basis. EPA assessed an after-tax analysis as being not possible in the short-term, as this analysis would require additional data that would be very difficult or even impossible to obtain, and/or assumptions that would be very difficult to develop and defend. Moreover, EPA was not confident that the analysis would yield substantially different results if performed on an after-tax basis.

9 The CBM survey asked respondents to report remaining production life of a given project at 2008; however, of the 66 projects, only 19 projects (29 percent) provided this information.

only the regional averages to protect the CBI claims, although average decline rates were calculated for each of the five basins analyzed in the model.[10]

- *Projecting gas sales (Mcf)*: To estimate the amount of gas sold for years after 2008, EPA assumed that projects will sell the same percentage of total gas produced,[11] as indicated in the CBM survey for 2008 (calculated as gas sold/gas produced), and multiplied this percentage by total estimated gas production for each year.
- *Projecting amount of produced water (bbl)*: Similar to the gas production analysis, to estimate the amount of produced water after 2008, EPA developed and used an average water production decline rate by basin (see *Section 2.2.1*).
- *Projecting amount of produced water discharged from PWMS to surface water (bbl)*: To estimate the amount of produced water that is discharged from PWMS to surface water (discharged water) after 2008, EPA assumed that projects will discharge the same percentage of total water produced based as reported in the CBM survey for 2008 (calculated as water discharged/water produced).[12,13] EPA multiplied this percentage by total estimated water production for each year.[14]
- *Projecting natural gas wellhead prices*: To estimate gas wellhead prices after 2008, EPA applied year-over-year percentage changes in wellhead prices (see *Table A.2-1* in *Appendix A*) to the average gas wellhead price reported in the CBM survey for 2008 (see discussion in *Section 2.1.1* and *Table 2-1*). EPA developed year-over-year percentage changes from gas-price projections in the *Annual Energy Outlook* (AEO) published by EIA. To reflect the uncertainty in price projections, EPA considered three price growth cases in this analysis: reference case, high price growth case, and low price growth case (for details see *Appendix A*).
- *Projecting operating income*: EPA calculated operating income for each year after 2008 by subtracting operating costs from net revenue estimated as follows:
  - *Projecting net revenue*: EPA estimated net revenue for each year following 2008 as gross revenue less 'off the top' production payments – royalty payments, severance tax, and ad valorem tax – estimated for a given year. The Agency estimated these components on an annual basis as follows:
    - *Gross revenue*: EPA calculated gross revenue as the product of (1) gas sold and (2) wellhead gas price estimated for each year following 2008.

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10 EPA also tried to estimate project-specific decline rates using information on remaining technically recoverable reserves or, if not available, remaining proved reserves, and the project life for technically recoverable reserves, all from the CBM survey. However, information on project life was only available for 19 projects (29 percent of all projects). Further, EPA observed a possible inconsistency between the units in which technically recoverable reserves and remaining proved reserves were reported for some projects, and thus decided against using this approach.

11 Some gas may be used onsite.

12 Before using the volume of produced water discharged from PWMS to surface water reported in the CBM survey in these calculations, EPA adjusted the reported values to account for any transfers between projects. For details see memorandum "Supporting Information for Existing Source Analysis" (DCN CBM00664).

13 EPA recognizes the uncertainty in this assumption, but lacks information to support a different assumption.

14 The total water produced may exceed the water discharged to surface water because projects may use multiple disposal methods (e.g., surface discharge and livestock watering). The wastewater-treatment technology would only affect the portion of water discharged to surface waters.

- *Royalty payment*: EPA calculated royalty payment as the product of (1) the royalty rate reported in the CBM survey,[15] (2) estimated year-specific wellhead gas price, and (3) estimated year-specific gas produced.
- *Severance tax*: For the 38 unweighted projects (58 percent of the analyzed 66 projects) for which the CBM survey reports severance tax rate, EPA used the reported rate. For the remaining 28 unweighted projects, the Agency estimated the severance tax rate by dividing severance tax payment by gross revenue, both of which are reported in the CBM survey for 2008. The Agency calculated severance tax payments for years after 2008 as a product of (1) the reported/estimated severance tax rate and (2) gross revenue.
- *Ad valorem tax*: For the 38 unweighted projects (58 percent) for which the CBM survey reports ad valorem tax rate, EPA used the reported rate. For the remaining 28 unweighted projects, the Agency calculated ad valorem tax rate by dividing the ad valorem tax payment by revenue, both of which are reported in the CBM survey for 2008. The Agency calculated ad valorem payment for years after 2008 as the product of (1) reported/estimated ad valorem tax rate and (2) gross revenue.

- *Projecting operating costs*: EPA estimated operating costs on an annual basis as follows:[16]
  - *Produced Water Management System (PWMS) O&M costs*: For this analysis, EPA assumed that PWMS O&M costs include no fixed component; consequently, all PWMS O&M costs are assumed to vary linearly with the amount of produced water.[17] To estimate total PWMS O&M costs after 2008, EPA assumed that unit O&M cost per bbl is constant and calculated this unit cost using 2008 values. The Agency multiplied this unit cost by the amount of produced water.
  - *Gas production O&M*: Gas production O&M costs consist of fixed and variable O&M costs. Fixed O&M costs do not vary with the amount of gas produced. To calculate the fixed cost value, the Agency multiplied (1) the fixed O&M cost percentage[18] by (2) 2008 total gas production O&M costs.[19] EPA assumed that fixed O&M cost would remain constant in subsequent years. EPA subtracted this fixed cost value from reported total gas production O&M to calculate the variable O&M cost in 2008. To estimate variable gas production O&M costs in subsequent years, EPA assumed that unit variable O&M cost per Mcf is constant over time; EPA calculated this unit cost by dividing estimated 2008 variable gas production O&M costs by the amount of gas produced in 2008. To estimate variable gas production O&M costs for years, the Agency multiplied this unit cost by the estimated gas production quantity.

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15 EPA assumed the royalty rate to be constant over the project live, which is usually true.

16 EPA assumed no change, on an inflation-adjusted, constant dollar basis, in operating cost values over time. While it is possible that gas production and PWMS management costs will increase, it is equally possible that improvement in gas-extraction and water-management technology will lower those costs, again after adjusting for general inflation. Because EPA had no basis for estimating the direction or magnitude of these changes, the Agency assumed that these costs would remain constant on an inflation-adjusted basis.

17 To the extent that PWMS O&M costs include a fixed component, the PWMS O&M costs estimated after 2008 would be underestimated.

18 The share of O&M costs that would continue during a temporary shutdown of the project, as reported in the CBM survey.

19 For one project, percentage of 2008 fixed O&M costs is not reported; consequently, for this project EPA used average percentage estimated for the basin where this project is located, based on percentages reported for other projects in that basin.

- *Project profitability*: For calculating a project's NPV, EPA tallied project cash flows on a year-by-year basis as described above, on an as-incurred basis, with production continuing for as long as 35 years. EPA assumed that project developers produce gas until the year of maximum NPV and that this is the last year of gas production.[20] The Agency assumed that a project will shut down immediately if NPV is negative over all possible production life periods. To calculate NPV, EPA used 17-percent and 7-percent as target rates of return (or hurdle rates).[21] Target rates of return generally vary by project stage and are generally higher during project development. Risks such as resource and technical risk, or price and cost risks are greater, before the operator knows production per well, how many wells will be drilled, production costs, and resource/water mix, etc. However, as projects progress through development and production, target rates typically decline to reflect greater certainty of resource recovery and project economics. Because (1) the analyzed CBM projects are at varying stages of development and (2) the survey responses did not provide information on development stage, EPA did not assign stage-specific rates for analyzing individual projects. Instead, EPA used a range of rates – 17 percent and 7 percent – to bracket project economics, on both a baseline and post-requirements basis. The 17-percent rate is the midpoint of a range (12-22 percent) that EPA presented in the CBM survey questionnaire as possible rates of return sought by CBM project developers. Some survey respondents agreed that this range reasonably reflects rates of return sought by CBM project developers. Also, EPA received communications from developers suggesting that 17 percent is a reasonable estimate of the inflation-adjusted rate of return that developers seek to achieve in committing financial resources to undertake CBM projects. The 7-percent rate reflects the long-term opportunity cost of capital to U.S. industry, in real or constant dollar terms, as documented by the Office of Management and Budget in Circular A-4.[22] To the extent that the 17-percent target rate of return is more indicative of earlier stages of project development, it provides a higher range value for required return on investment. The 7-percent rate would be more indicative of the lower resource and economic uncertainty during a project's later production years, and provides a lower range value for required return on investment for use in the project NPV calculations.

3.1.2 Baseline Analysis Results

From the analysis outlined above, EPA found that 23 of the 135 analyzed projects would close immediately, (i.e., in the first analysis year, 2008) in the baseline regardless of the gas-price case or required rate of return used.[23] Together with the 13 projects that were non-operational as of 2010

[20] Generally, at this point, the project will have achieved its maximum NPV and subsequent production will generate negative cash flows and declining NPV. However, future gas price increases, coupled with changes in water production relative to changes in gas production, following the maximum-NPV year, may cause operating income to increase and become positive in future years. It is possible that if these projects continued to produce natural gas beyond the last year of the analysis period, their NPV would be maximized later, in a year after the end of the analysis period, in which case these projects would likely "operate" during the entire analysis period. It is also possible that prices will rise more slowly than projected, in which case, projects would shut down sooner than the maximum-NPV year estimated here. The estimates here reflect EPA's best information.

[21] *Hurdle rate* is the minimum rate of return on a project or investment required by an operator/investor.

[22] The difference between 17-percent and 7-percent would also reflect differences in the risk characteristics specific to the CBM project (geotechnical and economic/financial risks) as compared to the risks associated with overall economic activity in the U.S. economy. The difference could also reflect the business characteristics of the enterprises engaged in CBM gas development – for example, if the enterprises tend to be smaller and of lower investment grade than the profile of businesses in the general economy.

[23] As stated above, EPA also performed this analysis for 2008 only, using data reported in the CBM survey and found the same 23 projects as baseline closures. The finding of no difference in immediate closure results and potential project life based only on the single year of 2008 may be interpreted as follows: When a project is not viable in the first analysis year (i.e.,

according to State oil and gas websites, baseline closure projects represent 25 percent of total weighted project counts. For the remaining 112 projects – i.e., *baseline pass* projects – EPA recorded the year in which maximum NPV is achieved (assumed to be the last year of production) and the quantity of CBM produced through that year. EPA carried these projects forward to the post-requirements analysis (*Section 3.2*).

Further, looking beyond the baseline year, from the analysis outlined above, EPA also found that an additional 43 percent of projects would remain operating after 2008 but are likely to have shut down by 2012, based on the decline in natural gas prices and other estimated project changes since 2008. However, as stated above, because EPA assessed these projects as baseline passes relative to the 2008 analysis year, EPA kept these projects in the post-requirements analysis. EPA kept these projects in the analysis to test whether the CBM wastewater discharge requirements would cause the projects to close earlier than the year estimated in the baseline analysis and thus lead to losses in natural gas production.

3.2 Post-Requirements Analysis

3.2.1 Analysis Approach and Data Inputs

To analyze the impact of CBM wastewater discharge requirements on projects that are economically viable in the baseline (2008), EPA conducted the post-requirements analysis for the remaining 112 projects using the same methodology as described in *Section 3.1*.

For this analysis, EPA adjusted the profile of future cash flows to account for year-over-year estimates of IX and UI costs. EPA then recalculated the NPV of project cash flows over the potential project durations to determine the maximum NPV, and whether the maximum NPV value is positive. If the project would not achieve a positive NPV over any of these durations, EPA assumed this project would close immediately in 2008, the first year analyzed, and recorded this project as an *immediate post-requirements closure*. For projects with a maximum NPV that is positive (post-requirements pass), EPA recorded the maximum-NPV year, and the total production of CBM gas through that year. Specifically, for each of the *post-requirements pass* projects, the Agency compared the maximum-NPV year in the post-requirements analysis to the maximum-NPV year in the baseline analysis and assessed whether a given project would stop gas production earlier. An earlier shut-down of a project as the result of wastewater discharge requirements would result in a smaller amount of CBM gas produced.

EPA calculated IX treatment and UI disposal costs for years after 2008 based on the amount of discharged water estimated for those years. The Agency then subtracted the resulting treatment costs from baseline operating income.

As key output metrics for this analysis, EPA calculated (1) the change in total CBM gas production between baseline and post-requirements cases, (2) the change in the number of project-years, and (3) average number of production years lost per affected project.[24,25]

2008), the financial benefit of higher gas prices later in the analysis period coupled with declining costs for water management (relative to gas production) *does not* improve project economics sufficiently to support future production. The long-term viability of these projects is further undermined by large drops in gas prices during the earlier years of the analysis period (55 percent in 2009 and 38 percent in 2012). In general, water production declines more rapidly than gas production, leading to lower water management costs per unit of gas produced over the life of the project. For year-over-year changes in gas prices during the analysis period, see *Appendix A*.

[24] Project-years represent the sum of lost years of gas production across all projects.

[25] As is the case in the pre-requirements analysis, some projects return to positive operating income in years after the maximum NPV year, and operating income remains positive through the analysis period. However, even though NPV

3.2.2 Post-Requirements Analysis Results

Immediate Project Closures

EPA found the same number of projects to be immediate post-requirements closures, regardless of the gas-price case or required rate of return used in the analysis. This finding means that when projects are so substantially affected by the addition of CBM wastewater discharge requirements that they *might* shut down immediately, that changes in gas prices or the required rate of return, *within the ranges used in this analysis*, are not able to offset the substantial adverse impact of discharge requirements on project economics. Under the IX treatment requirement, 27 projects (24 percent) shut down. As reported in *Table 3-1*, EPA estimates that immediate termination of these projects would result in relatively small losses of project-years (average of two to three years per project) and natural gas production (less than 1 percent of baseline). The burden from additional treatment technology costs causes only a small reduction in project life or gas production for those projects that are found to terminate immediately. Given the relatively small losses in production years and gas quantity, this means that these projects would have shut down shortly after 2008 *regardless* of treatment technology costs – based on their baseline financial situation.

Generally, the impacts of requirements based on UI disposal, which is more expensive than requirements based on IX treatment, are greater than those estimated for IX treatment. Thirty projects (27 percent) shut down immediately. Similar to the finding for the IX treatment analysis, EPA estimates that immediate termination of these projects would result in relatively small losses of project-years (average of two to three years per project), and natural gas (less than 1 percent of baseline). Again, these findings mean that these projects would shut down soon after 2008, regardless of wastewater treatment or disposal costs.

In the same way as found in the analysis of immediate project-closures in the baseline (*Section 3.1.2*), the findings for immediate closures are the same for both the multiple year analysis approach, presented here, and the alternative single-year analysis, which EPA also performed. Again, this means that when a project is already not economically viable in the first analysis year, the financial benefit from higher gas prices *later* in the analysis period and improved project economics due to lower water production management costs are not sufficient to support future production.

Production Years Lost at Remaining Projects

With IX treatment, EPA estimates that some of the 85 post-requirements pass projects would stop gas production earlier than they would have absent the IX treatment (see *Table 3-1*). The gas losses due to shorter project life are larger than those estimated for the immediate project closures. At the 17-percent required rate of return, EPA estimates that 29 to 37 projects would shut down earlier than they would have in the baseline, depending on the gas-price case; these projects represent 26 to 33 percent of all baseline pass projects. On average, EPA estimates that each of these projects would lose 10 to 11 years of gas production relative to the baseline estimates of production life, resulting in a total gas loss of between 205 and 376 million Mcf (between 4 percent and 8 percent of the total baseline gas quantity). The losses in project-years and production are greatest under the low price growth case, and smallest under the high price growth case, with the estimates for the reference case falling in between. The estimated losses increase in moving from the higher to lower price cases because the lower price cases leave less operating margin for absorbing treatment technology costs, and thus greater potential for adverse impact.

With UI disposal, some of the remaining 82 projects that EPA did not assess as immediate post-requirements closures also stop production earlier due to disposal requirements. The total gas losses from

increases in those years, it never exceeds the maximum NPV achieved in the earlier year. These projects *might* reach a higher NPV, and continue production, if production were possible and analyzed beyond the last year of the analysis period.

shorter production lives of these projects are larger than the losses estimated for the IX treatment. At the 17-percent required rate of return, EPA estimates that between 44 and 49 projects would shut down earlier than in the baseline, depending on the gas-price case; these projects represent 39 to 44 percent of all baseline pass projects. Each of these projects would lose, on average, between 15 and 17 years of gas production, resulting in a total gas loss of between 1,691 and 1,853 million Mcf (between 34 percent and 38 percent of baseline gas quantity). As with the IX treatment technology, losses in project-years and gas production increase in moving from the high price growth, to reference, and low price growth cases.

For both the IX and UI, the impact findings vary less between the 7-percent and 17-percent required rate of return cases than across the gas-price cases. Where the impact results differ more than minimally, the losses are generally higher under the 17-percent rate than under the 7-percent rate. This finding indicates that IX treatment or UI disposal is likely to have a similar adverse effect on existing CBM projects regardless of their development stage and associated required rate of return on investment.

Table 3-1: Production-Years and Natural Gas Production Foregone due to Wastewater Discharge Requirements in Immediate Project Closures and in Projects that Remain in Production[a,b,c,d]

Analysis Case and Impact Metric	Technology Basis: Ion Exchange (IX)								Technology Basis: Underground Injection (UI)							
	Using 17 Percent Hurdle Rate				Using 7 Percent Hurdle Rate				Using 17 Percent Hurdle Rate				Using 7 Percent Hurdle Rate			
	Unweighted		Weighted		Unweighted		Weighted		Unweighted		Weighted		Unweighted		Weighted	
	Value	% of Total	Value	% of Total	Value	% of Total	Value	% of Total	Value	% of Total	Value	% of Total	Value	% of Total	Value	% of Total
High Price Growth Case																
Due to Immediate Project Closures[e]																
Gas Quantity	2.6	0.1%	8.8	0.2%	2.6	0.1%	8.8	0.2%	18.7	0.4%	25.5	0.5%	18.7	0.4%	25.5	0.5%
Project-Years	7	0.6%	89	5.4%	7	0.6%	89	5.4%	11	0.9%	94	5.7%	11	0.9%	94	5.7%
# of Projects	4	6.8%	27	24.3%	4	6.8%	27	24.3%	6	10.2%	30	26.9%	6	10.2%	30	26.9%
Years/Project	2	8.7%	3	22.3%	2	8.7%	3	22.3%	2	9.1%	3	21.2%	2	9.1%	3	21.2%
Due to Production Years Lost at Remaining Projects																
Gas Quantity	155.0	3.4%	204.8	4.2%	84.4	1.9%	111.1	2.3%	1,565.7	34.5%	1,691.2	34.4%	1,454.6	32.1%	1,539.5	31.3%
Project-Years	185	15.6%	298	18.1%	127	10.7%	184	11.2%	560	47.3%	730	44.3%	462	39.0%	595	36.2%
# of Projects	18	30.5%	29	26.2%	18	30.5%	29	26.2%	31	52.5%	44	39.3%	30	50.8%	43	38.4%
Years/Project	10	51.2%	10	69.1%	7	35.2%	6	42.7%	18	90.0%	17	112.9%	15	76.7%	14	94.2%
Reference Case																
Due to Immediate Project Closures[e]																
Gas Quantity	2.6	0.1%	8.8	0.2%	2.6	0.1%	8.8	0.2%	18.7	0.4%	25.5	0.5%	18.7	0.4%	25.5	0.5%
Project-Years	7	0.6%	89	5.5%	7	0.6%	89	5.5%	11	0.9%	94	5.9%	11	0.9%	94	5.9%
# of Projects	4	6.8%	27	24.3%	4	6.8%	27	24.3%	6	10.2%	30	26.9%	6	10.2%	30	26.9%
Years/Project	2	8.9%	3	22.8%	2	8.9%	3	22.8%	2	9.3%	3	21.7%	2	9.3%	3	21.7%
Due to Production Years Lost at Remaining Projects																
Gas Quantity	248.9	5.5%	338.5	6.9%	151.5	3.4%	218.1	4.4%	1,717.1	38.0%	1,841.8	37.6%	1,566.4	34.6%	1,668.1	34.0%
Project-Years	251	21.6%	398	24.7%	166	14.3%	291	18.1%	586	50.3%	753	46.8%	499	42.9%	644	40.0%
# of Projects	22	37.3%	37	32.9%	21	35.6%	36	32.0%	33	55.9%	49	44.2%	31	52.5%	47	42.4%
Years/Project	11	57.8%	11	75.0%	8	40.1%	8	56.4%	18	90.0%	15	105.8%	16	81.6%	14	94.3%
Low Price Growth Case																
Due to Immediate Project Closures[e]																
Gas Quantity	2.6	0.1%	8.8	0.2%	2.6	0.1%	8.8	0.2%	18.7	0.4%	25.5	0.5%	18.7	0.4%	25.5	0.5%
Project-Years	7	0.6%	89	5.7%	7	0.6%	89	5.7%	11	1.0%	94	6.0%	11	1.0%	94	6.0%
# of Projects	4	6.8%	27	24.3%	4	6.8%	27	24.3%	6	10.2%	30	26.9%	6	10.2%	30	26.9%
Years/Project	2	9.1%	3	23.6%	2	9.1%	3	23.6%	2	9.5%	3	22.4%	2	9.5%	3	22.4%
Due to Production Years Lost at Remaining Projects																
Gas Quantity	287.3	6.4%	375.8	7.7%	275.5	6.1%	364.0	7.5%	1,729.1	38.4%	1,852.7	37.9%	1,729.1	38.4%	1,852.7	37.9%
Project-Years	272	23.9%	413	26.4%	241	21.2%	382	24.5%	581	51.1%	742	47.5%	581	51.1%	742	47.5%
# of Projects	22	37.3%	37	32.9%	21	35.6%	36	32.0%	33	55.9%	49	44.2%	33	55.9%	49	44.2%
Years/Project	12	64.2%	11	80.3%	11	59.6%	11	76.3%	18	91.4%	15	107.5%[f]	18	91.4%	15	107.5%[f]

a. *% of Total* values are calculated relative to baseline.
b. Gas quantity is measured in million Mcf.
c. Project-years is the sum of lost gas-production years across all projects.
d. Years/project is average number of gas-production years lost per project.
e. Slight differences in percent-change values result from differences in the baseline values against which the percent-change values are calculated. The differences in baseline values result from the change in project economics, depending on the gas-price case and the required rate of return used, and consequently, in the length of project life and the amount of gas produced during this life.
f. Results from weighting of individual projects.
Source: U.S. EPA Analysis, 2013

3.3 Uncertainties and Limitations

This analysis involves several uncertainties and limitations, each of which can lead to over- or under-estimation of impacts. Key uncertainties and limitations for the economic analysis[26] include:

- The analysis does not account for the previous outlays incurred for a project – e.g., project acquisition costs, development costs – and does not capture the subsequent tax treatment of those outlays (e.g., depletion and depreciation). Omission of these tax considerations may over- or under-state the propensity for earlier project termination.
- The analysis uses generic basin-level gas and water decline rates, which may differ from project-specific decline rates. This divergence may over- or under-state the impact of wastewater discharge requirements.
- The actual gas prices received by each project may differ from those estimated for and used in this analysis, which may over- or under-state the impact of wastewater discharge requirements.
- This analysis does not account for the possibility of additional wells being drilled at existing projects, which may over- or under-state the impact of wastewater discharge requirements. It is possible that additional wells would have improved project economics, depending on the productivity of those wells.
- This analysis does not include CBM projects that may have begun gas production since the time of the CBM survey, which may lead to underestimation of the baseline universe of existing projects.
- The individual project analyses do not begin from estimates of remaining technically recoverable gas reserves or remaining proved reserves, but use information on production at 2008 (as reported in survey responses) together with basin-specific decline rates, to estimate total potential gas production and the profile of production over time, from a project. These assumptions, which very likely differ from the actual recovery potential and production profile of the actual projects, may over- or under-state the impact of wastewater discharge requirements.
- The estimates of project costs and treatment technology costs assume no change in the underlying unit cost values on an inflation-adjusted basis – that is, costs are assumed to change in line with general inflation and past experience has shown that costs for technologies such as IX come down over time as operators become more familiar with its operation and performance and application of the technology increases. If costs change in the future in a way that differs from general inflation – whether at a higher or lower rate – then the analysis of project economics may over- or under-state the impact of wastewater discharge requirements.

[26] See the *Technical Development Document for the Coalbed Methane Extraction Industry* (DCN CBM00669) for additional details and assumptions regarding ion exchange and underground injection.

4 Economic Analysis - New Sources

As discussed in *Section 2.2.2*, the Detailed Questionnaire is the main source of data EPA used to develop model projects for the new source analysis. Because the Detailed Questionnaire obtained data at the project level, EPA conducted the new-source analysis at the level of the project. For the new-source analysis, EPA considered a project to be a group of wells that are planned, developed, and operated as a single economic production unit. The group of wells could be developed on a single lease or group of leases. To support its determinations concerning the development of ELGs for the new-source segment of CBM industry, EPA analyzed the effect of wastewater management technology options on the economics of new CBM projects. For this analysis, EPA relied on model projects that reflect resource and economic characteristics in the principal CBM production basins throughout the United States. Similar to the existing-source analysis (*Section 3*), EPA considered the IX treatment option and the UI disposal option (see *Table 2-4* for unit costs).

EPA's analysis of economic impact first assessed the economic viability of new projects independent of discharge requirements (baseline analysis). Because of the substantial decline in natural gas prices observed during the past few years, most of the model projects considered in this analysis would not be economically attractive for development in 2012, or even in the near future. However, with natural gas prices expected to increase in the future, production from these CBM basins will generally return to being economically attractive at some time in the future.[27] Nevertheless, the analysis indicates that, in some basins, a considerable number of years will need to pass (with associated increase in natural gas prices) before new projects would be viable. EPA then assessed the effect of wastewater discharge costs on the economics of CBM gas production (post-requirements analysis). This analysis looked at the potential for treatment technology and disposal costs to delay further the year in which it would be economical for CBM project developers to undertake a model project, and to affect the quantity of CBM gas that would be economically recovered from a given project. Delay and reduction in resource recovery provide important measures of the cost to society from treatment technology or disposal requirements. In addition, as described above, these adverse impacts – in particular, additional delay in the timing of economically viable production – constitute a potential *Barrier to Development* of new projects, which EPA considered in assessing whether to implement additional discharge requirements for new CBM projects.

Specifically, this analysis asked the following questions for the pre-treatment (baseline) and post-treatment, i.e., accounting for wastewater treatment and disposal costs, (post-requirements) cases:

- *Baseline analysis*:
  - Independent of potential wastewater discharge requirements, what initial price level is needed to achieve economically viable development of CBM projects?
  - In what year would that initial price level occur? What quantity of CBM gas would be economically recovered?
- *Post-requirements analysis*:
  - What initial price level is needed to achieve economically attractive development of CBM projects after imposition of ELG requirements?

[27] Given the uncertainty in future natural gas prices, EPA used alternative projections of wellhead gas prices to assess how CBM project economics would change over time (see *Appendix A*).

- By how many years would economically attractive development be delayed by the imposition of ELG requirements? What is the change in production quantity of CBM gas?

Section 4.1 reviews methodology, data sources, and assumptions for this analysis; *Section 4.2* reviews the findings from the analysis.

4.1 Methodology, Data Sources, and Assumptions

4.1.1 Summary of the Project Economic Analysis

EPA developed a general model for analyzing production economics for each of the model projects discussed in *Section 2.2.2*. This model accounts for development costs, gas production and revenue, wastewater production, and costs of producing gas and wastewater treatment. EPA developed and implemented this framework independent of the specific regulatory program considerations of this analysis. EPA then used this framework, along with projections of natural gas prices and the cost of treatment technology options, to examine potential effects of wastewater discharge requirements on project delay and total gas production.

The elements of the economic analysis for new projects are similar to those described above for existing projects, with the key distinction that the analysis for new projects starts at the *beginning* of a project, whereas the analysis for existing projects starts with the project's production levels, revenue and costs at the time of the CBM survey. Important elements for the new project analysis are as follows:

- EPA based the project economic analysis on pre-tax cash flow and the discounted NPV of that cash flow, using required rates of return as described below.[28] Being strictly a pre-tax cash analysis, the analysis does not account for income tax payments or for related tax considerations, such as depreciation and depletion. For example, the project economic analysis accounts for initial development costs and outlays for development wells only in the years that they are incurred, and these outlays do not generate any depreciation and/or depletion tax effects that would affect after-tax cash flow in subsequent years. While an after-tax analysis might provide a more precise understanding of project cash flows and related production decisions, EPA determined that the findings from the pre-tax analytic approach would not differ materially from the findings from the after-tax analysis. Moreover, an after-tax analysis would require additional assumptions about tax rates and the applicability of certain tax provisions, based on the size of the producing entity.
- In general, projects generate negative cash flow in their early years, while development wells are still being drilled, and the cash outlay for these wells exceeds the revenue received for gas production. Later, projects generate positive cash flow – if production revenue, net of certain production payments, exceeds production costs – following completion of these substantial cash outlays during the development period. Once a project's cash flow has become positive, developers are assumed to produce gas until the year in which the project's NPV is maximized. This year generally coincides with the last year – after the initial development period – in which a project's operating cash flow is positive. At this point, the project will have achieved its maximum NPV and subsequent production will generate negative cash flow and declining NPV.

28 *Pre-tax* refers to income taxes – i.e., taxes that are paid on the basis of the project's pre-tax income. Subsequent discussion refers to certain *non*-income taxes – severance tax and *ad valorem* tax – which are paid on the basis of the gross value of gas production. This analysis *does account* for these non-income tax items, which are part of the calculation of pre-tax operating income/cash flow.

- Operating cash flow during the production years is defined as gross revenue, less payments on the gross quantity or value of production, and less production costs.
  - A project's gross revenue in any year is calculated simply as the quantity of gas production *times* the wellhead price for gas in that year.
  - Gas production incurs certain payments on the gross quantity or value of production – royalty, severance tax, and *ad valorem* tax – which are charged against the gross wellhead value of gas production. These payments are subtracted from the gross value of gas production to yield a project's net revenue in any year. Based on information from the CBM survey, EPA assumed a uniform production payment percentage of 28 percent. This includes severance tax of 6 percent, royalty of 16 percent, and ad valorem tax of 6 percent. EPA calculated these payments based on the gross value of production in a given year.
  - Production costs include both the costs of producing the CBM gas and managing the produced water. This analysis calculates production costs based on fixed unit cost values so that production costs vary only with the quantities of gas and water production in a given year. In addition, for years in which development wells are being drilled, the cost of these development wells is subtracted away from the project's operating cash flow in that year.
- For calculating a project's NPV, EPA tallied project cash flows on a year-by-year basis. Initial project development costs are recorded in the first year[29]; operating cash flow, and drilling costs are recorded beginning in the second year of the project analysis, and continue for as long as drilling is underway. Production may continue for as long as 35 years. The project analysis finds the year in which a project reaches its maximum NPV, accounting for the project operating and economic information outlined in the preceding discussion.[30] The analysis assumes this year to be the last production year for a given project.
- EPA calculated a project's NPV using the same require rates of return – 17 percent and 7 percent – as used in the analysis of existing CBM projects. See the project profitability discussion in *Section 3.1.1,* for information on EPA's choice of hurdle rates for use in this analysis.

4.1.2 Price Projections

The purpose of this analysis is to understand the baseline economics of CBM gas production across the various CBM basins, and to see how those economics would change if projects incurred the costs for wastewater treatment technology, as outlined above. The potential for adverse impact due to wastewater discharge requirements constitutes a Barrier to Development, which EPA used as a key consideration in assessing whether to develop discharge regulations applicable to new CBM sources.

A key consideration in this analysis is the expected prices for natural gas produced in various locations across the United States. As noted above, in recent years, natural gas prices have been considerably below the peak in 2008. As a result, some of the model projects would not be economically viable for development at current prices. However, with natural gas prices expected to increase, in both nominal and

[29] In reality, initial development outlays may occur over several years as a developer assembles development rights and acquires permits and capital for undertaking the project. For this analysis, EPA recorded these outlays as though they all occur in a single year.

[30] Distinct from the existing source analysis, the new sources analysis recognizes the possibility that a project may experience years of negative cash flow that are followed by years with positive cash flow, in finding the year in which NPV is maximized.

constant dollar terms, in future years, these projects will likely offer economically viable development opportunities at some time in the future. Accordingly, this analysis accounts for the expected increase in natural gas prices over time, and examines (1) when the various model projects would become economical to develop and (2) the quantity of CBM gas that each of the model projects would produce.

To support this analysis, EPA developed and used natural gas price projections, based on analyses from AEO publications and natural gas price data. Specifically, EPA developed basin-specific price projections based on three different DOE projection cases, to account for the inherent uncertainty in projecting natural gas prices.[31] EPA then used these wellhead price series to calculate the compound annual growth rate (CAGR) over the 28-year period from 2013 to 2040 for each of the price cases. EPA began these projections from 2013 to capture the expected change in natural gas prices beginning from the present and continuing into future years, thus reflecting the price changes that CBM project developers would experience and/or anticipate in assessing new project opportunities. *Table 4-1* reports the starting and end values and resulting annual growth rates. These values define the *price paths* used in the analysis described below.

Table 4-1: Compound Annual Growth Rates for Natural Gas Wellhead Prices , 2013- 2040

Gas-Price Case	2013 Natural Gas Price ($2010)	2040 Natural Gas Price ($2010)	CAGR
Low Economic Growth	$3.07	$6.87	3.0%
Reference	$3.17	$7.52	3.3%
High Economic Growth	$3.21	$8.01	3.4%

1. Appalachian Basin wellhead prices are used as an example for this calculation.
2. The CAGR does not vary by basin.
Source: U.S. EPA Analysis, 2013

4.1.3 Estimating the Potential for Delay and Reduced CBM Gas Production Due to Treatment Technology Costs

This analysis finds the initial wellhead price that, when coupled with a given price path, would cause a given model project to be economically viable to undertake. EPA then found the calendar year in which this price would occur, based on the specific EIA-based price projection underlying the analysis. EPA also identified the calendar year in which a model project would cease production, given the price path and other project economic specifications. With information on the beginning and end of a project, EPA tallied the total quantity of CBM gas that would be economically produced from the project. EPA performed this analysis for the baseline case – i.e., with no additional cost from discharge requirements – and then for cases including the additional cost from discharge requirements.

The general project analysis framework, outlined at *Section 4.1.1*, above, simulates the economics of CBM gas production over time, and the developer's decision of when to terminate production given the project's operating cash flow profile. The analysis assumes that developers make production decisions according to the principle of maximizing the NPV of pre-tax cash flow, and, based on this principle, produce gas through the year in which project NPV is maximized.

Starting from this general framework, the analysis proceeds as follows:

- Solve for the lowest starting wellhead price (and associated price path) that yields non-negative NPV over the project analysis period, which includes the initial development years *and* the years following initial development. The analysis period may include years of negative cash flow,

[31] For information on the development of the price projections, see *Appendix A*.

particularly during the early project years when development wells are being drilled. The solution for lowest starting wellhead price reflects the implicit price path, based on the CAGRs for the EIA price projections. The following discussion refers to the lowest starting wellhead price that yields non-negative NPV, as the *breakeven starting price*.

- EPA assumed that the project ceases production following the year in which NPV is maximized. Beyond this year, operating cash flow becomes negative and subsequent production reduces the NPV below the maximum achievable value. Total gas production for the project is simply the sum of CBM gas production quantities over this production life.

- EPA then found the actual calendar year, for the associated basin-specific EIA price case, in which the starting breakeven price would occur. As noted in *Appendix A*, EPA extended the price forecasts through 2050, to allow identification of breakeven price years that are after 2040.

- This analysis yields the following key outputs: starting breakeven price, year of occurrence (*economical production year*), and total quantity of CBM gas produced.

EPA performed this analysis for the following case specifications:

- By model project
- By EIA gas-price case
- By required rate of return (7 and 17 percent)

EPA first performed the baseline analysis, followed by the post-requirements analysis. As key output metrics for these analyses, EPA calculated:

- <u>The delay in economical production year between baseline and post-requirements cases.</u> EPA found that most new projects are not economically viable under current natural gas prices, but would become viable in a future year as a result of increasing natural gas prices – that is, new projects would be *delayed* independent of wastewater treatment requirements. When EPA found that wastewater discharge requirements would further delay viable development of these projects, EPA termed this delay the *additional delay*. This additional delay constitutes a potential *Barrier to Development* of new projects and is a key consideration in assessing the economic impact of potential wastewater discharge requirements on new CBM projects.

- <u>The change in total CBM gas production between baseline and post-requirements cases.</u> Potential reductions in gas production for a given model project because of discharge requirements constitutes an additional adverse economic impact. EPA accounted for such reductions as part of the Barrier to Development analysis.

4.2 Analysis Results

The following sections summarize the analysis findings:

- *Section 4.2.1* summarizes the results of the analysis using a 17-percent required rate of return (hurdle rate). *Table 4-2* reports these analysis results.

- *Section 4.2.2* summarizes the results of the analysis using a 7-percent required rate of return (hurdle rate). *Table 4-3* reports these analysis results.

Unlike the presentation of results for the existing projects analysis, EPA reports these results separately by required rate of return/hurdle rate case because of the additional information presented in the new sources analysis – in particular, focusing on the delay in economical production year.

4.2.1 Using 17-Percent Required Rate of Return (Hurdle Rate)

For the baseline analysis, none of the model projects are currently economically viable, regardless of basin.[32] The Green River and Powder River Basins' primary model projects (GR1 and PRB1) are not viable at baseline for any of the price growth cases. The Raton model project (Raton1) is not economical at baseline only under the low price growth case. For the other model projects and price growth cases, the projects become viable within the period of the analysis, with the economical production years ranging from 2018 and 2049. Economical production years and delay beyond 2013 are as follows:

- The secondary Appalachian model project (APP2) has the earliest economical production years, 2018 to 2023 or a delay of 5 to 10 years beyond 2013, depending on price case. Economical production years for the primary Appalachian model project (APP1) are later, at 2040 to 2044 or a delay of 27 to 31 years beyond the present.
- For the Illinois basin model projects (ILL1 and ILL2), the earliest production years are 2041 to 2045, or a delay of 28 to 32 years beyond 2013.[33]
- For the Black Warrior/Cahaba basin model projects (BW1, BW2, Cahaba1, Cahaba2), the earliest production years are 2026 to 2035, or a delay of 13 to 22 years beyond 2013.
- For the Powder River Basin secondary model project (PRB2), the earliest production years are 2026 to 2035, or a delay of 13 to 22 years beyond 2013.
- For the Raton basin model project (Raton1), the earliest production years are 2048 to 2049, or a delay of 35 to 36 years beyond 2013, for the reference and high price growth cases.

For the IX treatment technology option, the economical production year is additionally delayed from zero years to a maximum of 20 years for projects that become economical before 2050. The model project additional delay effects are as follows:

- The Appalachian basin primary model project experiences no additional delay in economical production years, the secondary model project (APP2) experiences an additional delay of 1 to 2 years.
- The Illinois basin model projects (ILL1 and ILL2) experience no additional delay.
- The Black Warrior/Cahaba basin model projects (BW1, BW2, Cahaba1, Cahaba2) experience additional delays of 1 to 4 years.

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32 In contrast to the finding in the existing project analysis that some existing projects remain economically viable, the new project analysis found that new projects are not currently viable because these projects would need to incur all of the project development costs – i.e., lease acquisition, project planning, and drilling of wells. In the existing project analysis, projects have already incurred these costs and they do not enter into the assessment of economic viability of continued production for existing projects: for the existing project analysis, these costs are considered *sunk* and are not accounted for in assessing the viability of existing projects. This distinction is very important in assessing the viability of existing and new projects: new projects *have not already incurred these costs* and a projects' production economics must support incurrence of these substantial upfront costs in order for new projects to be economically viable.

33 Although the Appalachian and Illinois model projects are the same, the baseline (and post-requirements) results differ slightly because of the assignment of different natural gas prices and price paths to the basins. The prices and price paths are mapped to basins based on the specific states within a basin. The prices for the Illinois basin are based on wellhead prices in Kentucky, Indiana and Illinois, while the Appalachian basin reflects Kentucky, Tennessee, Ohio, Pennsylvania, Virginia and West Virginia. This result differs from the Black Warrior and Cahaba basins, which also use the same model project and, with both basins being in Alabama, *the same prices*. As a result, the analysis findings for Black Warrior and Cahaba are identical. See discussion at *Section 2.2.2*, page 8.

- The Powder River Basin secondary model project (PRB2) experiences additional delay of 14 to 20 years.
- The Raton basin model project experiences additional delay of 2 years under the high price growth case; the estimated additional delay extends beyond the end of the analysis period for the reference and low price growth cases.

In cases where there is a range in the number of additional-delay-years for a given basin, the range results from the different price growth cases.

Gas production effects are generally small, and occur as increases, ranging from no change to an increase of nearly 3 percent. The finding that production increases with the addition of technology option costs is at first counter-intuitive. However, on closer inspection, the increased production results from the higher breakeven price that is required for the technology option case than for the baseline (no additional cost) case. Even though prices grow at the same year-over-year CAGR under both cases, the simple numerical slope of the price path that begins from the higher breakeven price (required for the technology option case) increases more rapidly than the slope under the price path that begins from the lower breakeven price (for the baseline case). The greater increase, year-over-year, in the simple slope means that project economics improve more rapidly in out-years for the higher breakeven price case, and that the production life can be extended for this case with the higher price (and revenue increases) compared to the lower breakeven price case. Of importance, even though gas production may increase in some of the analysis cases, the increase occurs with a delay in production, and accordingly, a delay in realization of the economic benefit to society from natural gas production: on a *discounted present value* basis, the quantity and economic value from natural gas production may be less under the post-requirements case *even though a larger quantity of gas is produced*.

For the UI disposal option, which is generally more expensive than the IX technology option, the additional delays in economical production year are greater than under the IX technology option. The economical production year is additionally delayed from a minimum of 1 year to a maximum of 21 years for projects that become economical before 2050. The model project additional delay effects are as follows:

- The Appalachian basin primary model (APP1) project experiences additional delay of 1 to 2 years; the secondary model project (APP2) experiences additional delay of 10 to 13 years.
- The Illinois basin model projects (ILL1 and ILL2) experience additional delays of 1 to 2 years.
- The Black Warrior/Cahaba basin primary model project (BW1, Cahaba1) experiences additional delays of 11 to 16 years; the secondary model project (BW2, Cahaba2) experiences additional delays of 6 to 10 years.
- The Powder River Basin secondary model project (PRB2) experiences additional delay of 15 to 21 years.
- The estimated additional delay for the Raton basin model project extends beyond the end of the analysis period.

The gas production effects are more substantial with UI disposal than with IX treatment. Again, these effects are due to increased gas production, which, as described above, results from the additional delay in economical production year and the assumption of constant percentage growth in natural gas prices.

Table 4-2: Effect of Wastewater Discharge Requirements on New CBM Projects, Using 17 Percent Hurdle Rate[a]

Model Project	Baseline: First Year in Which Production Is Economical	Baseline: Production (MMcf)	Basis: Ion Exchange (IX): Delay in First Year of Production (years)	Basis: Ion Exchange (IX): Change in Production (%)	Basis: Underground Injection (UI): Delay in First Year of Production (years)	Basis: Underground Injection (UI): Change in Production (%)
High Price Growth Case						
APP1	2040	88,682	0	0.0%	2	0.0%
APP2	2018	47,577	1	0.0%	10	1.3%
ILL1	2041	88,682	0	0.0%	2	0.0%
ILL2	2041	47,577	0	0.0%	2	1.3%
BW1/Cahaba1	2026	147,863	4	0.0%	16	0.0%
BW2/Cahaba2	2026	1,148,990	2	2.8%	10	22.8%
GR1	after 2050	NA	after 2050	NA	after 2050	NA
PRB1	after 2050	NA	after 2050	NA	after 2050	NA
PRB2	2026	18,541	20	0.0%	21	0.0%
Raton1	2048	61,506	2	0.0%	after 2050	NA
Reference Case						
APP1	2042	88,682	0	0.0%	1	0.0%
APP2	2020	47,315	2	0.6%	13	1.9%
ILL1	2043	88,682	0	0.0%	1	0.0%
ILL2	2043	47,315	0	0.6%	1	1.9%
BW1/Cahaba1	2032	147,863	2	0.0%	12	0.0%
BW2/Cahaba2	2031	1,118,228	2	2.7%	7	22.6%
GR1	after 2050	NA	after 2050	NA	after 2050	NA
PRB1	after 2050	NA	after 2050	NA	after 2050	NA
PRB2	2030	18,541	17	0.0%	18	0.0%
Raton1	2049	61,506	after 2050	NA	after 2050	NA
Low Price Growth Case						
APP1	2044	88,682	0	0.0%	1	0.0%
APP2	2023	47,024	2	0.6%	13	2.1%
ILL1	2045	88,682	0	0.0%	1	0.0%
ILL2	2045	47,024	0	0.6%	1	2.1%
BW1/Cahaba1	2035	147,863	2	0.0%	11	0.0%
BW2/Cahaba2	2035	1,082,291	1	2.7%	6	22.5%
GR1	after 2050	NA	after 2050	NA	after 2050	NA
PRB1	after 2050	NA	after 2050	NA	after 2050	NA
PRB2	2035	18,541	14	0.0%	15	0.0%
Raton1	after 2050	NA	after 2050	NA	after 2050	NA

a. EPA conducted analyses of new projects only for projects where the first year in which production is economical is within the period from 2010 to 2050. The analysis stops at 2050.

Source: U.S. EPA Analysis, 2013

4.2.2 Using 7-Percent Required Rate of Return (Hurdle Rate)

The baseline analysis using the 7-percent required rate of return differ slightly from those developed for the 17-percent rate, with the economical production years generally earlier than the value estimated for the 17-percent rate. At the 7-percent rate, the Appalachian, Black Warrior and Cahaba secondary model projects (BW2/Cahaba2 and APP2) are already economical, while the analysis using under the 17 percent rate found no model projects to be currently economical. Other model projects would become economical between 2016 and 2045. Using the 7-percent rate, only the Green River basin model project is not currently economical at baseline.

Economical production years and delay beyond 2013 are as follows:

- The analysis indicates that the secondary Appalachian model projects (APP2) is currently economical under all price cases. Economical production years for the primary Appalachian model project (APP1) are later, at 2028 to 2036 or a delay of 15 to 23 years beyond 2013.
- For the Illinois basin model projects (ILL1 and ILL2), the earliest production years are 2030 to 2037, or a delay of 17 to 24 years beyond 2013.
- The analysis indicates that the secondary Black Warrior/Cahaba basin model projects (BW2, Cahaba2) are currently economical with the reference and high price growth cases. Under the low price growth case, the economical production year for BW2 and Cahaba2 is delayed to 2016. For the primary Black Warrior/Cahaba basin model projects (BW1, Cahaba1), the earliest production years are 2016 to 2018, or a delay of 3 to 5 years beyond 2013.
- For the Powder River Basin primary model project (PRB1), the earliest production years are 2041 to 2045, or a delay of 28 to 32 years beyond 2013. For the Powder River Basin secondary model project (PRB2), the earliest production years are 2022 to 2028, or a delay of 9 to 15 years beyond 2013.
- For the Raton basin model project (Raton1), the earliest production years are 2036 to 2041, or a delay of 23 to 28 years beyond 2013.

For the IX treatment technology option, the economical production year is additionally delayed from zero years to a maximum of 23 years for projects that become economical before 2050. The model project additional delay effects are as follows:

- The Appalachian basin primary model project experiences no additional delay in economical production years under the high and low price growth cases, and a one to year additional delay under the reference price growth case. The secondary Appalachian basin model project (APP2) experiences no delay in economical production year.
- The Illinois basin model projects (ILL1 and ILL2) experience no additional delay under the low price growth case and an additional delay of one year under the reference and high price growth cases.
- The Black Warrior/Cahaba basin model projects (BW1, BW2, Cahaba1, Cahaba2) experience no additional delay under the high price growth case, and additional delays of 1 to 6 years under the reference and low price growth cases.
- The Powder River Basin primary model project (PRB1) experiences an additional delay of 2 years, while the secondary model project (PRB2) experiences additional delay of 19 to 23 years.
- The Raton basin model project experiences additional delay of 3 years.

As stated above, in cases where there is a range in the number of delay-years for a given basin, the range results from the different price growth cases.

Gas production effects are somewhat greater under the 7-percent required rate of return than under the 17-percent rate, and, again, occur as increases, ranging from no change to an increase of nearly 13 percent.

As observed for the 17-percent required rate of return, additional delays in economical production year are greater with UI disposal than with IX treatment. The economical production year is additionally delayed from a minimum of 1 year to a maximum of 24 years for projects that become economical before 2050. The model project additional delay effects are as follows:

- The Appalachian basin primary model (APP1) project experiences additional delay of 1 to 5 years; the secondary model project (APP2) experiences additional delay of 8 to 13 years.
- The Illinois basin model projects (ILL1 and ILL2) experience additional delays of 1 to 4 years.
- The Black Warrior/Cahaba basin primary model project (BW1, Cahaba1) experiences additional delays of 18 to 20 years; the secondary model project (BW2, Cahaba2) experiences additional delays of 9 to 12 years.
- The Powder River Basin primary model project (PRB1) experiences additional delay of 2 to 3 years. The Powder River Basin secondary model project (PRB2) experiences additional delay of 20 to 24 years.
- The Raton basin model project experiences additional delays of 3 to 4 years.

Also as described for the 17-percent rate analysis, the gas production effects are more substantial with UI disposal than with IX treatment, with production effects ranging from zero to 28 percent. Again, these effects are to increase gas production, which results from the additional delay in economical production year and the assumption of constant percentage growth in natural gas prices.

Table 4-3: Effect of Water Discharge Requirements on New CBM Projects, Using 7 Percent Hurdle Rate[a]						
	Baseline		Ion Exchange (IX)		Underground Injection (UI)	
Model Project	First Year in Which Production Is Economical	Production (MMcf)	Delay in First Year of Production (years)	Change in Production (%)	Delay in First Year of Production (years)	Change in Production (%)
High Price Growth Case						
APP1	2028	88,682	0	0.0%	5	0.0%
APP2	2010	45,500	0	1.0%	8	4.0%
ILL1	2030	88,682	1	0.0%	4	0.0%
ILL2	2030	45,500	1	1.0%	4	4.0%
BW1/Cahaba1	2016	147,863	0	0.0%	18	0.0%
BW2/Cahaba2	2010	454,634	0	3.3%	9	27.6%
GR1	after 2050	NA	after 2050	NA	after 2050	NA
PRB1	2041	53,151	2	0.0%	2	0.0%
PRB2	2022	17,463	22	6.2%	23	6.2%
Raton1	2036	61,506	3	0.0%	4	0.0%
Reference Case						
APP1	2033	88,682	1	0.0%	2	0.0%
APP2	2010	45,500	0	1.0%	10	3.3%
ILL1	2034	88,682	1	0.0%	2	0.0%
ILL2	2034	45,500	1	1.0%	2	3.3%
BW1/Cahaba1	2016	147,863	2	0.0%	20	0.0%
BW2/Cahaba2	2010	444,788	6	3.3%	12	27.5%
GR1	after 2050	NA	after 2050	NA	after 2050	NA
PRB1	2042	53,151	2	0.0%	3	0.0%
PRB2	2023	17,463	23	6.2%	24	6.2%
Raton1	2038	61,506	3	0.0%	4	0.0%
Low Price Growth Case						
APP1	2036	88,682	0	0.0%	1	0.0%
APP2	2010	45,500	0	0.0%	13	3.3%
ILL1	2037	88,682	0	0.0%	1	0.0%
ILL2	2037	45,500	0	0.0%	1	3.3%
BW1/Cahaba1	2018	147,863	2	0.0%	20	0.0%
BW2/Cahaba2	2016	433,136	1	3.3%	10	27.3%
GR1	after 2050	NA	after 2050	NA	after 2050	NA
PRB1	2045	53,151	2	0.0%	2	0.0%
PRB2	2028	16,426	19	12.9%	20	12.9%
Raton1	2041	61,506	3	0.0%	3	0.0%

a. EPA conducted analyses of new projects only for projects where the first year in which production is economical is within the period from 2010 to 2050. The analysis stops at 2050.

Source: U.S. EPA Analysis, 2013

4.3 Uncertainties and Limitations

Like the existing project analysis, the new project analysis is subject to a range of uncertainties and limitations, which may lead to over- or under-estimation of the impact of treatment technologies on the economics of new CBM projects. Key uncertainties and limitations for the economic analysis[34] include:

- The analysis uses relatively simple basin-level models to assess project economics in the baseline and with installation of treatment technology. These models cannot capture all of the complexities of CBM project development and production. In addition, the models and the assumptions of the analysis cannot replicate the decision process of developer/operators in deciding such matters as:

[34] See the *Technical Development Document for the Coalbed Methane Extraction Industry* (DCN CBM00669) for additional details and assumptions regarding ion exchange and underground injection.

whether and when to develop a CBM gas opportunity; how to develop it in terms, for example, of number of wells and timing of wells; and when to shut down production. EPA's analysis based on the model projects provides valuable insight into the economics of production across basins; nevertheless, the resource characteristics and production economics of actual CBM projects are likely to differ, perhaps substantially, from the model projects used in this analysis. As a result, the findings of impact from discharge requirements on project economics may be greater or less than the impacts that would occur with actual CBM projects.

- The analysis uses a relatively simple, deterministic framework to estimate gas production and project economic performance over time. Omission of the uncertainties in production, prices, and costs may lead to lead to over- or under-estimation of the impact of wastewater discharge requirements on project economics and develop/operator decisions.
- The actual gas prices received by each project likely differ from those estimated for and used in this analysis, which may over- or under-state the impact of wastewater discharge requirements.
- The estimates of project costs and treatment technology option costs assume no change in the underlying unit cost values on an inflation-adjusted basis – that is, costs are assumed to change in in line with general inflation. If costs change in the future in a way that differs from general inflation – whether at a higher or lower rate – then the analysis of project economics may over- or under-state the impact of wastewater discharge requirements.
- EPA completed this analysis on a pre-tax basis, which means that the analysis does not account for potential effects of tax considerations on project development, production, and termination decisions. Omitting these considerations from the analysis could lead to over- or under-estimation of the impact of wastewater discharge requirements on project economics and develop/operator decisions.

Conclusion

Overall, this analysis shows that based on the 2008 CBM survey data and a 2010 data review, a large fraction of existing CBM projects are no longer economically viable, independent of the wastewater discharge requirements considered in this analysis. Specifically, EPA estimated that approximately 25 percent of existing CBM projects either closed immediately in 2008 or were non-operational by 2010. EPA expects that an additional 43 percent of the existing CBM projects reported in 2008 were shut down by 2012. The deteriorating economic viability of these projects results largely from declining natural gas prices since the time of the CBM survey.

For the analysis of the impact of wastewater discharge requirements on existing projects, EPA focused on the 112 CBM projects that were found economically viable out of the 148 total projects given the 23 immediate baseline closures estimated through the 2008 assessment and 13 projects found non-operational in 2010. Of these 112 CBM projects, EPA found that the wastewater technology options considered in this analysis would lead to immediate or earlier shutdown of CBM projects and losses in gas production than would occur in the absence of technology costs. Specifically, EPA estimated that under the IX treatment option, 24 percent of the 112 projects estimated to be economically viable in the baseline would shut down immediately, with an additional 26 to 33 percent experiencing losses in production life. Under the UI disposal option, 27 percent of the 112 economically viable projects would shut down immediately, with an additional 38 to 44 percent experiencing losses in production life. In general, because UI disposal costs are higher than IX treatment costs, the loss in production life and quantity is greater under the UI option than that under the IX treatment option.

Further, this analysis found that new CBM projects in most CBM gas basins are not economically viable at current natural gas prices, independent of the wastewater discharge requirements considered in this analysis. For most basins and analysis cases, natural gas prices need to increase substantially above currently low levels before new CBM projects become economically viable. If CBM developers seek a level of financial return indicated to EPA by CBM industry representatives (17 percent), projects are not currently viable in any of the CBM basins analyzed under a range of natural gas price growth cases. Using the rate of return of 17 percent indicated by CBM project developers, new projects would not be viable until 2018 – 2049 with most new projects delayed by at least 30 years. For the 7-percent required rate of return case, CBM projects appear currently viable in only three of the seven discharging CBM basins, and these instances most often occur under higher natural gas price growth cases.

Accounting for costs of the wastewater discharge requirements considered in this analysis generally lengthens the delay until new CBM projects would become economically viable. Under either the IX treatment or UI disposal options, additional delays before projects would be economically viable – beyond the delays already discussed above for new projects to become viable even without such requirements – range from zero years to over 20 years. For the IX treatment option, using industry's indicated rate of return of 17 percent, most model projects experience an additional delay of two years. Under the more expensive UI disposal option, additional delays range from 1 to more than 20 years. Using the 17-percent rate of return, most projects experience a delay of over 20 years. In summary, the addition of wastewater discharge requirements would substantially burden the economic/financial performance of new CBM projects, and would further delay project viability by a significant number of years for most projects, regardless of the natural gas growth cases or the financial return sought by CBM project developers.

Overall, EPA found that applying wastewater discharge requirements would impose significant burdens in terms of immediate or early shutdown and loss of gas production from the projects that remained economically viable at 2008 and 2010. For new projects, EPA reached the following findings: (1) CBM projects do not generally appear economically viable at present, and for many development opportunities, for substantial periods into the future, and (2) discharge requirements would further delay these projects' economic viability.

Given these findings for both existing and new sources, EPA's judgment at this time is that it should not move forward with additional regulation of wastewater discharges from CBM projects. Pending changes in CBM gas production economics, and increased volume of CBM activity and wastewater discharges, and possible changes in the available wastewater management approaches and/or associated costs, EPA may revisit this decision in future years.

Appendix A Developing Wellhead Price Forecasts

The existing- and new-source economic analyses rely on projections of natural gas prices to assess how CBM project economics would change over time, and to estimate how treatment technology option costs would affect project economics. The two analyses use price projections as follows:

- For the existing-source analysis, EPA collected 2008 wellhead prices, by project, in the CBM survey.[35] To estimate future revenue for existing projects, EPA began from the survey-reported prices but needed estimates of how natural gas prices would change over time to forecast project-specific prices beyond the survey-reported values.
- For the new-source analysis, EPA again needed future prices for natural gas that new CBM projects would receive for gas sold. Because the new project analysis does not begin from a price reported in the CBM survey, however, EPA needed both starting price values and how those prices would change over time to forecast prices and revenue that would be received by new projects. In addition, as described in *Section 4.1.2*, EPA developed natural gas price paths, which reflect the average expected growth rate in wellhead prices from the present (2013) through 2040, for the new project analysis. EPA used these price paths to estimate when new CBM projects would become economically viable, by basin, starting wellhead price, and required rate of return.

For both the existing- and new-source analyses, the appropriate price concept for these prices is an upstream price, specifically wellhead price.

Price projections are inherently uncertain. To account for this uncertainty, EPA developed three price growth cases, based on AEO gas-price projections. The three price growth cases are as follows:

- *Reference case*, which draws directly from the natural gas reference case. This case assumes an annual increase of 2.5 percent in GDP between 2010 and 2035, while real disposable income per capita grows at 1.5 percent per year.
- *A High Price-Growth case*, which is based on AEO's *high economic growth case*. This case assumes an annual GDP growth of 3.0 percent and an annual increase in real disposable income per capita of 1.6 percent, between 2010 and 2035.
- *A Low Price-Growth case*, which is based on AEO's *low economic growth case*. This case assumes an annual increase of 2.0 percent in GDP and an annual increase of 1.3 percent in real disposable income per capita between 2010 and 2035.

In addition to these cases, EIA provides other natural gas price forecasts, which are defined on various parameters, for example, the quantity of natural gas resources determined as technically and economically recoverable over the next few decades. EPA chose the high and low economic growth cases as providing reasonable upper and lower price growth cases for economic analysis.

This appendix describes the methodology and data used to develop the estimated year-over-year changes in wellhead prices, as used in the both the existing- and new-source analyses: the starting price values, by basin, as used in the new-source analysis; and the price path growth rates, also as used in the new-source analysis.

[35] For more information on the CBM survey see http://water.epa.gov/scitech/wastetech/guide/cbm_index.cfm.

A.1 Available Data

EPA used the following EIA data to calculate national-level and basin-specific projections:

- Historical wellhead prices by state (U.S. DOE, 2012c)
- U.S. wellhead prices for 2008 from Annual Energy Outlook (U.S. DOE, 2011a)
- Henry Hub and wellhead Reference case, High Economic Growth case, and Low Economic Growth case price projections for the United States, for the period 2009 to 2035, from Annual Energy Outlook (U.S. DOE, 2012a)
- Henry Hub wellhead Reference case price projections for the United States, for the period 2010 to 2040, from AEO 2013 Early Release (U. S. DOE, 2012b)

The price projections from AEO 2013 Early Release are EIA's most current estimates of future natural gas prices. However, EIA's Early Release data are limited in several ways compared to the previous release. The Early Release forecasts are for the Reference case only; are at the national level only; and are published as Henry Hub prices, which is downstream from the wellhead, and not the price concept needed for the impact analyses. Despite these limitations, EPA decided to use the 2013 Early Release data for this analysis, with certain adjustments. Apart from being one-year more recent than the previous price series, of particular note is the fact that the 2013 Early Release data extend the forecast an additional five years into the future, compared to the previous forecast series.

To obtain price projections appropriate for the CBM impact analyses, EPA applied a number of adjustments, described below, to the AEO 2013 Early Release data.

A.2 Price Adjustments

The following sections describe gas-price adjustments first for the existing-source analysis, and then for the new-source analysis. The steps in developing the price growth paths for the new-source analysis build from the methodology outlined for the existing-source analysis.

A.2.1 Existing-Source Analysis

For the existing-source analysis, EPA developed price projections, and associated estimates of year-over-year changes in prices, by making the following adjustments to the AEO 2013 Early Release data:

1. Using AEO 2012 price projections (i.e., the previous year's forecast) for 2008 to 2035, [36] project DOE prices for the years 2036 through 2040 for each of the price growth cases. EPA made this projection based on the compound annual growth rate (CAGR) for the last five years provided (2030 to 2035), and used the calculated CAGR to project prices for the years 2036 to 2040.[37] EPA completed this step for both Henry Hub and wellhead prices.

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[36] For the existing project analysis, EPA relied on the full range of annual price projections reported in AEO 2012 (2009 to 2035) and added 2008 price data from AEO 2011 to extend prices from 2008 to 2035.

[37] In EIA's High Economic Growth case, natural gas prices decline steeply in natural gas in 2035 due to an assumed influx of gas from the Alaskan Natural Gas Transportation System will occur and drive down prices. Following conversation with EIA, EPA dropped the price data for this year in developing its High Price Growth case, as EIA is no longer assuming that this significant external event will occur in developing the AEO 2013 price forecasts (Joe Benneche, personal communication, December 12, 2012). Instead, for the High Price Growth case, EPA used data for the years 2010 to 2034 *from EIA's High Economic Growth Case*, and projects price data beyond 2034 using the CAGR for the five-year period from 2029 to 2034.

2. Using the AEO 2012 price growth paths developed for 2008 to 2040,[38] calculate year-by-year price differentials, using Henry Hub prices, between the Reference case and the alternative price growth cases.
3. Apply these year-by-year price differentials to the AEO 2013 Reference case price projection for 2008 to 2040 to develop national, Henry Hub projections for the two alternative price growth cases to be used in this analysis (High Price-Growth Case and Low Price-Growth Case), based on the newer AEO price series. This adjustment assumes that the year-by-year differentials between the Reference Case and the alternative price growth cases from AEO 2012, will also apply to the AEO 2013 data.
4. Using the AEO 2012 price projections developed for 2008 to 2040, calculate the annual price differentials between Henry Hub and wellhead prices for each of the price cases. Apply these price differentials to the AEO 2013 price projections developed for 2008 to 2040 to convert the projections based on the 2013 Early Release from Henry Hub to wellhead prices, for each of the price growth cases. This adjustment assumes that the differential between Henry Hub and wellhead prices from the AEO 2012 forecasts, will also apply to the AEO 2013 data.
5. Calculate the CAGR values for the period 2035-2040 from each of the adjusted price growth cases; use these CAGR values to project wellhead prices for all price forecast cases from 2040 to 2050.
6. Calculate the year-over-year percent change in prices for each of the price growth cases, for the years 2008 to 2042 (see *Table A.2-1*).

Table A.2-1: Year-Over-Year Percent Changes in Gas Wellhead Prices

Year	Low	Reference	High
2008	na	na	na
2009	-54.6%	-54.6%	-54.6%
2010	10.7%	10.7%	10.7%
2011	-9.5%	-9.5%	-9.5%
2012	-37.8%	-37.2%	-37.0%
2013	17.5%	20.3%	21.5%
2014	-7.6%	-5.3%	-5.6%
2015	-1.6%	-0.7%	0.7%
2016	16.4%	16.9%	18.2%
2017	3.4%	4.5%	4.0%
2018	8.6%	7.7%	8.6%
2019	1.5%	2.0%	2.7%
2020	1.8%	2.0%	3.2%
2021	2.1%	2.5%	3.1%
2022	4.6%	4.8%	4.7%
2023	3.3%	4.1%	5.0%
2024	2.7%	2.5%	2.5%
2025	0.5%	1.4%	2.4%
2026	2.3%	3.1%	4.3%
2027	1.3%	0.9%	0.4%
2028	2.3%	2.7%	2.9%
2029	0.7%	1.3%	0.8%
2030	1.9%	1.7%	1.8%
2031	2.1%	2.4%	2.5%
2032	1.2%	1.7%	0.8%

38 National price data for 2008 through 2011 are EIA modeled prices and may vary from EIA reported historical prices for those years.

Table A.2-1: Year-Over-Year Percent Changes in Gas Wellhead Prices

Year	Low	Reference	High
2033	4.2%	2.5%	4.2%
2034	2.7%	4.2%	4.0%
2035	5.8%	4.6%	2.9%
2036	6.6%	6.2%	5.6%
2037	5.8%	5.4%	5.0%
2038	6.0%	5.6%	5.2%
2039	2.0%	2.0%	1.8%
2040	3.1%	3.0%	2.8%
2041	4.7%	4.4%	4.1%
2042	4.7%	4.4%	4.1%

Source: U.S. EPA Analysis,2013; U.S. DOE, 2011a; U.S. DOE, 2012a; and U.S. DOE, 2012b

7. Apply year-over-year percent change in prices to 2008 average wellhead price for each project, for each price growth case, to develop project-specific prices for each analysis year.

A.2.2 New-Source Analysis

Because of the issues associated with the Early Release forecasts, as noted above, EPA needed to perform the following adjustments to develop basin-specific wellhead price paths for the new-source analysis:

1. Develop a national-level price projection for each of the price cases, for the years 2010 to 2050, using Step 1 through Step 5 from the adjustments listed above.
2. Restate prices from 2011 dollars to 2010 dollars (the analysis year) using GDP deflator series.
3. Develop wellhead prices by basin by mapping the average annual wellhead prices by state, for 2010, to the CBM basins, and averaging the state-level prices for each basin.[39] These prices provide the basin-specific price values to which the profiles of price change, from the national-level price forecasts, are applied in developing basin-specific forecasts, as described in the next step.
4. Calculate the year-over-year percentage change for each of the national wellhead price cases, for the period 2010-2050.
5. Apply these year-over-year percentage changes for each price case to the average wellhead price per basin to develop the three price projections from 2010 to 2050 for each basin analyzed. The resulting values are approximate wellhead natural gas prices in 2010 dollars, by CBM basin. These values build from the 2013 Early Release price forecast profile, and retain the year-by-year differentials between the Reference Case and alternative growth cases *and* the year-by-year differentials between Henry Hub prices and wellhead price – both as observed in the complete price dataset from AEO 2012.

The following tables report the basin-specific price projections that EPA developed for each of the price growth cases, and used in the new project analysis. As reflected in the tables, EIA projects volatility in natural gas prices in the short term with a sharp decline into 2012, a significant increase in 2013, and then another period of decline into 2015. In the longer term, prices grow steadily, beginning to rise at a higher rate in the early 2030s.

[39] EPA relied on actual historical state-level prices reported by EIA for the year 2010.

Table A.2-2: Basin Specific Price Projections for the Reference Case (CAGR of 3.3%)						
Year	**APP (VA, WV, PA, OH)**	**BW and Cahaba (AL)**	**GR (WY, CO)**	**PRB (MT, WY)**	**Raton (CO, NM)**	**Illinois (IL, IN)**
2010	$4.63	$4.46	$4.13	$3.97	$4.64	$4.13
2011	$4.19	$4.04	$3.74	$3.59	$4.20	$3.74
2012	$2.63	$2.53	$2.35	$2.26	$2.64	$2.35
2013	$3.17	$3.05	$2.82	$2.71	$3.17	$2.82
2014	$3.00	$2.89	$2.68	$2.57	$3.01	$2.68
2015	$2.98	$2.87	$2.66	$2.55	$2.98	$2.66
2016	$3.48	$3.35	$3.10	$2.98	$3.49	$3.10
2017	$3.63	$3.50	$3.24	$3.12	$3.64	$3.24
2018	$3.91	$3.77	$3.49	$3.36	$3.92	$3.49
2019	$3.99	$3.84	$3.56	$3.42	$4.00	$3.56
2020	$4.07	$3.92	$3.63	$3.49	$4.08	$3.63
2021	$4.17	$4.02	$3.72	$3.58	$4.18	$3.72
2022	$4.37	$4.21	$3.90	$3.75	$4.38	$3.90
2023	$4.55	$4.38	$4.06	$3.90	$4.56	$4.06
2024	$4.66	$4.49	$4.16	$4.00	$4.67	$4.16
2025	$4.73	$4.55	$4.22	$4.05	$4.74	$4.22
2026	$4.87	$4.69	$4.35	$4.18	$4.88	$4.35
2027	$4.92	$4.74	$4.39	$4.22	$4.93	$4.39
2028	$5.05	$4.86	$4.50	$4.33	$5.06	$4.50
2029	$5.12	$4.93	$4.56	$4.39	$5.13	$4.56
2030	$5.21	$5.02	$4.64	$4.46	$5.22	$4.64
2031	$5.33	$5.13	$4.75	$4.57	$5.34	$4.75
2032	$5.42	$5.22	$4.83	$4.65	$5.43	$4.83
2033	$5.55	$5.35	$4.95	$4.76	$5.56	$4.95
2034	$5.79	$5.57	$5.16	$4.96	$5.80	$5.16
2035	$6.05	$5.83	$5.40	$5.19	$6.07	$5.40
2036	$6.43	$6.19	$5.73	$5.51	$6.44	$5.73
2037	$6.77	$6.53	$6.04	$5.81	$6.79	$6.04
2038	$7.16	$6.89	$6.38	$6.14	$7.17	$6.38
2039	$7.30	$7.03	$6.51	$6.26	$7.32	$6.51
2040	$7.52	$7.25	$6.71	$6.45	$7.54	$6.71
2041	$7.86	$7.57	$7.01	$6.74	$7.87	$7.01
2042	$8.20	$7.90	$7.32	$7.03	$8.22	$7.32
2043	$8.57	$8.25	$7.64	$7.35	$8.59	$7.64
2044	$8.95	$8.62	$7.98	$7.67	$8.97	$7.98
2045	$9.35	$9.00	$8.34	$8.01	$9.37	$8.34
2046	$9.76	$9.40	$8.71	$8.37	$9.78	$8.71
2047	$10.19	$9.82	$9.09	$8.74	$10.22	$9.09
2048	$10.65	$10.25	$9.50	$9.13	$10.67	$9.50
2049	$11.12	$10.71	$9.92	$9.53	$11.14	$9.92
2050	$11.61	$11.19	$10.36	$9.96	$11.64	$10.36
Source: U.S. EPA Analysis, 2013: U.S. DOE, 2011a; U.S. DOE, 2012c; U.S. DOE, 2012a; and U.S. DOE, 2012b						

Table A.2-3: Basin Specific Price Projections for the Low Price Growth Case (CAGR of 3.0%)

Year	APP (VA, WV, PA, OH)	BW and Cahaba (AL)	GR (WY, CO)	PRB (MT, WY)	Raton (CO, NM)	Illinois (IL, IN)
2010	$4.63	$4.46	$4.13	$3.97	$4.64	$4.13
2011	$4.19	$4.04	$3.74	$3.59	$4.20	$3.74
2012	$2.61	$2.51	$2.33	$2.24	$2.61	$2.33
2013	$3.07	$2.95	$2.73	$2.63	$3.07	$2.73
2014	$2.83	$2.73	$2.53	$2.43	$2.84	$2.53
2015	$2.79	$2.68	$2.49	$2.39	$2.79	$2.49
2016	$3.24	$3.12	$2.89	$2.78	$3.25	$2.89
2017	$3.36	$3.23	$2.99	$2.88	$3.36	$2.99
2018	$3.65	$3.51	$3.25	$3.13	$3.65	$3.25
2019	$3.70	$3.57	$3.30	$3.17	$3.71	$3.30
2020	$3.77	$3.63	$3.36	$3.23	$3.78	$3.36
2021	$3.85	$3.70	$3.43	$3.30	$3.85	$3.43
2022	$4.02	$3.88	$3.59	$3.45	$4.03	$3.59
2023	$4.16	$4.01	$3.71	$3.57	$4.17	$3.71
2024	$4.27	$4.11	$3.81	$3.66	$4.28	$3.81
2025	$4.29	$4.13	$3.83	$3.68	$4.30	$3.83
2026	$4.39	$4.23	$3.92	$3.77	$4.40	$3.92
2027	$4.45	$4.28	$3.97	$3.81	$4.46	$3.97
2028	$4.55	$4.38	$4.06	$3.90	$4.56	$4.06
2029	$4.58	$4.41	$4.09	$3.93	$4.59	$4.09
2030	$4.67	$4.50	$4.17	$4.01	$4.68	$4.17
2031	$4.77	$4.60	$4.26	$4.09	$4.78	$4.26
2032	$4.83	$4.65	$4.31	$4.14	$4.84	$4.31
2033	$5.03	$4.84	$4.48	$4.31	$5.04	$4.48
2034	$5.16	$4.97	$4.60	$4.43	$5.17	$4.60
2035	$5.46	$5.26	$4.87	$4.68	$5.47	$4.87
2036	$5.82	$5.61	$5.19	$4.99	$5.84	$5.19
2037	$6.16	$5.93	$5.50	$5.28	$6.17	$5.50
2038	$6.53	$6.29	$5.82	$5.60	$6.54	$5.82
2039	$6.66	$6.42	$5.94	$5.71	$6.68	$5.94
2040	$6.87	$6.62	$6.13	$5.89	$6.89	$6.13
2041	$7.19	$6.93	$6.42	$6.17	$7.21	$6.42
2042	$7.53	$7.25	$6.72	$6.46	$7.55	$6.72
2043	$7.88	$7.60	$7.03	$6.76	$7.90	$7.03
2044	$8.25	$7.95	$7.36	$7.08	$8.27	$7.36
2045	$8.64	$8.32	$7.71	$7.41	$8.66	$7.71
2046	$9.05	$8.72	$8.07	$7.76	$9.07	$8.07
2047	$9.47	$9.12	$8.45	$8.12	$9.49	$8.45
2048	$9.92	$9.55	$8.85	$8.50	$9.94	$8.85
2049	$10.38	$10.00	$9.26	$8.90	$10.41	$9.26
2050	$10.87	$10.47	$9.70	$9.32	$10.89	$9.70

Source: U.S. EPA Analysis, 2013; U.S. DOE, 2011a; U.S. DOE, 2012c; U.S. DOE, 2012a; and U.S. DOE, 2012b

Table A.2-4: Basin Specific Price Projections for the High Price Growth Case (CAGR of 3.4%)						
Year	**APP (VA, WV, PA, OH)**	**BW and Cahaba (AL)**	**GR (WY, CO)**	**PRB (MT, WY)**	**Raton (CO, NM)**	**Illinois (IL, IN)**
2010	$4.63	$4.46	$4.13	$3.97	$4.64	$4.13
2011	$4.19	$4.04	$3.74	$3.59	$4.20	$3.74
2012	$2.64	$2.55	$2.36	$2.27	$2.65	$2.36
2013	$3.21	$3.09	$2.86	$2.75	$3.22	$2.86
2014	$3.03	$2.92	$2.70	$2.60	$3.04	$2.70
2015	$3.05	$2.94	$2.72	$2.62	$3.06	$2.72
2016	$3.61	$3.48	$3.22	$3.10	$3.62	$3.22
2017	$3.76	$3.62	$3.35	$3.22	$3.77	$3.35
2018	$4.08	$3.93	$3.64	$3.50	$4.09	$3.64
2019	$4.19	$4.04	$3.74	$3.59	$4.20	$3.74
2020	$4.33	$4.17	$3.86	$3.71	$4.33	$3.86
2021	$4.46	$4.30	$3.98	$3.82	$4.47	$3.98
2022	$4.67	$4.50	$4.17	$4.01	$4.68	$4.17
2023	$4.91	$4.73	$4.38	$4.21	$4.92	$4.38
2024	$5.03	$4.84	$4.48	$4.31	$5.04	$4.48
2025	$5.15	$4.96	$4.59	$4.42	$5.16	$4.59
2026	$5.37	$5.18	$4.79	$4.61	$5.39	$4.79
2027	$5.40	$5.20	$4.81	$4.63	$5.41	$4.81
2028	$5.55	$5.35	$4.95	$4.76	$5.56	$4.95
2029	$5.60	$5.39	$4.99	$4.80	$5.61	$4.99
2030	$5.70	$5.49	$5.08	$4.88	$5.71	$5.08
2031	$5.84	$5.63	$5.21	$5.01	$5.85	$5.21
2032	$5.89	$5.67	$5.25	$5.05	$5.90	$5.25
2033	$6.13	$5.91	$5.47	$5.26	$6.14	$5.47
2034	$6.38	$6.14	$5.69	$5.47	$6.39	$5.69
2035	$6.56	$6.32	$5.86	$5.63	$6.58	$5.86
2036	$6.93	$6.68	$6.18	$5.94	$6.95	$6.18
2037	$7.28	$7.01	$6.49	$6.24	$7.29	$6.49
2038	$7.65	$7.37	$6.83	$6.56	$7.67	$6.83
2039	$7.79	$7.50	$6.95	$6.68	$7.81	$6.95
2040	$8.01	$7.71	$7.14	$6.86	$8.02	$7.14
2041	$8.33	$8.02	$7.43	$7.14	$8.35	$7.43
2042	$8.67	$8.35	$7.73	$7.43	$8.69	$7.73
2043	$9.02	$8.69	$8.04	$7.73	$9.04	$8.04
2044	$9.38	$9.04	$8.37	$8.05	$9.40	$8.37
2045	$9.76	$9.40	$8.71	$8.37	$9.78	$8.71
2046	$10.16	$9.79	$9.06	$8.71	$10.18	$9.06
2047	$10.57	$10.18	$9.43	$9.06	$10.59	$9.43
2048	$11.00	$10.59	$9.81	$9.43	$11.02	$9.81
2049	$11.44	$11.02	$10.21	$9.81	$11.47	$10.21
2050	$11.91	$11.47	$10.62	$10.21	$11.93	$10.62
Source: U.S. EPA Analysis, 2013; U.S. DOE, 2011a; U.S. DOE, 2012c; U.S. DOE, 2012a; and U.S. DOE, 2012b						

A.3 Uncertainties and Limitations

While EIA's price projections are inherently uncertain, EPA made a number of assumptions in adjusting prices that increases this uncertainty:

- EPA extended the AEO 2012 price projections by five years, to 2040, so that these price forecasts would cover the same period as the AEO 2013 Early Release price forecast. EPA also extended the adjusted AEO 2013 Early Release price paths 10 years, to 2050, to be used in the impact analyses. In both cases, EPA assumed that prices would grow at constant year-over-year percentage growth rates, based on the last five years of the available forecasts, following the end of the explicit forecast period.
- In creating the High and Low Price Growth cases – based on EIA's Low Economic Growth and High Economic Growth – EPA based its analysis on the Reference price projections from AEO 2013 Early Release. EPA assumed that the two alternative EIA price cases would deviate from the Reference case in the same way as they did in the AEO 2012 data. The only exception is the removal of one year of data in the High Economic Growth case, an outlier reflecting an assumption that EIA is no longer using in developing the AEO 2013 price forecasts (Joe Benneche, personal communication, December 12, 2012).
- In converting the AEO 2013 Early Release prices from Henry Hub to wellhead projections, EPA used the year-by-year price differentials from the extended AEO 2012 price paths.
- For the AEO 2013 Early Release data, EIA reports price projections at only the national level.
    - To establish projections that are more consistent with those that new CBM projects could expect to receive, EPA calculated basin-specific projections, averaging prices over the states in which a basin is located, with the assumption that future annual price changes for each state would mirror changes at the national level.
    - To develop project-specific projections for existing projects, EPA assumed that the future changes in price experienced by each project would mirror the national-level price projection.

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