

## 4.0 CUMULATIVE ANALYSES

Chapter 4 summarizes existing conditions and cumulative impacts in the PRB<sup>1</sup>, as well as projected changes to those cumulative impacts that could result from adding future developments in the area. Cumulative impacts result from the incremental impacts of an action added to other past, present, and reasonably foreseeable future actions, regardless of who is responsible for such actions. Cumulative impacts can result from individually minor, but collectively significant, actions occurring over time.

The table (table 4-41) presented at the end of this chapter provides a summary of the magnitude and duration of cumulative impacts in the PRB based on upper and lower estimates for future coal production in the region, as described in the following discussion. The Proposed Action and alternatives for the Hay Creek II EIS fall within those projections.

The BLM completed three regional EISs evaluating the potential cumulative impacts of surface coal development in the 1970s and early 1980s (BLM 1974, 1979, and 1981). A draft document for a fourth regional EIS was prepared and released in 1984 (BLM 1984). Since those regional EISs were prepared, BLM has prepared a number of NEPA analyses evaluating coal leasing actions and oil and gas development in the PRB. Each of these NEPA analyses includes an analysis of cumulative impacts in the Wyoming PRB.

The BLM is currently completing the final phases of a regional technical study, called the PRB Coal Review, to help evaluate the cumulative impacts of coal and other mineral development in the PRB. The PRB Coal Review consists of three tasks:

- Task 1 identifies existing resource conditions in the PRB for the baseline year (2003) and, for applicable resources, updates the BLM's 1996 status check for coal development in the PRB.
- Task 2 defines the past and present development activities in the PRB and their associated development levels as of 2003 and develops a forecast of reasonably foreseeable development in the PRB through 2020. The reasonably foreseeable activities fall into three broad categories: coal development (coal mine and coal-related), oil and gas development (conventional oil and gas, CBNG, and major transportation pipelines), and other development, which includes development that is not energy-related as well as other energy-related development.
- Task 3 predicts the cumulative impacts that could be expected to occur to air, water, socioeconomic, and other resources if the development occurs as projected in the forecast developed under Task 2.

A series of reports have been prepared to present the results of the PRB Coal Review task studies. The Task 1, 2, and 3 reports represent components of a technical study of cumulative development in the PRB; they do not evaluate specific proposed projects, but they provide information that BLM is using to evaluate the cumulative impacts that would be expected to occur if specific projects or applications, such as the Proposed Action, are approved. The contents and completion dates of the various task reports include:

- Task 1A Report (BLM 2005a): existing air quality conditions;

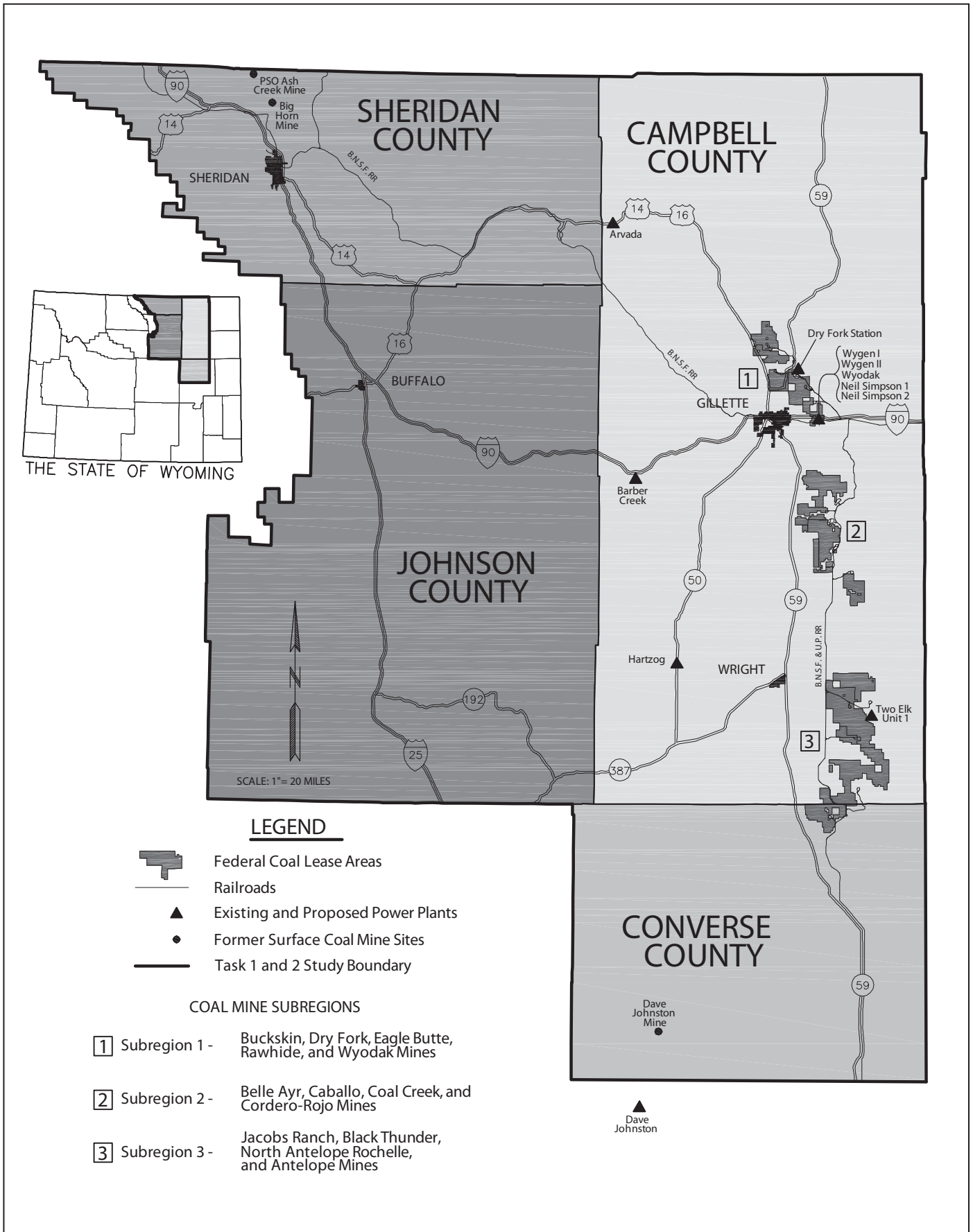
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<sup>1</sup> Refer to page xx for a list of abbreviations and acronyms used in this document.

- Task 1B Report (BLM 2006c) and update to the Task 1B Report (BLM 2009e): existing water resources conditions;
- Task 1C Report (BLM 2005b): existing social/economic conditions;
- Task 1D Report (BLM 2005c): existing other environmental resource conditions;
- Task 2 Report (BLM 2005d) and update to the Task 2 Report (BLM 2009c): past and present coal, oil and gas, and other development;
- Task 3A Report (BLM 2006d) and updates to the Task 3A Report (BLM 2008a, BLM 2009d): predicted air quality conditions;
- Task 3B Report (BLM 2006e) and update to the Task 3B Report (BLM 2009f): predicted water resources conditions;
- Task 3B Phase 2 evaluation (BLM, in progress): predicted water resource conditions;
- Task 3C Report (BLM 2005e): predicted social/economic conditions; and
- Task 3D Report (BLM 2005f) and update to the Task 3D Report (BLM 2009g): predicted other resource conditions.

The Task 1 and Task 2 reports have been completed. The update to the Task 2 Report (BLM 2009c) is reflected in this document. The Task 3 reports for air quality conditions, water resources conditions, social/economic conditions, and other resource conditions have also been completed. Information from the 2008 update to the Task 3A Report (BLM 2008a) was included in the Hay Creek II LBA draft EIS to project air quality effects for 2015. After the draft EIS was issued, modeling of cumulative air quality effects for 2020 was completed (BLM 2009c); data and analyses for both model years are reflected in this final EIS. The groundwater impacts modeling portion of the Cumulative Water Resources Effects (BLM 2009e) was recently completed and is also reflected in this document, along with the cumulative surface water effects. The Task 3B Phase 2 evaluation of water resource conditions is in progress. The information in these reports is summarized later in this chapter, and the completed reports are available for viewing at the BLM offices in Casper and Cheyenne and on the Wyoming BLM at: [http://www.blm.gov/wy/st/en/programs/energy/Coal\\_Resources/PRB\\_Coal/prbdocs.html](http://www.blm.gov/wy/st/en/programs/energy/Coal_Resources/PRB_Coal/prbdocs.html).

The PRB includes portions of northeastern Wyoming and southeastern Montana. The Wyoming portion of the PRB is the primary focus of the PRB Coal Review reports. The Montana portion of the PRB is included in the Task 2 Report and in the Task 1 and 3 air resources studies. For the majority of resources in the Task 1 reports and for the Task 2 Report, the Wyoming portion of the PRB Coal Review study area encompasses all of Campbell County, all of Sheridan and Johnson counties outside of the Bighorn National Forest, and the northern portion of Converse County (map 4-1).



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**Map 4-1**  
**Wyoming Study Area for PRB Coal Review Studies Evaluating Current and Projected Levels of Development**

For some components of the Task 2 Report and for the Task 1 and 3 air resource studies, the Montana PRB Coal Review study area includes portions of Big Horn, Custer, Powder River, Rosebud, and Treasure counties. For several resources, the Task 1 and Task 3 study areas include only potentially affected portions of the Wyoming PRB Coal Review study area; for other resources, the study area extends outside of Wyoming and Montana because the impacts would extend beyond the PRB. For example, the groundwater drawdown is evaluated in the area surrounding and extending west of the mines within the PRB, because that is the area where surface coal mining operations and CBNG production operations would affect groundwater resources; but air quality impacts are evaluated over a multi-state area, because they would be expected to extend beyond the PRB.

Section 4.1 summarizes analyses of past, present, and future levels of development presented in the Task 1 and Task 2 reports. Section 4.2 summarizes the predicted cumulative impacts on air, water, socioeconomic, and other resources presented in the Task 3 reports.

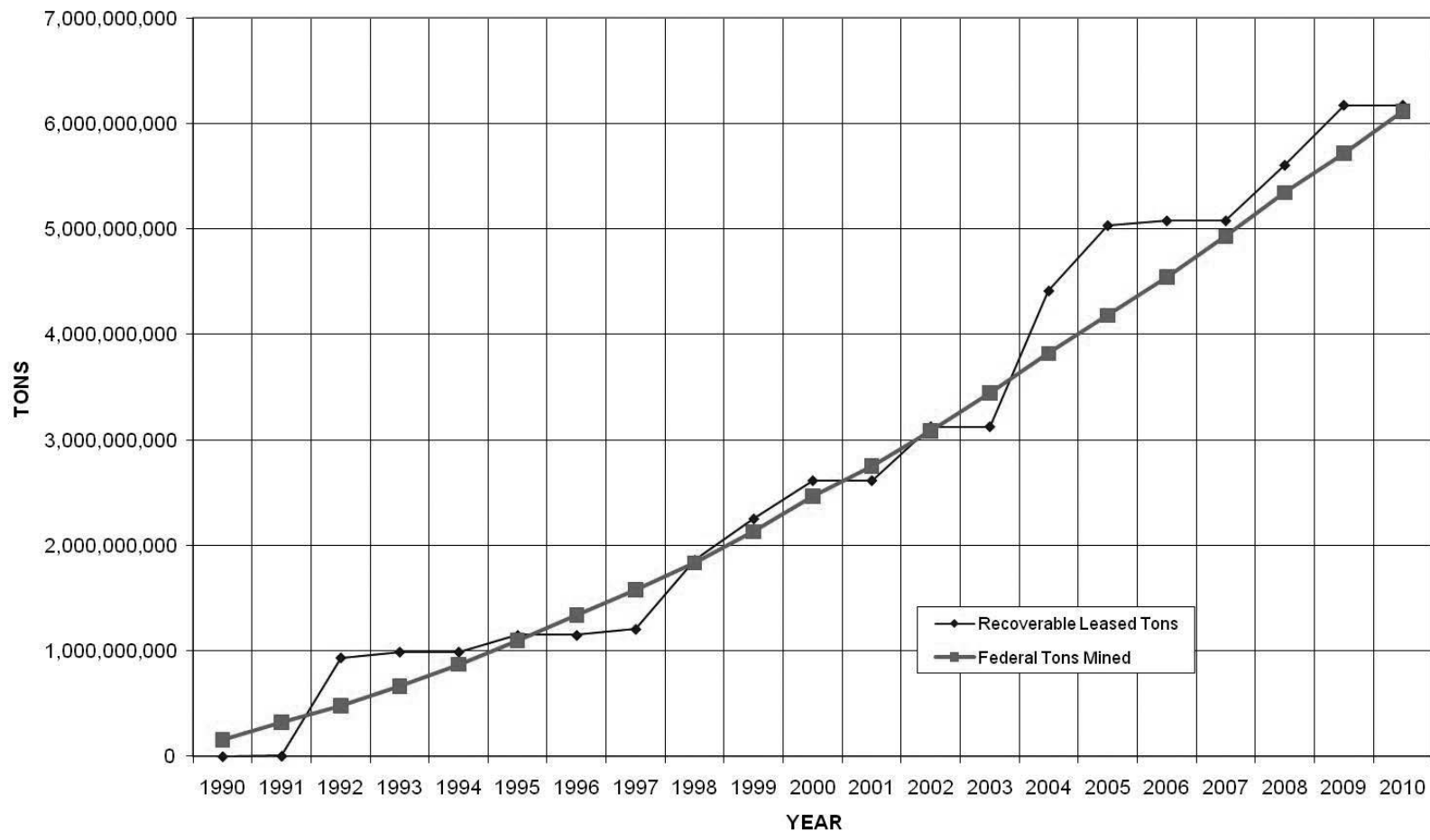
## **4.1 Past, Present, and Reasonably Foreseeable Development**

Past, present, and reasonably foreseeable development in the Wyoming PRB are considered in the Task 1 and Task 2 reports. The Task 1 reports describe the existing situation as of the end of 2003, which reflects the past and present levels of development. The Task 2 Report defines the past and present development activities in the PRB as of the end of 2003 and projects reasonably foreseeable development in the Wyoming PRB through 2020. Task 2 was updated based on actual levels of development through 2007, and current development estimates available through 2009 (BLM 2009c).

### **4.1.1 Coal Development**

#### **4.1.1.1 Coal Mine Development**

The Powder River Federal Coal Region was decertified as a federal coal production region by the PRRCT in 1990. Decertification of the region allows leasing to take place on an application basis, as discussed in the regulations at 43 CFR 3425.1-5. Between 1990 and July 2010, the BLM's Wyoming State Office held 28 competitive coal lease sales and issued 20 new federal coal leases containing almost 5.7 billion tons of coal using the LBA process. The lease sales are listed in chapter 1, table 1-1, and the leased tracts are shown on map 1-1. This leasing process has undergone the scrutiny of two appeals to the Interior Board of Land Appeals and one audit by the General Accounting Office. As can be seen on figure 4-1, leasing activity has generally paralleled production since decertification. This is consistent with the PRRCT's objective at the time of decertification, which was to use the LBA process to lease tracts of federal coal to maintain production at existing mines. The pending applications in the Wyoming PRB are listed in table 1-2.



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Figure 4-1  
 Recoverable Tons of Federal Coal Leased Versus Tons of Federal Coal Mined Since 1990 in Campbell and Converse Counties, Wyoming

The BLM has also completed three exchanges involving federal coal resources in the Wyoming PRB since decertification.

- Belco Exchange—an exchange of lease rights for a portion of the former Hay Creek federal coal tract for lease rights to coal near Buffalo, Wyoming, which became unmineable when Interstate 90 (I-90) was constructed. This exchange was authorized by Public Law 95-554 and completed in 2000.
- Pittsburg and Midway Coal Mining Company (P&M) Exchange—an exchange of federal coal in Sheridan County, Wyoming, for land and mineral rights in Lincoln, Carbon, and Sheridan counties, Wyoming, completed in 2004.
- Powder River Coal Company Alluvial Valley Floor Exchange—an exchange of lease rights underlying an AVF at the Caballo Mine, which cannot be mined, for lease rights of equal value adjacent to existing federal leases at Powder River Coal Company's North Antelope Rochelle Mine, completed in 2006.

Table 4-1 provides information about the status, ownership and production levels for the existing surface coal mines in the Wyoming PRB in 2003 and their status as of 2007. In 2003, the baseline year for the Task 1 and Task 2 studies, there were 12 active surface coal mines and one inactive mine. Since 2003, the inactive mine (Coal Creek) has resumed operations and the North Rochelle Mine has been incorporated into the Black Thunder Mine following its purchase by the operator of the Black Thunder Mine. The North Rochelle Mine leases were divided between Black Thunder and North Antelope Rochelle mines in 2006. Peabody has deferred startup of their new mine, the School Creek Mine which is located between the Black Thunder and North Antelope Rochelle Mine, until at least late 2010, or later. These mines are all located in Campbell and Converse counties, just west of the outcrop of the Wyodak coal, where the coal is at the shallowest depth (map 1-1). As indicated in table 4-1, there have been numerous changes in mine ownership since decertification, which have resulted in mine consolidations and mine closings within the PRB.

Two recently active surface coal mines (the Big Horn Coal Mine in northern Sheridan County and the Dave Johnston Mine in southern Converse County) in the PRB have ended mining operations, relinquished their federal coal leases, and reclaimed areas of disturbance.

The lands within the Dave Johnston Mine permit boundary are owned by PacifiCorp. PacifiCorp requested a change in postmining land use from livestock/wildlife grazing to industrial for the areas that would be affected by a wind energy project right-of-way. Some of the area was on full reclamation bond release and some area included was on pre-law lands. The WDEQ approved this change of land use in three stages between September 2007 and May 2008. The Glenrock Wind Energy Project is sited at the reclaimed surface coal mine and; it began operations in late 2008 and early 2009.

Other operations related to surface coal mining have existing permits in the PRB. These include the Ash Creek and Welch Mine permits in Sheridan County and the Izita Mine permit in Campbell County. Operations at these sites are completed and the disturbed areas have been reclaimed. Nevertheless, the WDEQ continues to monitor all three mines with field inspections; groundwater monitoring is also conducted at the Ash Creek Mine. The KFx Mine, located north of Gillette on privately owned coal, has stopped mining coal for processing at the KFx coal enhancement plant, which is discussed later in this chapter.

Table 4-1. Status and Ownership of Wyoming PRB Coal Mines for 2003, the PRB Coal Review Baseline Year, and for 2007

2003 Mine	1994 Mine Owner	2007 Mine Owner	2007 Coal Production (million tons) <sup>a</sup>	Permitted Production Level (million tons) <sup>b</sup>	Status and Additional Comments
Subregion 1 (North Gillette)					
Buckskin	SMC (Zeigler)	Kiewit Mining Properties, Inc.	25.3	42.0	Active
Dry Fork	Phillips/WFA & Fort Union Ltd	WFA	5.3	15.0	Active (includes former Fort Union Mine)
Eagle Butte	Cyprus-Amax	Foundation Coal West, Inc. <sup>c</sup>	25.0	35.0	Active
Rawhide	Carter (Exxon)	Peabody Holding Co.	17.1	24.0	Active
Wyodak	Wyodak Resources	Wyodak Resources	5.0	12.0	Active (includes former Clovis Point Mine)
Total			77.7	128.0	
Subregion 2 (South Gillette)					
Belle Ayr	Cyprus-Amax	Foundation Coal West, Inc.	26.6	45.0	Active
Caballo	Carter (Exxon) & Western Energy	Peabody Holding Co.	31.2	50.0	Active (includes Rocky Butte and West Rocky Butte leases)
Cordero Rojo	Kennecott & Drummond	Rio Tinto Energy America <sup>d</sup>	40.5	65.0	Active (consolidation of former Cordero and Caballo Rojo Mines)
Coal Creek	ARCO	Arch Coal Inc.	10.2	25.0	Inactive 2000, operations resumed in May 2006
Total			108.5	185.0	
Subregion 3 (Wright)					
Antelope	Kennecott	Rio Tinto Energy America <sup>d</sup>	34.5	36.0	Active
Black Thunder	ARCO	Arch Coal Inc.	65.3	100.0	Active
Jacobs Ranch	Kerr-McGee	Rio Tinto Energy America <sup>d</sup>	38.1	55.0	Active
North Antelope Rochelle	Peabody	Peabody Holding Co.	91.5	99.0	Active (consolidation of former North Antelope and Rochelle Mines)
North Rochelle	SMC (Zeigler)	Arch Coal Inc.	20.9	35.0	Inactive since 2005, leases split between Black Thunder and North Antelope Rochelle Mines
Total			250.3	325.0	
Total for 3 Subregions			436.5	638.0	

<sup>a</sup> Wyoming State Inspector of Mines (2007) and Shamley pers. comm.

<sup>b</sup> WDEQ 2007 permitting levels (Shamley pers. comm.)

<sup>c</sup> Ownership of the Eagle Butte Mine and Belle Ayr Mine changed from Foundation Coal West, Inc., to Alpha Coal West, Inc. as of July 31, 2009. Notification of new ownership was submitted to the BLM in August 2009.

<sup>d</sup> Kennecott Energy Company changed its name to Rio Tinto Energy America in 2006 and to Cloud Peak Energy Resources LLC in 2009.

In March 2008, the Fort Union plant was idled down. In August 2010, Evergreen Energy Inc. agreed to sell the Fort Union site to Synthetic Fuels LLC of Colorado, which has plans to develop a coal-to-liquids facility on the site (MarketWatch, Inc. 2010).

The active mines in the Wyoming PRB are geographically grouped into three subregions (map 4-1) for purposes of this cumulative impact discussion: 1) North Gillette; 2) South Gillette; and 3) Wright. Table 4-1 lists the mines included in each subregion.

A fourth subregion includes former and proposed mines in Sheridan County, and existing mines just north of Sheridan County, in Montana. There are currently no active mines in the Wyoming portion of the fourth subregion. However, the 2005 Task 2 Report (BLM 2005b) projected that a new mine would be developed near Sheridan by 2010. In April 2007, P&M and CONSOL Energy Inc. announced that they had formed a new company, Youngs Creek Mining Company, LLC, and entered into a joint agreement to develop a new mine in Wyoming north of Sheridan (Reuters 2007). According to the announcement, engineering, environmental, and permitting work are in progress, but actual mine construction will not start until the joint venture has enough coal sales under contract to justify the investment. The coal reserves included in this project are all privately owned (Shewski 2007).

The surface coal mines listed in table 4-1 currently produce over 96% of the coal produced in Wyoming each year. Since 1989, coal production in the PRB has increased by an average of 6% per year. The increasing production is primarily because of increasing sales of low-sulfur, low-cost PRB coal to electric utilities who must comply with the phase I requirements of Title III of the 1990 CAA Amendments. Electric utilities account for 97% of Wyoming's coal sales. In 2009, production from the Wyoming PRB coal mines dropped by about 7% from the 2008 levels, the first drop since the early 1900s. This drop coincided with a national coal production decline resulting from reduced industrial electric demand in 2009.

In 2003, the baseline year for the PRB Coal Review, more than 35% of the coal mined in the United States came from the Wyoming PRB. According to the DOE, that amount had increased to about 38% by 2007 and to over 38% by 2009 (U.S. Energy Information Administration 2009a and 2009b).

The BLM estimates that the surface coal mines listed in table 4-1 currently have about 125,180 acres of federal coal leased in Campbell and Converse counties. This represents approximately 4.1% of Campbell County, where the majority of the leases are located.

Both the 2005 and updated 2009 Task 2 reports projected coal development into the future for the years 2010, 2015, and 2020. Due to the variables associated with future coal production, two projected coal production scenarios (representing an upper and a lower production level) were developed to bracket the most likely foreseeable regional coal production level. The basis for the projected production levels included:

- analysis of historic PRB production levels in comparison to the gross domestic product and national coal demand;
- analysis of PRB coal market forecasts that model the impact of gross domestic product growth, potential regulatory changes affecting coal-fired power plants, and mining and transportation costs on PRB coal demand;

- availability, projected production cost, and quality of future mine-specific coal reserves within the PRB region; and
- availability of adequate infrastructure for coal transportation.

The projected upper and lower production levels subsequently were allocated to the Wyoming PRB subregions, discussed above, and to individual mines based on past market shares. Individual mine production levels were reviewed relative to potential future production constraints (e.g., loadout capacities), permitted production levels, mining costs, and coal quality. Then the projected future production was aggregated on a subregion basis. The actual 2003 and 2005 production levels and the two projected coal production scenarios for those years are shown in figure 4-2 and tables 4-2 and 4-3. The actual 2007 and 2008 production levels are also shown on figure 4-2 for reference.

Tables 4-2 and 4-3 show the cumulative coal mining disturbance as of the baseline year and the cumulative coal mine disturbance projected for the future years for the upper and lower coal production scenarios.

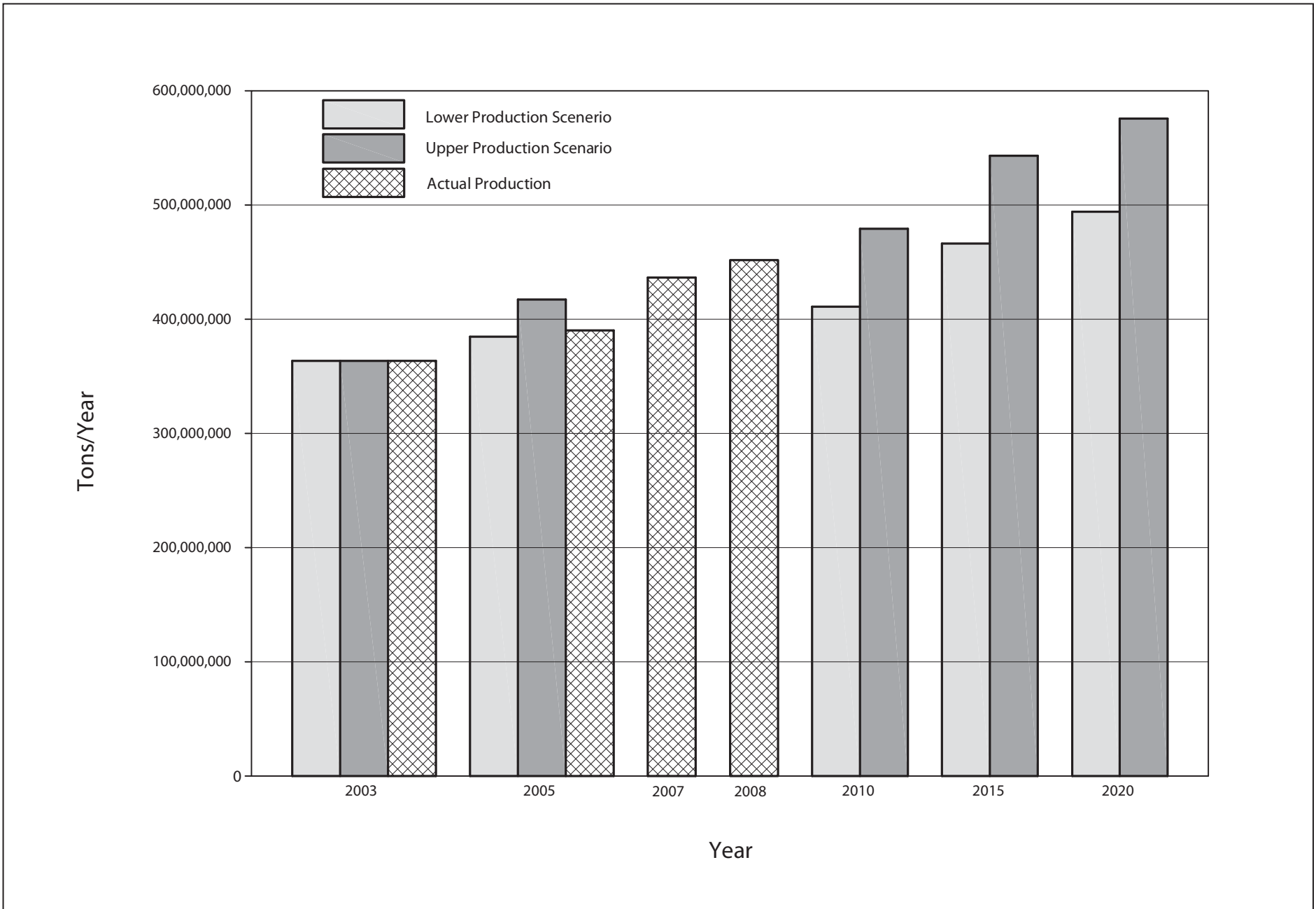
In these tables, the baseline year (2003), actual values as of 2007, and cumulative projected disturbance areas for 2010, 2015, and 2020 are broken down into three categories:

- areas that are or that are projected to be permanently reclaimed;
- areas that are or that are projected to be undergoing active mining or that have been mined but are not yet reclaimed; and
- areas that are or that are projected to be occupied by mine facilities, haul roads, stockpiles, and other long-term structures, and that are, therefore, unavailable for reclamation until mining operations are completed.

Tables 4-2 and 4-3 also include estimates of baseline year and projected future coal mining employment, water consumption, and water production.

The Hay Creek II LBA is associated with the Buckskin Mine in the North Gillette subregion of mines. The analysis assumes that if the proposed tract or an alternative tract configuration is offered and if the applicant becomes the lessee, the mine will increase current production to a level where the five mines collectively will produce at an aggregate production level midway between the low and high projected coal production scenarios for 2015 and 2020 shown in figure 4-2 and tables 4-2 and 4-3; Kiewit does not anticipate an actual increase in average annual production as a result of acquiring a new maintenance tract. The existing and projected coal development levels and associated disturbance shown in tables 4-2 and 4-3 include production at the five North Gillette area mines during the baseline year (2003) and projected production at the mines for 2010, 2015, and 2020.

As discussed above, the projected development levels shown in tables 4-2 and 4-3 are based on projected demand and coal market forecasts, which are not affected by a decision to lease or not to lease the proposed tract or alternative tract configuration. If the Proposed Action or Alternative 2 is implemented, mining of the federal coal reserves would extend the current Buckskin Mine life-of-mine estimate by two years or up to six years, respectively.



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Figure 4-2  
 Projected and Actual Total Coal Production from Campbell and Converse Counties under the Lower and Upper Production Scenarios

Table 4-2. Actual and Projected Wyoming PRB Coal Mine Development, Lower Coal Production Scenario

Subregion	Annual Production (million tons)	Cumulative Disturbed Area (acres)	Cumulative Permanently Reclaimed Area (acres)	Cumulative Active Mining Area and Unreclaimed Mined Area (acres)	Cumulative Area Disturbed and Unavailable for Reclamation <sup>a</sup> (acres)	Total Mine Employment	Annual Water Consumption (mmgpy)	Annual Water Production (acre-feet)
Original Baseline Year (2003)								
North Gillette Subregion	55	12,047	3,054	3,360	5,633	746	387	191
South Gillette Subregion	77	21,249	6,783	6,107	8,359	861	544	447
Wright Subregion	232	35,498	11,401	13,992	10,105	3,090	1,709	748
Total for 2003	364	68,794	21,238	23,459	24,097	4,697	2,640	1,386
Actual 2007								
North Gillette Subregion	78	14,421	3,658	8,342	5,781	1,032	351	191
South Gillette Subregion	100	23,630	6,441	12,353	9,273	1,424	544	447
Wright Subregion	250	45,542	15,785	31,577	11,941	3,077	1,709	748
Total for 2007	428	83,593	25,884	52,272	24,338	5,533	2,604	1,386
Reasonably Foreseeable Development for 2010								
North Gillette Subregion	62	15,231	5,004	3,968	6,260	787	628	165
South Gillette Subregion	95	28,021	12,183	6,830	9,008	1,323	50	675
Wright Subregion	254	55,410	27,751	16,588	11,070	3,153	1,115	1,419
Total for 2010	411	98,662	44,938	27,386	26,338	5,263	1,793	2,258
Reasonably Foreseeable Development for 2015								
North Gillette Subregion	74	17,457	6,654	4,202	6,601	830	724	165
South Gillette Subregion	112	32,356	15,683	7,314	9,359	1,369	458	675
Wright Subregion	281	67,423	38,851	16,983	11,589	3,186	1,277	1,419
Total for 2015	467	117,236	61,188	28,499	27,549	5,405	2,059	2,258
Reasonably Foreseeable Development for 2020								
North Gillette Subregion	78	19,729	8,429	4,350	6,950	840	456	165
South Gillette Subregion	126	36,994	19,683	7,589	9,723	1,476	72	675
Wright Subregion	291	80,720	51,351	17,243	12,124	3,215	1,334	1,419
Total for 2020	495	137,443	79,463	29,182	28,797	5,531	2,162	2,258

<sup>a</sup> Area unavailable for reclamation includes disturbed areas occupied by permanent or long-term facilities such as buildings, roads, and topsoil stockpiles.

Source: Updated Task 2 Report (BLM 2009c).

#### 4.0 Cumulative Environmental Consequences

**Table 4-3. Actual and Projected Wyoming PRB Coal Mine Development, Upper Coal Production Scenario**

Subregion	Annual Production (million tons)	Cumulative Disturbed Area (acres)	Cumulative Permanently Reclaimed Area (acres)	Cumulative Active Mining Area and Unreclaimed Mined Area (acres)	Cumulative Area Disturbed and Unavailable for Reclamation <sup>a</sup> (acres)	Total Mine Employment	Annual Water Consumption (mmgpy)	Annual Water Production (acre-feet)
Original Baseline Year (2003)								
North Gillette Subregion	55	12,047	3,054	3,360	5,633	746	387	191
South Gillette Subregion	77	21,249	6,783	6,107	8,359	861	544	447
Wright Subregion	232	35,498	11,401	13,992	10,105	3,090	1,709	748
Total for 2003	364	68,794	21,238	23,459	24,097	4,697	2,640	1,386
Actual 2007								
North Gillette Subregion	78	14,421	3,658	8,342	5,781	1,032	351	191
South Gillette Subregion	100	23,630	6,441	12,353	9,273	1,424	544	447
Wright Subregion	250	45,542	15,785	31,577	11,941	3,077	1,709	748
Total for 2007	428	83,593	25,884	52,272	24,338	5,533	2,604	1,386
Reasonably Foreseeable Development for 2010								
North Gillette Subregion	78	15,911	5,404	4,217	6,290	811	788	165
South Gillette Subregion	117	29,279	13,416	7,536	8,328	1,375	58	675
Wright Subregion	284	57,258	27,951	18,236	11,070	3,153	1,184	1,419
Total for 2010	479	102,448	46,771	29,989	25,688	5,339	2,030	2,258
Reasonably Foreseeable Development for 2015								
North Gillette Subregion	104	18,490	7,329	4,500	6,660	905	492	165
South Gillette Subregion	138	35,624	18,616	8,248	8,760	1,431	75	675
Wright Subregion	301	70,431	39,451	19,391	11,589	3,186	1,333	1,419
Total for 2015	543	124,545	65,396	32,139	27,009	5,522	1,897	2,258
Reasonably Foreseeable Development for 2020								
North Gillette Subregion	121	21,311	9,529	4,766	7,013	1,019	880	165
South Gillette Subregion	148	42,981	25,016	8,758	9,206	1,444	86	675
Wright Subregion	307	84,797	51,651	21,021	12,124	3,215	1,437	1,419
Total for 2020	576	149,089	86,196	34,545	28,345	5,678	2,403	2,258

<sup>a</sup> Area unavailable for reclamation includes disturbed areas occupied by permanent or long-term facilities such as buildings, roads, and topsoil stockpiles.

Source: Updated Task 2 Report (BLM 2009c).

As discussed in sections 1.1.3.1, Kiewit estimates that the existing Buckskin Mine had approximately 344.3 million tons of recoverable coal reserves at the end of 2008. Overall, the mine had produced a total of 339.8 million tons of coal as of December 2008, with annual production averaging 20.6 million tons over the previous six years. The mine's current air quality permit as approved by the WDEQ allows mining of up to 42 million tons of coal per year. If the mine produces coal at the projected average annual estimate of 25 million tons, the remaining recoverable reserves would be depleted in less than 14 years (2022). If the mine increases production to the permitted level, the remaining recoverable reserves at the Buckskin Mine would be depleted in about 8.8 years (2016). Kiewit estimates that the proposed tract includes approximately 54.1 million tons of recoverable coal. Based on that estimate, acquisition of the proposed tract would increase the recoverable reserves at the Buckskin Mine by almost 14.6%. At the estimated future average annual production level (25 million tons), mine life would be extended by over two years. However, if production levels increase to the currently permitted level (42 million tons per year) or if the WDEQ approves a higher annual rate of production, the coal would be recovered more quickly.

#### 4.1.1.2 *Coal-Related Development*

Coal-related development as defined for this analysis includes railroads, coal-fired power plants, major (230-kilovolt [kV]) transmission lines, and coal technology projects. Table 4-4 summarizes the estimated disturbance associated with coal-related development activities for the baseline year and the projected disturbance through 2020. The subsequent paragraphs summarize the existing coal-related development in the Wyoming PRB and the reasonably foreseeable development considered in the PRB Coal Review.

**Table 4-4. Actual and Projected Wyoming PRB Coal-Related Development (acres)**

	Actual		Projected	
	2003	2007	2015	2020
	4,892	5,802	6,915	6,914

Source: Updated Task 2 Report (BLM 2009c).

#### Coal Transportation

As discussed above, electric utilities account for about 97% of Wyoming's coal sales. Most of the coal sold to electric utilities is transported to power plants by rail. A small part, about 2% in 2007, of national coal production is exported abroad, but data are not published as to where this export coal is produced. A joint BNSF and UP rail line serves the coal mines in the Wright and South Gillette subregions. For the baseline year of 2003, the existing capacity of the line was estimated at approximately 350 million tons per year. For that same year, the existing capacity of the BNSF line, which services the North Gillette subregion, was estimated at 250 million tons per year.

The PRB Coal Review projected that two coal transportation projects would be developed prior to 2020 in Wyoming: expansion of the BNSF and UP rail facilities south of Gillette and the construction of the Dakota, Minnesota and Eastern Railroad Corporation (DM&E) rail line in Wyoming and South Dakota. A third project proposed by the Tongue River Rail Company would be built between Decker and Miles City, Montana.

BNSF and UP completed work to improve sections of the existing joint rail line and had increased capacity from 350 million tons per year to 450 million tons per year by 2008 with plans to improve additional sections of the existing joint rail line and to further increase capacity to 500 million tons per year by 2012. This work includes construction of third and fourth main line track segments where needed. The increased capacity would accommodate the projected upper and lower production rates at the southern mines, which are projected to produce 439 million tons per year and 455 million tons per year by 2020. The remaining planned expansion projects are considered highly likely to occur.

The proposed DM&E rail line would include new rail construction in South Dakota and Wyoming (approximately 15 and 265 miles, respectively) and 600 miles of rail line rehabilitation in South Dakota and Minnesota. Approximately 78 miles of the new rail line construction would provide new rail services to the coal mines in the South Gillette and Wright subregions. The Surface Transportation Board released a final supplemental EIS for the DM&E project on December 30, 2005, and granted final approval to construct the rail line on February 15, 2006. The supplemental EIS, which addressed issues that were successfully appealed after an EIS was completed in 2001, was also appealed. The U.S. Court of Appeals for the Eighth Circuit upheld the appeal of the supplemental EIS in December 2006. In 2007, Canadian Pacific Railway Ltd. (CP) acquired DM&E and the Surface Transportation Board approved CP's acquisition of DM&E on September 30, 2008 (All Business 2008). The railroad's expansion into the PRB would require a substantial financial commitment, and CP is concentrating on the integration of DM&E's operation before making a decision on the expansion project. No decision has been made on whether or not CP will build the PRB extension. This decision is contingent on several conditions: 1) acquire the necessary right-of-way to build the line; 2) execute agreements with PRB mines on terms for operations by DM&E over their loading tracks and facilities; 3) secure sufficient contractual commitments from prospective coal shippers to route their traffic over the PRB line to justify the investment required to build the line; 4) arrange financing for the project; and 5) an economic and regulatory environment that would support a long-term investment of this magnitude must be present (Dakota, Minnesota & Eastern Railroad 2009).

The Surface Transportation Board announced approval of the final stretch of the rail line proposed by the Tongue River Railroad Company in October 2007. The company must acquire necessary federal and state permits and rights-of-way through private and public property before constructing the line. If it is constructed, it would provide a shorter route for some of the mines in the North Gillette subregion, which ship coal on the existing BNSF rail line (Brown 2007).

For the purposes of the PRB Coal Review, it was projected that the DM&E line would be constructed when the total rail haulage requirement from the eastern Wyoming PRB reaches 450 to 500 million tons per year and would potentially be operational by 2015. The construction of this rail line is considered moderately likely to occur. The PRB Coal Review assigned a low likelihood of development by 2010 under the upper coal production scenario, and projected the construction of the Tongue River Railroad Company line would not occur unless the Otter Creek

Mine is developed. Development of the Otter Creek tracts—more than a billion tons of state and private coal—could initiate expansion of the region’s coal industry and facilitate construction of the Tongue River Railroad. Appraisals of the Otter Creek lease tracts were completed in April 2009 (Brown 2009) and the Montana Land Board voted to lease the 572 million tons of state-owned coal in December 2009 (Dennison 2009). The Montana Board of Land Commissioners voted to approve the lease of the Otter Creek tracts to Ark Land Company on March 18, 2010 (Montana Department of Natural Resources and Conservation 2010).

### Electric Power Generation

Five coal-fired power plants are in the Wyoming PRB study area analyzed in Tasks 1 and 2 (map 4-1). Black Hills Power Corporation owns and operates the Neal Simpson Units 1 and 2 (21.7 megawatts [MW] and 80 MW, respectively), Wygen I and II (80 MW and 95 MW, respectively), and Wyodak (330 MW) power plants, all of which are located approximately 5 miles east of Gillette, Wyoming. Pacific Power and Light’s Dave Johnston Power Plant is located near Glenrock, Wyoming, outside of, but adjacent to, the study area.

Three separate interconnected gas-fired power plants (Hartzog, Arvada, and Barber Creek) are also located near Gillette, Wyoming (map 4-1). Each contains three separate 5-MW-rated turbines that provide electric power to Basin Electric and its customers. In winter, the maximum capacity can reach 22.6 MW from each site. All units are in operating condition, although they do not operate at maximum capacity.

Several additional power plants are projected to be built prior to 2020. The PRB Coal Review assumed that proposed coal-fired power plants that plan to initiate operation by 2010 would have to have been undergoing air quality permit review by 2003 in order to obtain the required construction permits and complete construction by 2010. The study identified the following four projects as likely for development by 2015.

- Black Hills Power and Light has received an air permit for the start of construction of WYGEN III; issues related to that permit currently are being resolved. WYGEN III would be a 100-MW facility located adjacent to WYGEN II. The plant is in construction and nearing completion. Operation of this facility by 2015 is considered highly likely.
- Basin Electric Power Cooperative has obtained an air construction permit for a 385-MW coal-fired power plant (Dry Fork Station) near Gillette, Wyoming. The estimated startup date is 2011. It is estimated that 1.2 million tons of coal per year would be required to fuel the facility. The cooling technology includes a dry scrubber, since that type of operation commonly is installed for PRB coal-fired units. Operation of this facility by 2015 is considered highly likely.
- North American Power Group has permitted a 280-MW coal-fired power plant (Two Elk Unit #1) at a 40-acre site located approximately 15 miles southeast of Wright, Wyoming. As originally permitted, the project also would include installation of a 45-MW gas-fired turbine. The air permit originally was issued in August 2002; construction has been initiated, with actual startup expected in 2011. This unit would be dry-cooled, requiring very little water. Campbell County approved more than \$123 million in industrial revenue bonds for application to the Two-Elk financing. Operation of this facility by 2015 is considered moderately likely.

- Wyoming Power Company (a subsidiary of NAPG) submitted a permit application for Two-Elk Unit #2. This unit would be a 750-MW supercritical pulverized coal-fired electric generating unit that would burn coal from the nearby mines. The unit would be located on an approximately 60-acre site adjacent to Two-Elk Unit #1. The permit was expected to be issued in 2008, and operation of this unit was considered moderately likely in 2015. Currently, the Wyoming Power Company (a subsidiary of NAPG) has a proposal for Two Elk Unit #2. Some paperwork for this project was filed with WDEQ. The paperwork was returned in March 2010.

The PRB Coal Review assumes that all existing power plants in the PRB region would remain operational through 2020.

#### **Transmission Lines**

Major transmission lines in the Wyoming PRB study area that support the regional distribution system are associated with the Dave Johnston Power Plant located near Glenrock, Wyoming, and the power plants operated by Black Hills Power Corporation, which are located east of Gillette. These 230-kV transmission lines have been in place for several years, and their associated permanent disturbance is minimal. Distribution power lines associated with conventional oil and gas and CBNG development also occur within the study area. For the PRB Coal Review, these lines were included by factoring them in proportionally on a per-well basis.

The PRB Coal Review estimated that by 2020 four major transmission lines would be constructed. Markets would dictate the size and location of such facilities, and these are not known as of this time. Because transmission lines are a necessary supporting infrastructure for power generating facilities to provide connection to the grid, the PRB Coal Review assumes they would be required as part of the overall system development for the proposed power plants discussed in the previous section. Six specific proposals for these transmission lines have been identified by the PRB Coal Review analysis update. Information is insufficient to analyze or assign likelihood of development by 2020.

The governors of California, Nevada, Utah, and Wyoming entered into a memorandum of understanding to encourage development of a high voltage power transmission line, the Frontier Line, connecting those states in April 2005. Since that time, no specific plans have been announced as to the location or timing of the Frontier Line. The 345-kV Wyoming-Colorado Intertie as well as the Trans West and Gateway West and South projects have been proposed in Wyoming to move power from Wyoming to growing load demands in Idaho, Nevada, and other areas in the western United States (Hodges 2007). The TransWestern Express proposes to move electric power from Wyoming to Arizona through Colorado or Utah. The High Plains Express is proposed to move power from Wyoming to New Mexico and Arizona.

An estimated 1,380 MW of new power plant production capacity and 250 MW of new wind energy production capacity are anticipated in the Task 2 study area by 2015. One new 300-MW wind energy project and potentially up to 700 MW of additional power generation provided by coal-fired power plants is projected for 2020. This level of production would require construction of additional transmission line capacity. It is assumed that new transmission lines would be constructed to connect new power plants to the grid. It is projected that these transmission lines would be constructed by 2015 to connect to outside markets. However,

specific location(s), capacities, and effects on the existing system cannot be determined at this time.

### Coal Conversion Technology

With rising energy prices, there has been considerable interest in either enhancing the quality of PRB coal and/or converting the coal to other fuels. Test facilities were previously constructed by AMAX (predecessor to Foundation Coal West, Inc. and Alpha Coal West, Inc.) at the Belle Ayr Mine, and by ENCOAL at the Buckskin Mine, but no commercial production occurred, and these facilities have either been dismantled or are no longer in use. Evergreen Energy (formerly operating as KFx) previously built a prototype commercial-scale coal upgrading plant near the old Fort Union Mine (now part of the Dry Fork Mine). The facility did achieve commercial production levels of K-Fuel® (the company's enhanced coal product) for a short period (2006 through early 2008); it was used for testing and demonstration purposes. Approximately 60 people were employed at the plant. Evergreen Energy decided to idle the plant in May 2008, laying off all but caretaker staff.

The following coal conversion projects have been proposed, and are described in some detail in the PRB Coal Review. These projects were not included in the PRB Coal Review analysis because the likelihood of their occurrence was not known when the analysis was conducted:

- *Evergreen Energy Coal Beneficiation Project.* Long-term plans for Evergreen Energy's coal upgrading plant near the Dry Fork Mine have not been announced, although reopening and dismantling the currently idle plant and redeploying some of the equipment to another location have surfaced as possibilities.
- *Rentech Inc. Coal Liquefaction Project.* In 2004, Rentech completed a feasibility study for a coal liquefaction facility, based on the historic Fischer-Tropsch process, to produce low-sulfur diesel fuel from sub-bituminous coal. Thereafter, Rentech continued to consider the potential of developing a commercial-scale facility in the PRB, while simultaneously investing in a product demonstration facility near Denver, Colorado.
- *White Energy Company, NRG Energy, and Buckskin Mining Company.* In March 2008, the three companies entered into a joint development agreement to complete a feasibility study of building and operating a plant having a capacity to produce at least 1 million tons of binderless coal briquettes annually at the Buckskin Mine. Although the plant would be located on surface owned by the Buckskin Mine, and would purchase coal from the mine, it would be permitted and operated independently from the mine by White Energy Company and NRG Energy.
- *GreatPoint Energy and Peabody Coal.* These two companies entered into an agreement in January 2008, under which Peabody Coal would become the preferred provider of coal to GreatPoint Energy for use in a commercial-scale coal-to-gas conversion plant in the PRB.
- *Wyoming Infrastructure Authority.* The Wyoming Infrastructure Authority (WIA) was created in 2004 by the Wyoming State Legislature. It was tasked with promoting the state's economic development by assisting in the development of interstate electric transmission infrastructure. In 2006, WIA's role was expanded to also promote advanced coal technologies related to electric generation (Wyoming Infrastructure Authority 2008a). In

2007, WIA selected PacifiCorp from a list of 17 candidate firms and entered into a public-private partnership to assess the feasibility of developing an integrated gasification combined cycle power plant. The initial study focused on a site in southwestern Wyoming, but may open the way for similar projects elsewhere in the state (Wyoming Infrastructure Authority 2008a), including the PRB.

- Additionally, there is a developing technology that would use existing oil and gas wells to generate biologically formed methane by enhancing the methane production from naturally occurring microbes in the coal. This process is proposed for commercial testing. It is a hybrid between conventional in-situ coal gasification and conventional CBNG development. A policy to authorize and regulate this activity is currently being developed by the Department of the Interior.

#### Carbon Sequestration

Carbon sequestration, the process of carbon capture, separation, and storage or reuse, is being researched as a means to stabilize and reduce concentrations of CO<sub>2</sub> (a GHG). Direct options for carbon sequestration would involve means to capture CO<sub>2</sub> at the source (e.g., power plant) before it enters the atmosphere coupled with “value-added” sequestration (e.g., use of captured CO<sub>2</sub> in enhanced oil recovery [EOR] operations). Indirect sequestration would involve means of integrating fossil fuel production and use with terrestrial sequestration and enhanced ocean storage of carbon.

No carbon sequestration projects currently exist in the Wyoming PRB study area. However, CO<sub>2</sub> is being injected underground for the purpose of EOR near that study area in the Salt Creek area.

The 59th Session of the Wyoming State Legislature passed, and Governor Freudenthal signed into law, legislation that could affect long-term energy-related development in the PRB (House Bills 0089 and 0090) (Wyoming Legislative Services 2008). The former (now part of Wyoming Statute 34-1) specified the ownership of subsurface “pore” space, established the rights to use such space for the purpose of carbon sequestration, and maintained the primacy of the mineral estate and the owners of such estate to reasonable use of the surface for the purpose of mineral exploration and production.

Legal provisions enacted as a result of House Bill 0090 vested regulatory control over carbon sequestration with WDEQ and directed the department to promulgate rules, regulations (including permitting processes), and standards for such use. The legislation also specifies that applications for a carbon sequestration project must describe the geology of the area, aquifers above and below the intended injection zone, drill holes and operating wells in the area, potential impacts on other fluid resources, and identify a program for detecting migration or excursion of the CO<sub>2</sub>. Finally, the enacted legislation (Wyoming Statute 35-11-103) specifically states that the act is not intended to impede or impair the rights of oil and gas operators to inject CO<sub>2</sub> through an approved EOR project and establish, verify, register, and sell emissions reduction credits.

Based on the coal-related and oil- and gas-related development in the PRB study area, the potential exists for future development of carbon sequestration in the area. However, no commercial projects specifically targeted at capturing and sequestering carbon have been

identified at this time. Sequestration was not included in the PRB Coal Review analysis because the likelihood of projects occurring was not known when the analysis was conducted.

Table 4-5 is a summary of past, present, and reasonably foreseeable coal mines, coal-related facilities, coal production, coal mine employment, and coal and coal-related disturbance in the Wyoming PRB.

**Table 4-5. Past, Present, and Projected Wyoming PRB Coal Mine and Coal-Related Development Scenario**

Year	Coal Production (million tons per year)	Number of Active Coal Mines <sup>a</sup>	Number of Active Power Plants	Number of Active Coal Conversion Facilities <sup>b</sup>	Direct Coal Mine Employment	Total Coal Disturbance (acres) <sup>c</sup>
Past and Present						
1990	163	18	3	1	2,862	N/A
1995	247	19	4	1	3,177	N/A
2000	323	12	4	2	3,335	N/A
2003	364	12	4	0	4,697	68,794
2007	428	13	5	0	5,533	83,593
Projected Development—Lower Coal Production Scenario						
2010	411	131	7	12	5,433	98,662
2015	467	131	7	12	5,705	117,236
2020	495	131	7	12	5,731	137,443
Projected Development—Upper Coal Production Scenario						
2010	479	131	7	12	5,509	102,448
2015	543	131	7	12	5,722	124,545
2020	576	131	8	12	5,998	149,089

N/A = Not Available

<sup>a</sup> Mines have consolidated and may continue to do so in the future. Also, new mines may be permitted to better access the coal reserves projected for mining by 2020.

<sup>b</sup> Several coal conversion facilities currently are being evaluated; however, there is only one for which the likelihood of future development currently can be assessed.

<sup>c</sup> Disturbance area includes coal mine and coal-related disturbance areas.

Source: Annual Report of the Wyoming State Mine Inspector (Wyoming Department of Employment 1990, 1995, 2000, 2003, and 2007a) and Updated Task 2 Report (BLM 2009c).

## 4.1.2 Oil and Gas Development

The following information on existing conventional and CBNG development is summarized from the updated Task 2 Report (BLM 2009c). The information reported is for 2003, which was the baseline year for the coal review.

### 4.1.2.1 Conventional Oil and Gas

Conventional oil and gas development includes all non-CBNG development activity. Approximately 1,500 conventional oil and gas wells, including producing, non-producing, and injection wells, were drilled between 1990 and 2003 (IHS Energy Services 2004) in the Task 2 study area. Of those, 60% were development wells drilled in established producing areas. The remaining 40% were classified as wildcat wells, which are wells that are drilled in non-producing areas or drilled to evaluate untested prospective zones in producing areas. Approximately 75% of the wildcat wells were plugged and abandoned. By 2003, the successful new field wildcat wells had resulted in the discovery of 61 new fields that produced 719,000 barrels of oil and 1.45 billion cubic feet of non-CBNG (Wyoming Oil and Gas Conservation Commission 2004).

As of the end of 2003, approximately 3,500 producing conventional oil and gas wells were in the Wyoming PRB study area plus 1,386 seasonally active wells (IHS Energy Services 2004). The WOGCC reported that these wells produced approximately 13 million barrels of oil and 41 billion cubic feet of conventional gas in 2003 (Wyoming Oil and Gas Conservation Commission 2004). The USGS (2002a) estimated that the mean undiscovered noncoal bed hydrocarbon resource in the PRB (including Montana) is 1.8 billion barrels of oil equivalent.

By the end of 2007, there were approximately 3,857 producing conventional oil and gas wells in the Wyoming PRB study area plus an estimated 1,500 seasonally active wells (IHS Energy Services 2008). WOGCC reported that these wells produced approximately 11.4 million barrels of oil and 22 billion cubic feet of conventional gas in 2007 (Wyoming Oil and Gas Conservation Commission 2008c).

Most of Wyoming's current oil production is from old oil fields with declining production, and the level of exploration drilling to discover new fields has been low (Wyoming State Geological Survey 2002). This situation is reflected in the PRB where, over the 10-year period from 1992 through 2002, oil production from conventional oil and gas wells in Campbell and Converse counties decreased approximately 60.4% (from 32.8 million barrels in 1992 to 13.0 million barrels in 2002). Oil prices have been increasing, which is reversing projections of a continuing decline in oil and gas production. Thus, production is now expected to increase in the PRB, with a peak around 2010 of approximately 15.7 million barrels (WSO-RMG 2005). Oil production in the short term may also be bolstered by some planned CO<sub>2</sub> flood projects in the PRB (Wyoming State Geological Survey 2003). This projected temporary upward trend in conventional oil and gas development is reflected in the PRB Coal Review projections (table 4-6).

Table 4-6. Actual Wyoming PRB Conventional Oil and Gas Development Scenario

Production and Wells	Actual	
	2003	2007
Annual Gas Production (billion cubic feet)	39.9	22.0
Annual Oil Production (million barrels)	12.9	11.4
Active Wells	5,067 <sup>a</sup>	3,857 <sup>b</sup>
Inactive Wells	1,994	0 <sup>c</sup>

<sup>a</sup> Total includes approximately 1,500 seasonally active wells.

<sup>b</sup> Total includes approximately 1,500 seasonally active wells and an unknown number of inactive wells.

<sup>c</sup> Unknown.

Source: Updated Task 2 Report (BLM 2009c).

The active wells identified in table 4-6 include wells that produce year-round, seasonally producing wells, and service wells (mainly injection wells). It is estimated that there are approximately 2,000 idle conventional oil and gas wells in the PRB Coal Review study area (Wyoming Oil and Gas Conservation Commission 2008). However, the number of idle wells would gradually be reduced in the future through plugging programs, and the idle well locations (once the wells are abandoned) would be reclaimed, and would no longer represent a disturbance.

#### 4.1.2.2 CBNG Development

Natural gas production has been increasing in Wyoming. In the PRB, this is because of the development of shallow CBNG resources. Commercial development of these resources began in limited areas west of and adjacent to the northernmost surface coal mines in the late 1980s. Since that time, CBNG development has spread south and west into other parts of the Task 1 and Task 2 study areas.

On private and state oil and gas leases, the WOGCC and the Wyoming State Engineer's Office (SEO) authorize CBNG drilling. On federal oil and gas leases, the BLM must analyze the individual and cumulative environmental impacts of all drilling (federal, state, and private), as required by NEPA, before CBNG drilling can be authorized. The BLM does not authorize drilling on state or private leases but must consider the impacts from those wells in their NEPA analyses. In many areas of the PRB, the coal estate is federally owned, but the oil and gas estate is privately owned. A June 7, 1999, Supreme Court decision (98-830) assigned the rights to develop CBNG on a piece of land to the owner of the oil and gas estate.

Annual CBNG production increased rapidly in the PRB between 1999 and 2003 but has leveled off somewhat since then. At the end of 2003, 14,758 producing CBNG wells were in the study area (IHS Energy Services 2004), and total production for 2003 was 346 billion cubic feet, or 88% of the total gas production from the PRB (Wyoming Oil and Gas Conservation Commission 2004). Total CBNG production in the PRB was 377 billion cubic feet for 2006, 432 billion cubic feet for 2007, and 536 billion cubic feet for 2008 (Wyoming Oil and Gas Conservation Commission 2009). Average daily CBNG production was about 947 million cubic feet per day in 2003 (Holcomb 2003), 1,033 in 2006, 1,177 in 2007, and 1,469 in 2008 (Wyoming Oil and Gas Conservation Commission 2009). From 1987 to 2003, the total cumulative gas production from PRB coals was over 1.2 trillion cubic feet. The total water production for the same period

was approximately 2.3 billion barrels (96,600 million gallons). According to the WOGCC website, water production in the PRB associated with CBNG production has ranged between just over 567 million barrels (23,814 million gallons), or about 1.6 million barrels per day, in 2003, and 679 million barrels, about 1.9 million barrels per day, since December 2003.

Since the early 1990s, the Wyoming BLM has completed numerous environmental assessments and two EISs analyzing CBNG projects. The most recent of these is the Final EIS and Proposed Plan Amendment for the PRB Oil and Gas Project, completed in January 2003 (BLM 2003). The level of CBNG development since 2003 appears to be lower than was forecast in that document. New CBNG well numbers fell from a high of slightly more than 4,600 in 2001 to approximately 2,000 in 2004. The updated Task 2 Report (BLM 2009c) discusses the uncertain trends for future CBNG activity in recent years. The methodology used to project future activity is detailed in appendix E of that report. Table 4-7 shows the baseline 2003, actual 2007, and projected 2010, 2015, and 2020 levels of CBNG development used to evaluate projected cumulative environmental impacts in the PRB Coal Review.

**Table 4-7. Actual Wyoming PRB CBNG Development Scenario**

Production and Wells	2003	2007
Annual Production (billion cubic feet)	338	432
Active Wells	14,758	20,408

Source: Updated Task 2 Report (BLM 2009c).

The amount of CBNG activity appears to be at a lower rate than was forecast by earlier projections in the Final EIS and Proposed Plan Amendment for the PRB Oil and Gas Project (BLM 2003), as well as in the 2005 Task 2 Report (BLM 2005b). New CBNG well numbers fell from a high of slightly more than 4,600 in 2001 to approximately 2,000 in 2004. It is anticipated that the number of new wells would increase so that between 2010 and 2020 the number of new wells drilled per year, basinwide, would range from 2,892 to 3,943. As shown in table 4-7, there would be 31,943 CBNG wells basinwide by 2010, considerably lower than the over 40,000 wells predicted for the same time period in the Final EIS and Proposed Plan Amendment for the PRB Oil and Gas Project (BLM 2003). It is anticipated that production in the cumulative effects study area would increase from the 432 billion cubic feet per year observed in 2007 to approximately 1,026 billion cubic feet per year in 2020. These estimates are relatively aggressive related to actual activity from 2003 to 2007 (BLM 2009c), and it is likely that the Buffalo RMP revision, currently underway, will further refine these estimates.

#### 4.1.2.3 Oil- and Gas-Related Development

Oil- and gas-related development activities considered in the PRB Coal Review include major transportation pipelines and refineries. Table 4-8 summarizes the net disturbance, reclamation, and water production associated with oil and gas activity (conventional oil and gas, CBNG, and major transportation pipelines) for 2003 (baseline year) and projects disturbance, reclamation, and water production for future years.

**Table 4-8. Wyoming PRB Conventional Oil and Gas, CBNG, and Related Development Disturbance and Water Production**

Category	Actual		Projected		
	2003	2007	2010	2015	2020
Cumulative Disturbed Area (acres) <sup>a</sup>	177,140	178,023	248,086	344,713	427,557
Cumulative Permanently Reclaimed Area (acres)	114,777	111,926	157,803	226,775	310,959
Cumulative Unreclaimed Area (acres)	62,363	66,097	90,283	117,959	116,598
Annual Water Production (million gallons per year)	26,405	31,738	50,865	71,166	72,047

<sup>a</sup> Inclusive of conventional oil and gas and CBNG activities and major transportation pipelines. Disturbance associated with ancillary facilities (including gathering lines and distribution power lines) has been factored in a per-well basis.

Source: Updated Task 2 Report (BLM 2009c).

## Pipelines

Major transportation pipelines for the transport of oil and gas to outside markets are a key factor in the development of CBNG and conventional oil and gas resources in the Task 2 study area for the Wyoming portion of the PRB. Major transportation pipelines also provide for transport of CO<sub>2</sub> to crude oil well fields, which depend somewhat on the availability of CO<sub>2</sub> for EOR.

Currently, there are more than 13 major transportation pipeline systems in the PRB that transport gas resources to markets outside of the PRB (Flores et al. 2001; Wyoming Pipeline Authority 2008). The current capacity of these pipeline systems is approximately 2.1 billion cubic feet per day. Currently, the combined natural gas production (CBNG and conventional gas) in the Wyoming PRB study area is approximately 1.22 billion cubic feet per day.

Gathering lines and power lines associated with conventional oil and gas and CBNG development also occur within the study area; disturbance from these ancillary facilities were factored into the PRB Coal Review analysis on a per-well basis.

Currently, there are two proposed natural gas transportation pipeline projects and one proposed EOR pipeline that would cross the PRB study area:

- Bison Pipeline LLC (Bison), wholly owned by a subsidiary of TransCanada Corporation, is proposing to construct the Bison Pipeline Project, an interstate natural gas pipeline designed to transport gas from the PRB to the Midwest market. The Bison project will consist of approximately 302 miles of 30-inch-diameter natural gas pipeline and related facilities that will extend from near Gillette through southeastern Montana and southwestern North Dakota where it will interconnect with the Northern Border Pipeline system in North Dakota. Approximately 53 miles of the proposed route is within the Wyoming PRB Coal Review study area. If constructed, the Bison project would have a capacity of 470 million cubic feet per day with potential to expand to approximately 1,000 million cubic feet per day. Bison filed an application with the Federal Energy Regulatory Commission (FERC) for a certificate of public convenience and necessity to construct, own and operate the pipeline in April 2009 with an in-service estimate of 2010 (Bison Pipeline 2009).
- The proposed Pathfinder Pipeline Project was a 42-inch-diameter, 500-mile-long natural gas pipeline that would cross the Wyoming PRB study area; however, its main supply of gas

would come from the Green River Basin, where it would originate. It is possible that an interconnect at Dead Horse Creek might provide an outlet for PRB-produced gas into Pathfinder. If constructed, the Pathfinder project would have had a 1.2 to 2.0 billion cubic feet per day capacity. TransCanada received a notice of pre-filing on the Pathfinder Project from FERC on June 4, 2008. TransCanada sent a letter to FERC asking that pre-filing activities be suspended on March 23, 2009. TransCanada has no record to indicate termination the Pathfinder docket (Dodson pers. comm.).

- Encore's proposed 231 mile CO<sub>2</sub> pipeline would extend from near Lysite, Wyoming, to the Belle Creek oil production field in Powder River County near Ridge, Montana. The Greencore pipeline would go through the PRB and transport CO<sub>2</sub> used for EOR and carbon sequestration. The pipeline construction is planned to start in the summer of 2011 pending issuance of a federal right of way and surface owner consents. This project is considered to have a high likelihood of completion. Information on this project can be found by contacting the Wyoming Enhanced Oil Recovery Institute.

Beyond the Task 2 study area for the Wyoming PRB, the oil and gas pipeline projects essentially would parallel one another to interconnect with Northern Border's main pipeline in North Dakota. Since these projects would be interstate gas transportation pipelines, they would be regulated by the FERC. Although FERC lists these projects as "on the horizon" (Federal Energy Regulatory Commission 2008), no formal applications have been filed with the regulatory agencies (Federal Energy Regulatory Commission 2008; WDEQ 2008). Both of these projects are dependent upon acquisition of sufficient support in the open season process. Based on the lack of formal applications, their likelihood currently is considered low (BLM 2009c).

Currently proposed and construction-in-progress natural gas transportation pipeline projects would not cross the Wyoming PRB study area; however, they would influence the ability of PRB gas producers to access outside markets. These projects are the Alliance Pipeline (a 42-inch-diameter natural gas pipeline proposed from Wamsutter, Wyoming, to Emerson, Manitoba) and the Rockies Express (from Rio Blanco County, Colorado, to Monroe County, Ohio) (Rockies Express Pipeline LLC 2008; Wyoming Pipeline Authority 2008). The Alliance Pipeline is expected to commence construction in 2012, with a proposed in-service date sometime in 2013. Rockies Express Pipeline (western segment from western Colorado to Missouri) was in-service in January 2008. The expected in-service date for the eastern segment (Missouri to Ohio) is October 2011. Although important to PRB gas producers, because these projects would not cross the Wyoming PRB study area, they are not considered further in this analysis.

The amount of available pipeline capacity could limit the amount of future CBNG development. In the 2005 Task 2 Report (BLM 2005b), it was estimated that growth of Wyoming PRB CBNG production could rise from the 2003 level of 947 million cubic feet per day up to 3 to 4 billion cubic feet per day around 2007 and remain at or above those levels until 2015 (Holcomb 2003). However, production rates of 3 to 4 billion cubic feet per day were not realized by 2007, and the average daily production for all gas (conventional and CBNG) was approximately 1.22 billion cubic feet per day (Wyoming Oil and Gas Conservation Commission 2008). Average CBNG production in 2007 was approximately 1.24 billion cubic feet per day. The addition of the Bison Pipeline Project would increase the take-away capacity of the PRB by approximately 0.5 billion cubic feet per day, resulting in total take-away capacity for the PRB of approximately 2.55 billion cubic feet per day. The addition of the Pathfinder Pipeline Project would increase the

take-away capacity by approximately an additional 1.6 billion cubic feet per day, for a total of approximately 4.15 billion cubic feet per day. Based on the assumptions in the updated Task 2 Report (BLM 2009c), the projected total gas production (conventional and CBNG) would increase to 2.06 billion cubic feet per day in 2010, 2.86 billion cubic feet per day in 2015, and 2.91 billion cubic feet per day in 2020. Therefore, likelihood for additional new pipeline construction for 2010 is low, with a higher likelihood in subsequent years (BLM 2009c).

In the 2005 Task 2 Report (BLM 2005b), it was indicated that Anadarko Petroleum Corporation was planning to extend its CO<sub>2</sub> pipeline that runs between Bairoil, Wyoming, and Salt Creek, Wyoming, to the Sussex Field located in the southern Johnson County portion of the Wyoming PRB study area. However, more recent information indicates that this has not occurred (Anadarko Petroleum Corporation 2008). According to the Wyoming Enhanced Oil Recovery Institute, fields in the Wyoming PRB study area that would be good candidates for EOR using CO<sub>2</sub> include Hartzog Draw, Hilight, and House Creek (Boyles and vant Veld 2006). Laterals from the Greencore Pipeline could be constructed in the future to carry CO<sub>2</sub> to potential oil recovery projects in the Wyoming portion of the PRB; however, no projects are currently planned. The 2005 Task 2 Report (BLM 2005b) projected that basinwide production of CBNG could double by 2020, which would suggest that additional pipelines could be built. The recent update of the that report (BLM 2009c) revised the projections. As noted in Section 4.1, trends in CBNG development since 2007 indicate that this estimate may be lowered as new forecasting is done. Current gas pipeline capacity out of the PRB is approximately 2.05 billion cubic feet per day; average conventional natural gas and CBNG production in 2007 was approximately 1.24 billion cubic feet per day. Based on the information in the updated Task 2 Report (BLM 2009c), potential total gas production (conventional natural gas and CBNG) has been projected at 2.06 billion cubic feet per day by 2010. This potential is pipeline capacity limited, suggesting additional pipelines could be built.

### Refineries

Construction of a new refinery was completed in the Wyoming PRB study area in 2008. The NorthCut Refinery, owned and operated by Interline Resources, is located in Converse County, approximately 20 miles north of the town of Douglas, Wyoming. Construction of the refinery, which was a conversion of the previously existing Well Draw Gas Plant, included installation of a crude oil pipeline between the company's existing crude gathering system and the refinery.

The NorthCut Refinery is a crude oil topping plant, specifically engineered to process 4,000 barrels per day of sweet crude produced in the PRB. Output from the refinery will include naphtha, off-road diesel, and reduced crude oil. The markets for the products include ethanol manufacturers, mines, and other refineries. The company-owned crude oil pipeline and third-party tanker trucks will be used for delivery of crude stocks. Tanker trucks also will be used to transport finished products from the facility (Interline Resources 2008).

The refinery is adjacent to and east of Wyoming 59, with the joint BNSF and UP rail line located just to the west of the highway. The site previously had been the location of the Well Draw Gas Plant (approximately 20 acres), which shut down in 2002 following a fire. Interline has acquired an additional 12 acres bordering the original site for administrative, maintenance, and transportation-related uses (Interline Resources 2008).

The level and composition of outputs from the existing NorthCut Refinery would respond to various markets, potentially resulting in the construction of additional infrastructure and/or facilities in the future. Any future changes and associated disturbances would occur within the property currently owned by Interline Resources at the NorthCut site (Williams pers. comm.). Currently, no specific plans for expansion have been identified. As a result, the likelihood for project expansion currently is considered speculative. Therefore, it has been eliminated from further analysis in this study.

No other reasonably foreseeable plans for construction and operation of new petroleum refineries in the Wyoming portion of the PRB have been identified.

### 4.1.3 Other Development Activity

#### 4.1.3.1 Other Mining

Uranium, sand, gravel, bentonite, and clinker (or scoria) have been and are being mined in the Wyoming PRB study area.

Wyoming has been the nation's leading producer of uranium ore since 1995, and also hosts the nation's largest uranium reserves (Wyoming State Geological Survey 2009). There are three primary uranium mining districts in the PRB: Pumpkin Buttes, Southern Powder River, and Kaycee (BLM 2003). Numerous uranium mining sites, both potential and existing, are present in these districts. Wyoming's only currently producing uranium mines are the Smith Ranch-Highland operation and the Christensen Ranch operation. The Smith Ranch-Highland operation is located in Converse County in the Southern Powder River District, and the Christensen Ranch operation is located in Johnson and Campbell counties in the Pumpkin Buttes area. The Smith Ranch-Highland operation is owned by Power Resources, Inc. (dba Cameco) and uses the in-situ recovery (or in-situ leach) method of mining. Aside from the Smith Ranch-Highland operation, the only other uranium mining operation in the PRB that is currently licensed by the U.S. Nuclear Regulatory Commission (NRC) is the Christensen Ranch/Irigaray operation (owned by COGEMA Mining, Inc.) located in Johnson and Campbell counties (U.S. Nuclear Regulatory Commission 2009).

In the 2005 Task 2 Report (BLM 2005b), reasonably foreseeable uranium development was eliminated from further consideration because: 1) there were no specific projects with pending applications and 2) no development was anticipated, based on market conditions. Based on commodity forecasts and uranium activity as of June 2004, the likelihood and potential timing of new uranium mining operations in the PRB was not known, and additional development was not projected in the PRB Coal Review analysis. Because of increased overall demand for energy in recent years, uranium prices have increased from a low of \$7 a pound in 2001 to over \$138 a pound in 2007 (Barry 2008). The price fell to \$62 in 2008 and is currently in a range of \$40 to \$50 per pound, which is expected to hold through 2010 because of stable demand and a growing supply. The recent upsurge in yellowcake spot prices has increased exploration and claim-staking activity in the PRB and is generating considerable interest in new development (Wyoming State Geological Survey 2009).

In response to the increased price of uranium, a number of uranium mine developments currently are proposed in the Wyoming PRB study area. The NRC is currently reviewing applications for

two new uranium recover facilities in the PRB: the Moore Ranch and the Nichols Ranch-Hank Unit (U.S. Nuclear Regulatory Commission 2009). The Moore Ranch, owned by Energy Minerals Corporation (dba Uranium One), is located in Converse County, and the Nichols Ranch-Hank Unit, owned by Uranerz Energy Corporation, is located in Campbell and Johnson counties. Both of these projects submitted license applications in 2007, they are located in the Pumpkin Buttes District, and would use the in-situ recovery method of mining.

Over the next three years, the NRC expects to receive additional applications for new uranium recovery facilities, as well as requests for restarts and expansions of existing facilities. Table 4-9 provides information on the three new projects and four expansion projects currently proposed in the PRB, all of which would use in-situ recovery. With the exception of the Ross Project, which is located in western Crook County, the proposed developments are all in the Pumpkin Buttes District in southwestern Campbell and northwestern Converse counties. The actual number of the proposed developments that would become operational would depend on several factors including uranium prices and approval of permits.

**Table 4-9. In-Situ Recovery Uranium Projects Currently Proposed in the Task 2 Study Area for the Wyoming portion of the PRB**

Project/Company	County	Application Type	Watershed/Mining District	Likelihood/Rationale
Ludeman Satellite Project/Energy Metals Corp (dba Uranium One)	Converse	Expansion/Amendment to Moore Ranch	Antelope Creek/Pumpkin Buttes District	Moderate for 2012/Letter of intent to NRC February 2009, application expected 2009.
Allemand-Ross Satellite Project/Energy Metals Corp (dba Uranium One)	Converse	Expansion/Amendment to Moore Ranch	Antelope Creek/Pumpkin Buttes District	Moderate for 2012/Letter of intent to NRC February 2009, application expected 2009.
Ross Project/Peninsula Minerals, Ltd.	Crook	New	Little Missouri River/not in one of the three districts	Moderate for 2012/Letter of intent to NRC October 2009, application expected 2010.
Collins Draw Project/Uranerz Energy Corporation	Campbell	New	Powder River/Pumpkin Buttes District	Moderate for 2012/Letter of intent to NRC March 2008, application expected 2009.
North Butte-Ruth Project/Power Resources, Inc. (dba Cameco)	Campbell and Johnson	Expansion/Satellite to Smith Ranch	Powder River/Pumpkin Buttes District	High probability for 2012/Application for commercial operation filed March 2006.
Reno Creek Project/Bayswater Uranium Corporation	Campbell	New	Belle Fourche River and Antelope Creek/Pumpkin Buttes District	Moderate for 2015/Letter of intent to NRC March 2009, application expected 2010.
Ruby Ranch Project/Power Resources, Inc. (dba Cameco)	Campbell	Expansion/Satellite to Smith Ranch	Powder River and Belle Fourche River/Pumpkin Buttes District	Moderate for 2015/Letter of intent to NRC March 2008, application expected 2009.

NRC = U.S. Nuclear Regulatory Commission

Sources: U.S. Nuclear Regulatory Commission (2009), World Information Service on Energy (2009).

Bentonite is weathered volcanic ash that is used in a variety of products, including drilling mud and cat litter, because of its absorbent properties. There are three major bentonite producing districts in and around the PRB: the Colony District in the Northern Black Hills, the Clay Spur District in the Southern Black Hills, and the Kaycee District west of Kaycee, Wyoming. Within the PRB Coal Review study area, bentonite is mined at Kaycee (Wyoming Mining Association 2006). The PRB Coal Review assumed that bentonite mining would continue throughout the study period and that production would continue at existing active mines, with no new mines developed through 2020.

Aggregate (i.e., sand, gravel, and stone) is used for construction purposes. In the PRB, the more important aggregate mining localities are in Johnson and Sheridan counties (Wyoming State Geological Survey 2004). The largest identified aggregate operation is located in northern Converse County. It has an associated total disturbance area of approximately 67 acres, of which 4 acres have been reclaimed.

Clinker (known locally as scoria or red dog), which is formed when coal beds burn and the adjacent rocks become baked, is used as aggregate where alluvial terrace gravel or in-place granite/igneous rock is not available. Clinker generally is mined in Converse and Campbell counties in the Wyoming PRB study area.

Increased sand, gravel, and clinker production and associated surface disturbance are anticipated in the Wyoming PRB study area in the future because aggregate would be required for road maintenance and new construction activities as other primary resources, such as coal and oil and gas, continue to be developed. New operations and increased production from existing operations can be expected. These operations would vary in size based on the immediate need from the primary industries, but there is no specific information about these projected operations. As a result, new sand, gravel, or clinker operations were not analyzed in detail in the PRB Coal Review.

#### *4.1.3.2 Industrial Manufacturing*

A number of existing industrial manufacturing establishments are located in the Wyoming PRB Coal Review study area. Most are relatively small with fewer than 25 employees; they predominately serve regional and local markets, and most are directly or indirectly related to energy resource development and production. Over the years, some of these firms have expanded such that they now support activities and serve markets outside of the region, but those operations remain dependent upon the local and regional markets to sustain their existing operations.

The PRB Coal Review anticipates that increased coal production would result in an increased demand for fuels and explosives. This increased demand could result in the need for the development of new off-site chemical feedstock plants in the study area. Project-specific information is not available; however, and the potential development of new chemical feedstock plants was not considered in the PRB Coal Review.

Local economic development organizations, including Campbell County Economic Development Corporation and Converse Area New Development Organization, are continually engaged in efforts to recruit or assist new business formation in the PRB study area. For example, the latter has pursued development of long-term potential projects; however, the

outcomes of those projects are uncertain and little information and detail are available. As a result, they were not considered in the PRB Coal Review.

#### 4.1.3.3 Wind Power

Because of increasing concerns over global climate change, there is strong interest from consumers, investor-owned utilities, and environmental and economic sustainability interests in wind energy generating projects and other forms of renewable energy projects. The current development interest in wind energy generation is driven in part by mandates for many utilities to increase the use of renewables in their overall energy portfolio, decisions by environmentally conscious firms to use renewable energy sources, and also because of the development of wind energy manufacturing infrastructure in the region.

Wind power facilities have been proposed, are being constructed, and are providing energy at various sites in Wyoming, including the PRB. There is good potential for wind power, and these facilities can contribute to meeting forecasted electric power demands; however, they are dependent on available transmission capacity to send power to users. Among the lower 48 states, Wyoming currently ranks in eleventh place in terms of existing wind power capacity with 986 MW currently in operation and 299 MW under construction. Texas ranks in first place with 8,797 MW in operation and 660 MW under construction. In terms of annual wind energy potential, Wyoming ranks seventh with 747 billion kilowatt-hours per year. North Dakota ranks first with 1,210 billion kilowatt-hours per year (American Wind Energy Association 2010). Although many Wyoming locations having the highest potential are in the southern portion of the state, areas in both Converse and Campbell counties offer sufficient potential to support commercial-scale wind generation projects.

- One such project, the Glenrock Wind Farm, is currently providing power in the Wyoming PRB study area. PacifiCorp completed construction of this three-phase project in Converse County in 2009. The Glenrock Wind Farm is located approximately 15 miles north of the existing Dave Johnston Power Plant, on and near the site of the former Dave Johnston Coal Mine. This is the first wind energy project in the nation to be located at a reclaimed coal mine. The first phase, known as the Glenrock Wind Energy Project, went online in 2008. The second and third phases, the Rolling Hills Wind Energy Project and the Glenrock III Wind Energy Project, respectively, went online in 2009. The Glenrock and Rolling Hills phases each consist of 66 wind turbine generators (each rated at 1.5 MW [99 MW total]). The Glenrock III phase consists of 26, 1.5-MW wind turbines (39 MW total) (PacifiCorp 2009).
- Duke Energy (dba Three Buttes Windpower, LLC) completed the Campbell Hill Windpower Project and began commercial operations in December 2009. The Campbell Hill Windpower Project is located approximately 15 miles northeast of Casper in Converse County and consists of 66 wind turbines generating 99 MW. PacifiCorp will buy all of the output generated by the project.
- Duke Energy plans to build the Top of the World Wind Energy Project, a 200-MW wind farm located northeast of Glenrock in Converse County. Construction was expected to begin in early 2010 upon receipt of all necessary permits from the state. PacifiCorp will buy the power generated by the project (Duke Energy 2009).

- Third Planet Windpower is in the initial development phase of a wind energy project (Reno Junction Windfarm) in the Pumpkin Buttes area of southwestern Campbell County. Third Planet Windpower has acquired approximately 13,000 acres of land leases for the project, installed meteorological monitoring sites, and is currently doing environmental and feasibility studies. The company plans to install up to 133, 1.5-MW towers, yielding a total capacity of 200-MW, if fully constructed. The site for the Reno Junction Wind Farm is close to the Black Hills Power Pumpkin Buttes substation and the companies are seeking an agreement for interconnection. Construction was expected to begin in mid-2010, with an online date anticipated for the end of 2010 (Rogers 2008). This project is considered moderately likely to occur (BLM 2009c).

Land use disturbance for wind energy projects is associated with development of access roads, a turbine assembly pad, and foundation pad for each wind turbine tower. Additional land disturbance results from installation of transformers and substations, underground electric and fiber optic communications cables, one or more operations and maintenance facilities, meteorological towers, and a transmission line connecting the project to the regional grid. Much of the disturbance area is reclaimed immediately following construction, with long-term disturbance associated with permanent facilities (i.e., access roads, support facilities, and tower foundations).

Wind generating projects have an expected life of approximately 25 years, which could be extended based on market conditions and the overall condition of the infrastructure. Some redisturbance would occur at the time of decommissioning, followed by final reclamation.

According to the American Wind Energy Association (2010), transmission will be a key issue for the wind industry's future development over the next two decades.

#### 4.1.3.4 Solar Power

Although Wyoming has been given a rating of 5,000 to 5,500 watt hours per square meter per day solar resource for flat plate collectors, currently, no utility-scale solar power collection facilities are located on federal, state, or private lands in Wyoming. Furthermore, no applications for the development of utility-scale solar energy projects had been filed as of June 1, 2011.

The BLM, the Office of Energy Efficiency and Renewable Energy, and the DOE are jointly preparing a solar energy programmatic EIS which could facilitate future solar energy development application processes. Wyoming is not covered in the programmatic EIS but still may be affected by it. Information on the programmatic EIS can be found at: <http://solareis.anl.gov>. The BLM currently evaluates solar energy project proposals on a case-by-case basis.

Solar energy use in Wyoming is, as of January 1, 2010, limited to private residences and private commercial establishments. Current Wyoming solar energy incentives include a sales tax rebate on industrial or commercial solar energy generation equipment, a one-time grant of up to \$3,000 offered through lottery from the Wyoming Business Council, and the utility buy back of unused electricity at the wholesale price. Solar energy production equipment and installation at residential, commercial, and utility sites is expensive. Currently, the electric utility costs in Wyoming are such that the cost of installation does not favor solar energy development over existing forms of energy development.

#### 4.1.3.5 Reservoirs

Currently, five key water storage reservoirs are present in the Wyoming PRB Coal Review study area: Healy, Lake DeSmet, Muddy Guard No. 2, Gillette, and Betty No. 1 (HKM Engineering et al. 2002a and 2002b). The total surface disturbance associated with these water storage areas is 3,263 acres.

Based on the applicable water plans prepared for the Wyoming Water Development Commission for its Basin Planning Program (HKM Engineering et al. 2002a and 2002b), there are long-range projections for development of additional reservoirs in the Wyoming PRB study area. However, none of these reservoirs have reached the planning stage; therefore, there was not enough information to analyze them in the PRB Coal Review.

#### 4.1.3.6 Other Non-Energy Development

In addition to the specific projects and developments described above, a network of public and private physical infrastructure, private enterprises, and public activities has been developed in the PRB over time. Examples of infrastructure include the highway and road networks, airports, government offices, hospitals, public schools, municipal water systems, and extensive residential and commercial real estate development. Private enterprises include local retail and service establishments, newspaper publishing, and transportation and distribution firms.

There are a number of existing industrial manufacturing and service establishments located in the Wyoming PRB study area. Most are relatively small with fewer than 50 employees, and most serve local and regional markets, the majority of which are directly or indirectly related to energy resource development and production. Hettinger Welding and L&H Welding and Machine, both based in Gillette, are the largest industrial manufacturing firms in the region specializing in repairs, rebuilding, and manufacturing for the mining industry. Though classified as wholesalers and repair establishments, rather than as manufactures, firms such as Wyoming Machinery and P&H Mining Equipment also serve the mining and oil and gas industries. Other industrial manufacturing and service establishments in the region provide metal fabrication, metal plating, custom and precast concrete products, and specialized chemical products and services. Over the years, some of these firms have expanded such that they now support activities and serve markets outside the PRB region. However, they remain dependent upon the local and regional markets to sustain their existing operations (BLM 2009c).

Local economic development organizations, including Campbell County Economic Development Corporation and Converse Area New Development Organization are continually engaged in efforts to recruit or assist new business formation in the PRB study area. For example, the Converse Area New Development Organization is pursuing development of an ammonium nitrate plant (using methane as a feedstock) in the Bill, Wyoming, area, as well as location of an aluminum mill in the same general location. These and similar prospects are long-term potential whose outcomes are uncertain and for which little information and detail are available. As a result, they were eliminated from analysis in the PRB Coal Review (BLM 2009c).

Local governments, school districts, and other special service districts and public entities continually engage in long-term planning. Examples of some of the recently completed projects and developments, as well as anticipated plans or proposals for development in public, private,

and commercial infrastructure in the City of Gillette and Campbell County, are included in the current City of Gillette development summary (City of Gillette 2009) and are summarized below.

- The City of Gillette's Wastewater Treatment Plant was upgraded in 2007.
- An expansion and renovation of the county courthouse were completed in 2006, and a new public health building was completed in 2007.
- The Wyoming Center, a conference and multi-event facility expansion of the Gillette CAM-PLEX, was completed in 2008 annual. The expansion includes more exhibit space, conference and indoor athletic facilities with seating for up to 9,000, an indoor ice rink, and various concession and support spaces.
- A new \$10 million headquarters for the Campbell County Fire Department providing administrative, training, storage space, and additional parking bays for firefighting equipment and vehicles was completed in 2008.
- A new Hospice Center, the Cummins Diesel Service Center, and the Hillcrest School were completed in 2008.
- Construction of the new Health Sciences Center at Gillette College was completed in 2008. The facility houses the school's nursing program, providing classrooms, labs, faculty offices, and other spaces. The nursing program functions in conjunction with the Campbell County Memorial Hospital
- Major infrastructure projects within and adjacent to the city limits in 2008 and 2009 included highway and roadway improvements, drainage system improvements, library renovations, subdivision developments, and expansion of the county landfill.
- Expansion of the Campbell County Detention Center and remodeling of the Sheriff's Office were completed in 2009.
- Construction of various commercial and residential housing developments is ongoing.
- The new \$55 million Campbell County Recreation Center was completed and opened in April 2010.
- The county, city, and Gillette College are partnering on a Campus Housing Complex and the Industrial Technical Education Center. Construction of these facilities is ongoing and part of a long-range master plan for the college that is designed to provide a broad college-level curriculum and provide more focused education and training to support local business and industry. The 100-bed Gillette College Student Housing project was completed and opened for use in September 2009. The \$55 million, 97,700-square foot Technical Education Center opened in January 2010.
- Campbell County Memorial Hospital is undergoing a major expansion and renovation project that began in 2009 and is expected to be completed in 2011.
- The new Hillcrest Elementary School in Gillette has been completed and opened in September 2009.
- The Burma Road extension is under construction. It will provide a north-south route across I-90 connecting the hospital area with Lakeway Road. This will improve traffic flow, and

open up more land for future development. The section across I-90 opened in August 2010 with full completion of the project projected for spring 2011.

- The City of Gillette is seeking state and local funding to construct an additional municipal water supply. Construction of a second Madison Formation well field in Crook County near the Keyhole Reservoir and a second water supply line from the well field to Gillette is expected to begin in 2011 or 2012.
- The Wyoming School Facilities Commission oversees all aspects of construction and maintenance of school facilities and physical plant. School districts submit five-year plans for facilities spending, which are subject to approval and funding by the commission. Currently approved master plans for the seven school districts serving some portion of the Wyoming PRB study area include defined needs for more than \$115 million in capital construction, some of which have already been funded; the total includes approximately \$51 million for the Campbell County School District, the bulk of which would fund three new elementary schools and one new high school (Wyoming School Facilities Commission 2008).

Additional private sector industrial and commercial development is expected to occur within the context of normal community and economic development. The strong economic base provided by the coal mines, oil and gas companies, and relatively high income of residents draws regional and national retailers (e.g., The Home Depot) to the area. Gillette's location on I-90 and the strong demand for lodging by energy workers, travelers, and visitors associated with events at the CAM-PLEX also have spurred construction of several new motels (Campbell County Economic Development Corporation 2008; City of Gillette 2008a).

- The 2010 Wyoming Department of Transportation State Transportation Improvement Program includes planned construction for the 2010 fiscal year and preliminary engineering estimates for projects with anticipated construction dates through 2015. In general, Wyoming transportation projects scheduled over the next six years include maintenance, reconstruction, and improvement projects. Airport improvement plans consist primarily of pavement rehabilitation and overlays, with some minor expansion of taxiways, aprons, and parking. Costs anticipated for 2010 through 2015 for highway and airport maintenance, reconstruction, and improvement projects in the PRB Coal Review study area (Sheridan, Johnson and Campbell counties) are approximately \$190 million. No construction of new highways is scheduled, and no new airports are proposed.
- In addition to highway projects included in Wyoming Department of Transportation's 2008–2013 plan, the Eagle Butte Mine received approval from WYDOT to relocate a portion of U.S. Highway 14-16 in the vicinity of the Gillette–Campbell County Airport, north of the city of Gillette. The relocation will facilitate the recovery of approximately 40 million tons of additional coal recently acquired by the mine through the West Eagle Butte West LBA tract coal sale. Three alternative alignments, involving the construction of up to 6.8 centerline miles of new roadway, were identified and a preferred alternative was subsequently chosen and approved by the department. Construction of the new highway segment is anticipated in 2011/2012 (Wyoming Department of Transportation and Foundation Coal Company 2008).

There are numerous current and anticipated plans for future investment in public and private infrastructure in the PRB. Such investments would include state and local investment in transportation, administrative, and educational facilities. Given the timing, scale, year-to-year variability, relatively short construction timetables associated with such investments, the existence of a relatively large and diversified construction industry in the region and nearby areas, and the limited potential for these projects to alter long-term conditions in the PRB, they are not included in the PRB Coal Review analysis. However, one or more of these and similar projects could warrant consideration in a cumulative analysis for a site-specific project because of proximity or coincidental project schedules and timetables (BLM 2009c).

## **4.2 Affected Environment and Cumulative Environmental Consequences**

This section summarizes the existing conditions based on the results of the Task 1 Report and the cumulative environmental consequences of projected development for 2010, 2015, and 2020, based on the Task 3 report.

As discussed in section 4.0, the Wyoming portion of the PRB is the primary focus of the PRB Coal Review analyses. For the majority of resources in the Task 1 analysis, the Wyoming PRB Coal Review study area encompasses all of Campbell County, all of Sheridan and Johnson counties outside of the Bighorn National Forest, and the northern portion of Converse County (map 4-1). The study areas for the Task 3 analyses are different. For the majority of the resources considered in the PRB Coal Review, the Task 3 study area is based on watershed boundaries in the PRB and includes the portions of the Upper Powder River, Little Powder River, Upper Belle Fourche River, Upper Cheyenne River, Antelope Creek, and Dry Fork Cheyenne River subwatersheds that lie within Sheridan, Johnson, Campbell and northern Converse counties (map 4-2). This analysis region includes over 4 million acres and is referred to below as the Task 3 study area. Table 4-10 summarizes the total disturbance and reclamation acreages for the 2003 baseline, 2007 actual, and the total projected disturbance and reclamation acreages for 2010, 2015, and 2020 in the Task 3 study area.

A total of approximately 210,096 acres (5%) within the Task 3 study area had been disturbed by cumulative development activities as of 2003. Based on the information presented in Appendices A and D of the updated Task 2 Report (BLM 2009c), approximately 222,568 acres (5%) had been disturbed by development activities by the end of 2007. Of those 222,568 acres of cumulative disturbance, approximately 83,593 acres (38%) were associated with coal mine development.

Of the 222,568 total acres of actual cumulative disturbance documented through 2007, approximately 113,382 acres (51%) have been reclaimed. The remaining 109,186 acres of disturbance would be reclaimed incrementally or following a project's completion, depending on the type of development activity and permit requirements.

**Table 4-10. Actual and Projected Wyoming PRB Total Development Scenario, Task 3 Study Area**

Year	Total Acres Disturbed	Total Acres Reclaimed	Acres Unreclaimed	Acres Unavailable for Reclamation <sup>a</sup>	Acres Affected by Coal Development <sup>a</sup>
Actual					
2003	210,096	111,879	98,217	24,097	68,794
2007	222,568	113,382	109,186	24,338	83,593
Projected Development—Lower Coal Production Scenario					
2010	278,209	159,291	118,918	26,338	98,662
2015	354,148	219,816	134,332	27,549	117,236
2020	422,727	289,937	132,790	28,797	137,443
Projected Development—Upper Coal Production Scenario					
2010	281,996	161,124	120,872	25,688	102,448
2015	361,456	224,024	137,432	27,099	124,545
2020	576,646	397,155	179,491	28,345	149,089

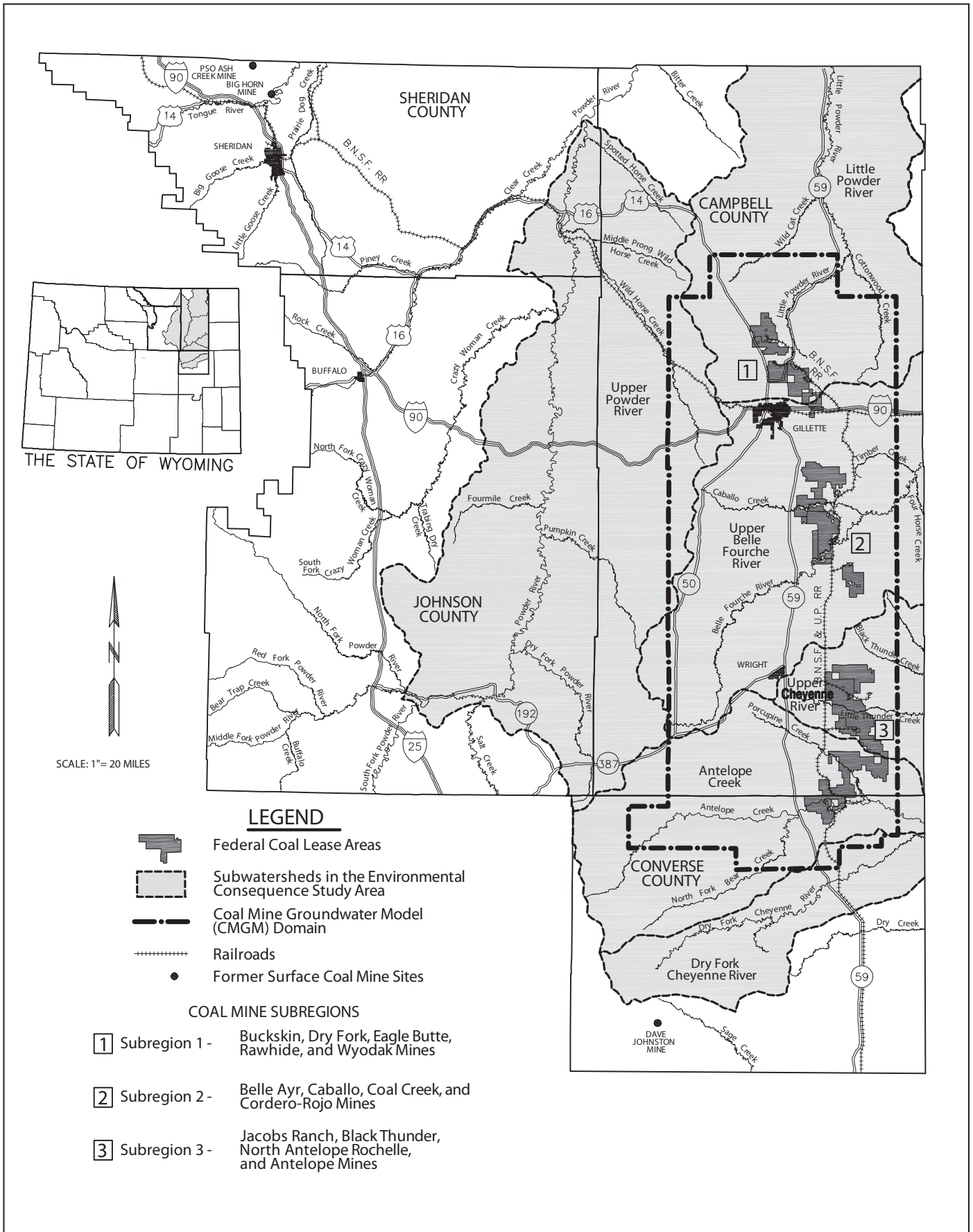
<sup>a</sup> Includes coal mine and coal-related disturbance; those acres will be reclaimed when mine operations end.  
Source: Updated Task 2 Report (BLM 2009c).

Of the 83,593 total cumulative acres of disturbance directly associated with coal mine development through 2007, approximately 25,884 acres (31%) have been reclaimed. Of the remaining 57,709 acres of coal-related disturbance, approximately 24,338 acres (42%) currently are not available for reclamation, as they are occupied by long-term facilities necessary to conduct mining operations. These areas would be reclaimed near the end of each mine's life. Reclamation of the remaining 33,371 acres (58%), which represent areas of active mining and areas where coal has been recovered but reclamation has not been completed, would proceed concurrently with coal mining.

The total cumulative disturbance is projected to increase to as much as 576,646<sup>2</sup> acres in 2020 under the upper coal production scenario (table 4-10), which would represent approximately 12.9% of the study area. This projected disturbance includes coal mining, coal-related development, and oil and gas and related development disturbance in the study area. Of those 576,646 acres, it is projected that 149,089<sup>3</sup> acres (26%) would be associated with coal mining activities. Oil and gas related disturbance represents over 70% of the remaining cumulative disturbance.

<sup>2</sup> Data for 2020 total cumulative disturbance and reclamation projections obtained from Appendix C, Table C-3 in the updated Task 2 Report (BLM 2009c).

<sup>3</sup> Data for 2020 cumulative coal-related disturbance and reclamation projections obtained from Appendix A, Table A-2 in the updated Task 2 Report (BLM 2009c). Math errors in that update have been corrected in table 4-10 and the above text for the Hay Creek II final EIS.



No warranty is made by the Bureau of Land Management for the use of the data for purposes not intended by BLM.

Areas reclaimed during each future time period shown in table 4-10 reflect the amount of disturbed acreage projected to be permanently reclaimed by that respective point in time. For example, under the upper coal production scenario for 2020, of the 576,646 acres of total cumulative disturbance, approximately 397,155 (69%) would be reclaimed by 2020. The remaining 179,491 acres (31%) of disturbance would be reclaimed incrementally or following a project's completion, depending on the type of development activity and permit requirements.

Of the 149,089 acres of cumulative disturbance projected to be associated with coal mining through 2020, approximately 86,196 (58%) would be reclaimed by 2020. Of the remaining 62,893 acres of coal mining-related disturbance, it is estimated that approximately 28,345 acres (45%) would be unavailable for concurrent reclamation due to the presence of long-term facilities, which would be reclaimed near the end of each mine's life. Reclamation of the remaining 34,548 acres (55%) of projected disturbance through 2020 would proceed concurrently with mining operations.

The acres of unreclaimed disturbance would be reclaimed incrementally or following a project's completion, depending on the type of development activity and permit requirements. The acres currently not available for reclamation are occupied by long-term facilities that are needed to conduct mining operations or coal-related activities. These areas would be reclaimed near the end of each mine or facility's life.

The PRB Coal review study areas are defined by discipline for projected environmental consequences, with some changes to the watershed map (map 4-2) as defined below.

- The potential air quality impacts were evaluated over a multi-state area (including most of Wyoming, southeastern Montana, southwestern North Dakota, western South Dakota, and northwestern Nebraska) because they would be expected to extend beyond the Wyoming and Montana PRB air quality study area that was used to identify emissions sources for the air quality analysis.
- The socioeconomic impact analysis focused on Campbell County, but also considered Converse, Crook, Johnson, Sheridan, and Weston counties as directly affected and Niobrara and Natrona counties as indirectly affected.
- The groundwater drawdown was evaluated in the area surrounding and extending west of the surface coal mines shown on map 4-2 (groundwater study area), because that is the area where groundwater drawdown related to surface coal mining operations and CBNG production operations would overlap.

#### 4.2.1 Topography and Physiography

The PRB is located within the Upper Missouri Basin Broken Lands physiographic subprovince that includes northeastern Wyoming and eastern Montana to the Canadian border. The topography generally is of low to moderate relief with occasional buttes and mesas. The general topographic gradient slopes down gently from southwest to northeast with elevations ranging from 5,000 to 6,000 feet above sea level on the southern and western portions of the PRB to less than 4,000 feet above sea level on the north and northeast along the Montana state line. The major drainages in the PRB are the Tongue, Powder, Belle Fourche, and Cheyenne rivers. Most of the drainages in the area are intermittent and have flows during high precipitation events or

during periods of snowmelt. The drainages are part of the upper Missouri River Valley drainage basin.

The disturbance associated with the majority of the past, present, and projected activities have resulted in or would result in the alteration of the surface topography. Surface coal mining, which is projected to continue in the area of the existing coal mines shown on map 4-2, permanently alters the topography by removing the overburden and coal and then replacing the overburden.

Recontouring during reclamation to match approximate original contours, as required by regulation, reduces the long-term impact on topography. After mined-out areas are reclaimed, the restored land surfaces are typically gentler, with more uniform slopes and restored basic drainage networks. Oil and gas exploration and development has occurred and is projected to continue throughout most of the Task 3 study area. It also results in the alteration of topography to accommodate facilities (e.g., well pads, power plants) and roads, but the disturbance tends to occur in smaller, more discrete areas than coal mining and the development is spread out over a larger area.

The disturbance and reclamation acreages associated with all existing and projected development in the Task 3 study area for the years 2003, 2007, 2010, 2015, and 2020 are given in table 4-10.

### 4.2.2 Geology, Mineral Resources, and Paleontology

The study area for geology, mineral resources, and paleontology is the Task 3 study area (map 4-2).

#### 4.2.2.1 Geology

The PRB is one of a number of structural basins in Wyoming and the Rocky Mountain area that were formed during the Laramide Orogeny events. The basin is asymmetric with a structural axis that generally trends northwest to southeast along the western side of the basin (Flores et al. 1999). Natural earthquakes, landslides, and subsidence do not present a hazard in the PRB based on the lack of active faults in the study area (U.S. Geological Survey 2004); the low risk of ground shaking in the PRB if a maximum credible earthquake were to occur (Frankel et al. 1997); and the absence of evidence of subsidence, landslides, or other geologic hazards in association with CBNG production. USGS monitors the magnitude of blasting activity in the PRB under the Routine Mining Seismicity Earthquake Hazards Program (U.S. Geological Survey 2008). Seismic activity induced by coal mine blasting operations occurs throughout the PRB and has reached a USGS local magnitude rating of 3.6 in some instances (U.S. Geological Survey 2004).

#### 4.2.2.2 Mineral Resources

##### **Coal**

Most of the coal resources in the PRB are found in the Fort Union and Wasatch formations; however, coal layers in the Wasatch formation are thinner and less continuous than those in the Fort Union formation. Therefore, Wasatch coal is not as economically important as Fort Union

coal for either coal mining or CBNG development. Projected levels of coal production and disturbance under the lower and upper coal production scenarios are listed in tables 4-2 and 4-3.

In the coal mine areas, the overburden and coal would be removed and the overburden replaced, resulting in a permanent change in the geology of the area and a permanent reduction of coal resources.

### Oil and Gas

Drilling for conventional oil and gas in the Wyoming PRB has declined considerably in the last 15 years. However, as discussed above, increasing prices have led to increased interest in drilling, and there remains potential for finding and developing these resources in the deeper formations of the basin. Conversely, CBNG production increased rapidly from 1999 through 2002 but began to level off in 2003. Actual production rates for conventional oil and gas and CBNG in 2007 and projected rates for 2010, 2015, and 2020 are shown in tables 4-6 and 4-7.

Oil and gas and related development accounts for most of the projected mineral disturbance outside of the coal mining areas. It generally would result in only shallow, discrete areas of surface disturbance, as discussed above. The acreages over which these impacts were occurring (as of 2003 and 2007) and are projected to occur in the years 2010, 2015, and 2020 are included in the totals in table 4-10.

### Other Mineral Resources

As discussed in section 4.1.3.1, other mineral resources that are being mined in the Wyoming PRB include uranium, bentonite, clinker, and aggregate. Production of uranium and bentonite is not likely to be affected by development of coal or CBNG in the PRB. Aggregate and clinker production levels are more likely to be affected by other mineral development levels because these resources would be used in construction projects related to other mineral development.

#### 4.2.2.3 *Paleontology*

Paleontological Resources are any fossilized remains, traces, or imprints of organisms, preserved in or on the earth's crust, that are of paleontological interest and that provide information about the history of life on earth. Scientifically significant paleontological resources (including vertebrate, invertebrate, plant, and trace fossils) are known to occur in many of the geologic formations within the Wyoming PRB. These paleontological resources are documented in the scientific literature, in museum records, and are known by paleontologists and land managers familiar with the area. It has been determined that paleontological resources on federal land shall be managed and protected using scientific principles and expertise. Appropriate plans for the inventory, monitoring, and the scientific and educational use of these resources shall be developed, in accordance with applicable agency laws, regulations, and policies. These plans shall emphasize interagency coordination and collaborative efforts where possible with non-federal partners, the scientific community, and the general public.

Significant paleontological localities have been recorded on federal lands in some areas of the PRB. However, the absence of localities in the PRB does not always mean that scientifically significant fossils are not present, as much of the area within and surrounding the PRB has not been adequately explored for paleontological resources. As a result, development activities in

the Task 3 study area have the potential to adversely affect scientifically significant fossils, if they are present in or adjacent to disturbance areas.

The potential for impacts to scientifically significant paleontological resources are predicted to be greatest in areas where PFYC Class 4 or 5 (High or Very High) formations are present (see section 3.3.3.1). In addition, in most cases those rock units with a PFYC of 3 (Moderate or Unknown) will require some management decision and action. Class 3 formations are fossiliferous units where fossil content varies in significance, abundance, and predictable occurrence; or of unknown fossil potential. Surface-disturbing activities will require sufficient assessment to determine whether significant paleontological resources occur in the area of a proposed action, and whether that action could affect the paleontological resources.

The Wasatch Formation is the most geographically widespread unit exposed on the surface over most of the Task 3 study area. It is underlain by the Fort Union Formation. The fossiliferous (PFYC 5) Sundance, Morrison, Cloverly, and Lance formations crop out along the margins of the basin and occur at depth in the vicinity of the coal mines and CBNG activity in the eastern portion of the basin. Within the Task 3 study area, the highly fossiliferous (PFYC 5) White River Formation occurs only on Pumpkin Buttes in southwestern Campbell County.

In recent years, the Wasatch Formation has been downgraded to a Class 3a formation (geologic units with widely scattered scientifically significant fossils) in the PRB, but remains a Class 5 formation (highest rating) statewide. The Fort Union Formation is under consideration to be upgraded from a Class 3 (geologic units where fossil content varies in significance, abundance, and predictable occurrence; or of unknown fossil potential) to a Class 4 formation (geologic units containing a high occurrence of scientifically significant fossils) statewide. The Potential Fossil Yield Classifications of these rock units, as well as many others in Wyoming, are currently under revision and may change in the near future.

The greatest potential impact on surface and subsurface paleontological resources would result from disturbance of surface sediments and shallow bedrock during construction and/or operations, depending on the type of project. Potential subsurface disturbance of paleontological resources (e.g., during drilling operations) would not be visible or verifiable. The areas over which these impacts occurred as of 2003 and 2007, and are projected to occur as a result of all projected development in the years 2010, 2015, and 2020, are shown in table 4-10. However, as only portions of the Task 3 study area have been evaluated for the occurrence of paleontological resources, and discrete locations for development activities cannot be determined at this time, no accurate estimate can be made as to the number of paleontological sites that may be affected by cumulative development activities. Development activities which involve federally owned surface and/or minerals are subject to federal guidelines and regulations protecting paleontological resources. Protection measures, permit conditions of approval, and/or mitigation measures would be determined on a project-specific basis at the time of permitting to minimize potential impacts on paleontological resources as a result of these activities.

### 4.2.3 Air Quality

There is substantial scientific evidence that increased atmospheric concentrations of GHG and land use changes are contributing to an increase in average global temperature. As of January 1, 2011, GHG are regulated pollutants. A discussion of this subject has been included in section 4.2.14.

The 2005 Task 1A Report (BLM 2005a) documents the modeled air quality impacts of operations during a baseline year, 2002, using actual emissions and operations for that year. Emissions from permitted minor sources were estimated, because actual emissions data was unavailable. The baseline year analysis evaluated impacts both within the PRB itself and at selected sensitive areas surrounding the region. The analysis specifically looked at impacts of coal mines, power plants, CBNG development, and other development activities. Results were provided for both Wyoming and Montana at the individual receptor areas. The 2005 Task 2 Report (BLM 2005b) identifies reasonably foreseeable development activities for the years 2010, 2015, and 2020.

The 2006 Task 3A Report (BLM 2006d) evaluates the impacts on air quality and air quality-related values for the year 2010 using the development levels projected for 2010—the same model and meteorological data that were used for the baseline year study in the Task 1A Report (BLM 2005a). The BLM updated the model and conducted an impact analysis for the year 2015. This updated model is reflected in the 2008 update to the Task 3A Report (BLM 2008a), which uses a revised baseline year of 2004 and revised projected scenarios for the year 2015. The BLM updated the model again in 2009 and conducted an impact analysis for the year 2020. The most recent update to the Task 3A Report for 2020 (BLM 2009d) uses the same baseline year of 2004 with revised projected scenarios for the year 2020. A revised baseline year emissions inventory was developed using 2004 actual emissions data or emissions estimates and has incorporated the recent analyses of emissions in Wyoming and Montana, which were not available when the 2010 modeling study was done.

Existing and projected emissions sources for the revised baseline year (2004) and 2015 and 2020 analyses were identified within a study area comprised of the following counties in the PRB in Wyoming and Montana:

- Campbell County, all of Sheridan and Johnson counties except the Bighorn National Forest lands west of the PRB, and the northern portion of Converse County, Wyoming; and
- Rosebud, Custer, Powder River, Big Horn, and Treasure counties, Montana.

A state-of-the-art, guideline dispersion model was used to evaluate impacts of the existing and projected source emissions on several source groups, as follows:

- near-field receptors in Wyoming and Montana covering the Task 1A and 3A study areas in each state (overall, the near-field receptor grid points were spaced at 1-kilometer intervals over the study area);
- receptors in nearby federally designated pristine or Class I areas; and
- receptors at other sensitive areas (Class II sensitive areas).

The EPA guideline CALPUFF model system version 5.8 (Scire et al. 1999a) was used for this study, which differs from the version used in the Task 1A and original Task 3A studies. The impacts for the baseline year (2004) and for 2015 and 2020 lower and upper coal production scenarios were directly modeled. As discussed above, the modeling domain extends over most of Wyoming, southeastern Montana, southwestern North Dakota, western South Dakota, and western Nebraska. An interagency group participated in developing the modeling protocol and related domain that were used for this analysis.

The modeling approach for the updated Task 3A Report used actual emissions from existing sources representative of 2004 operations and projected those emissions for the expected level of development in 2015 and in 2020 (BLM 2009d). Year 2004 emission inventory data were previously developed for the Montana Statewide Oil and Gas Supplemental EIS. No specific emissions data were available for the projected levels of development. The baseline year emissions data were gathered from a variety of sources but mainly relied on data collected by the WDEQ and the Montana Department of Environmental Quality. Only actual emission sources inside the study area described above were included in the modeling. Key major sources were included, such as the coal-fired power plants, gas-fired power plants, and sources that were included in the Title V (operating permit) program. The Dave Johnston power plant, which is located outside of but adjacent to the study area in Converse County, was included in the baseline year study and in the projected emissions. Some operational adjustments were made to accommodate small sources with air permits that were presumed to be operating at less than full capacity. Emissions from other sources, including estimated construction-related fugitive dust emissions, were computed based on EPA emission factors and on input data from the WDEQ.

The PRB Coal Review generally considers existing regional air quality conditions in the Task 1A and Task 3A study areas to be very good. There are limited air pollution emissions sources (few industrial facilities, including the surface coal mines, and few residential emissions in relatively small communities and isolated ranches) and good atmospheric dispersion conditions. The available data show that the region complies with the ambient air quality standards for NO<sub>2</sub> and SO<sub>2</sub>. There have been no monitored exceedances of the annual PM<sub>10</sub> standard in the Wyoming PRB.

Air quality modeling indicates the projected mine activities at the Buckskin Mine will comply with the PM<sub>10</sub> and PM<sub>2.5</sub> near-field and short-term NO<sub>2</sub> air standards for the 2015 and 2020 modeled air quality impacts at the currently permitted mining rate. The applicant has indicated that they propose to mine either action alternative at a rate (average of 25 million tons per year) well below its currently permitted level (42 million tons per year). Visibility data collected around the region indicate that, although there are some days with notable impacts at Class I areas, the general trend in the region shows little change in visibility impacts at the Badlands National Park and Jim Bridger Wilderness Area from 1989 to 2005 (figure 3.4-2).

Predicted impacts from baseline year (2004) and projected 2015 and 2020 emissions were modeled for four air quality criteria pollutants (NO<sub>2</sub>, SO<sub>2</sub>, PM<sub>2.5</sub>, and PM<sub>10</sub>), along with changes in air quality-related values at Class I and identified sensitive areas. For regulatory purposes, the Class I PSD evaluations are not directly comparable to the air quality permitting requirements, because the modeling effort does not identify or separately evaluate increment-consuming sources that would need to be evaluated under the PSD program. The cumulative impact

analysis focuses on changes in cumulative impacts, but not on a comparison to PSD-related evaluations, which would apply to specific sources.

Table 4-11 presents the modeled impacts on ambient air quality at the near-field receptors in Montana and Wyoming. Results shown represent the maximum impact at any point in each receptor group; data are provided for the baseline year (2004) analysis and for both coal production scenarios for 2015 and 2020. Peak impacts occur at isolated receptors and are likely due to unique source-receptor relationships. The model results should not be construed as predicting an actual exceedance of any standard, but are at best indicators of potential impacts.

The results of the modeling depict the anticipated changes under both the lower and upper development scenarios (table 4-11). For the Wyoming near-field receptors, the predicted impact of the 24-hour PM<sub>10</sub> and PM<sub>2.5</sub> concentrations show localized exceedances in the region of the NAAQS for the baseline year (2004), as well as for both development scenarios for 2015 and 2020. Both 2020 development scenarios show the concentration increases by a factor of 2.5 relative to the base year for these two parameters. Additionally, while down about 10% from 2015, the 2020 development shows a 20% increase of annual PM<sub>10</sub> and PM<sub>2.5</sub> concentrations at peak Wyoming near-field receptors relative to the base year. This level of increase for 2020 predicted modeled exceedances of annual standards for PM<sub>2.5</sub> that year. Impacts of NO<sub>2</sub> and SO<sub>2</sub> emissions are predicted to be below the NAAQS and WAAQS at the Wyoming near-field receptors.

Based on the modeling results, impacts at Montana near-field receptors would be in compliance with the NAAQS and the Montana Ambient Air Quality Standard (MAAQS) for all pollutants and averaging periods, with one exception (table 4-11). Importantly, the 1-hour NO<sub>2</sub> concentrations at Montana near-field receptors for all years and development scenarios were predicted to exceed the NAAQS. Those concentrations were also predicted to exceed the MAAQS in 2015 at isolated locations because of CBNG development in Wyoming; however, with the anticipated southward progression of the CBNG wells, the 1-hour NO<sub>2</sub> concentrations in 2020 are predicted to remain below the MAAQS. The southward progression of the CBNG wells also contributes to a predicted slight decrease in 2020 of impacts for annual NO<sub>2</sub>, PM<sub>10</sub> and PM<sub>2.5</sub> relative to the baseline year. Although large percentage increases were predicted in SO<sub>2</sub> impacts by 2020, especially for 1- and 3-hour monitoring, those levels would remain below the national and state ambient standards for all pollutants in the Montana near-field.

As discussed in section 3.4.2.2, modeling tends to over-predict the 24-hour impacts of surface coal mining and, as a result, the WDEQ does not consider short-term PM<sub>10</sub> modeling to be an accurate representation of short-term impacts. In view of this, a memorandum of agreement between the WDEQ and EPA Region VIII, dated January 24, 1994, allows the WDEQ to conduct monitoring in lieu of short-term modeling for assessing coal-mining-related impacts in the PRB. This agreement also requires “best available work practice” mitigation measures in all coal mining permits (WDEQ and EPA 1994). The monitored exceedances at surface coal mines in the Wyoming PRB and the measures that the WDEQ has implemented or is proposing to implement to prevent future exceedances of the PM<sub>10</sub> NAAQS are discussed in chapter 3, sections 3.4.2.1 and 3.4.2.3.

4.0 Cumulative Environmental Consequences

Table 4-11. Projected Maximum Potential Near-Field Impacts ( $\mu\text{g}/\text{m}^3$ )

Pollutant	Averaging Time	Base Year (2004) Impacts	2015 Lower Coal Development Scenario Impacts	2015 Upper Coal Development Scenario Impacts	2020 Lower Coal Development Scenario Impacts	2020 Upper Coal Development Scenario Impacts	National AAQS	Wyoming AAQS	Montana AAQS	PSD Class II Increments
Wyoming Near-Field										
NO <sub>2</sub>	Annual	31.3	46.7	47.4	30.5	30.6	100	100	— <sup>a</sup>	25
SO <sub>2</sub>	Annual	15.3	16.2	16.2	16.4	16.5	80	60	—	20
	24-hour	112.3	119.6	119.6	143.3	143.3	365	260	—	91
	3-hour	462.0	814.1	814.1	936.7	936.7	1,300	1,300	—	512
PM <sub>2.5</sub>	Annual	13.4	<b>18.7</b>	<b>21.4</b>	<b>16.3</b>	<b>16.3</b>	15	15	—	—
	24-hour	<b>87.6</b>	<b>179.5</b>	<b>179.5</b>	<b>218.4</b>	<b>218.4</b>	35	35	—	—
PM <sub>10</sub>	Annual	38.4	<b>53.5</b>	<b>61.0</b>	46.6	46.6	—	50 <sup>b</sup>	—	17
	24-hour	<b>250.4</b>	<b>512.8</b>	<b>512.9</b>	<b>624.1</b>	<b>624.3</b>	150	150	—	30
Montana Near-Field										
NO <sub>2</sub>	Annual	3.3	6.5	6.5	2.5	2.6	100	—	100	25
	1-hour	<b>409.0</b>	<b>826.3</b>	<b>826.4</b>	<b>440.1</b>	<b>442.7</b>	188.1	—	564	—
SO <sub>2</sub>	Annual	1.6	1.7	1.7	3.0	3.1	80	—	80	20
	24-hour	16.1	16.5	16.6	24.7	27.1	365	—	365	91
	3-hour	65.0	66.5	66.5	138.9	138.9	1,300	—	1,300	512
	1-hour	162.9	166.6	166.6	237.0	259.1	—	—	1,300	—
PM <sub>2.5</sub>	Annual	1.0	1.8	1.9	0.9	0.9	15	—	15	—
	24-hour	10.2	15.4	20.6	10.2	10.2	35	—	35	—
PM <sub>10</sub>	Annual	2.8	5.2	5.3	2.5	2.6	—	—	50	17
	24-hour	29.1	44.0	58.5	29.3	29.3	150	—	150	30

$\mu\text{g}/\text{m}^3$  = microgram per cubic meter; AAQS = Ambient Air Quality Standards; PSD = prevention of significant deterioration; NO = nitrogen oxide; SO<sub>2</sub> = sulfur dioxide; PM<sub>10</sub> = particulate matter measuring 10 microns or less in diameter; PM<sub>2.5</sub> = particulate matter measuring 2.5 microns or less in diameter

<sup>a</sup> No standard or increment.

<sup>b</sup> The EPA has revoked the NAAQS annual PM<sub>10</sub> standard of 50  $\mu\text{g}/\text{m}^3$ , but that standard is still effective for Wyoming until it enters into rulemaking to revise the state AAQS.

**Bold values** indicate projected exceedance of national and/or state ambient air quality standards.

Source: 2009 update to the Task 3A Report (BLM 2009d).

The maximum modeled impact on the annual PM<sub>2.5</sub> level is projected to be above the standard (15 µg/m<sup>3</sup>) at near-field receptors in Wyoming for the lower and upper coal production scenarios for both 2015 and 2020. Annual PM<sub>10</sub> levels are projected to be above the standard (50 µg/m<sup>3</sup>) at near-field receptors in Wyoming for 2015, and then to fall back below the standard for the 2020 lower and upper coal production scenarios. The EPA has revoked the NAAQS annual PM<sub>10</sub> standard of 50 µg/m<sup>3</sup>, but until Wyoming enters into rulemaking to revise the WAAQS, that standard is still effective. The WDEQ issues air quality permits for coal mining. That agency cannot issue any permit that violates ambient air quality standards. As noted, impacts of NO<sub>2</sub> and SO<sub>2</sub> emissions are predicted to be below the NAAQS and WAAQS at all Wyoming near-field receptors for all years. A large portion of the impacts for all scenarios would be associated with coal-related sources, although non-coal sources would contribute a notable portion of the impact.

Table 4-12 lists the three Class I areas and two Class II areas where the modeled impacts are the greatest. The table compares the modeled impacts to the PSD Class I and sensitive Class II increment levels. However, it must be noted that this modeling analysis did not separate PSD increment-consuming sources from those that do not consume increment. The PSD-increment comparison is provided for informational purposes only and cannot be directly related to a regulatory interpretation of PSD increment consumption.

Most modeled impacts for the four pollutants (NO<sub>2</sub>, SO<sub>2</sub>, PM<sub>2.5</sub>, and PM<sub>10</sub>) analyzed are below the Class I increment levels in all coal development scenarios (base year, lower and upper 2015 and 2020). At the Northern Cheyenne Indian Reservation and Wind Cave National Park, impacts are slightly above the Class I comparative increment levels for 24-hour PM<sub>10</sub> in all years (baseline, 2015, 2020) and development scenarios (table 4-12). Those impacts are also above the Class I increments at the Badlands National Park for both scenarios in 2020. Additionally, the SO<sub>2</sub> impacts at the Northern Cheyenne Indian Reservation for the 3-hour and 24-hour averaging period exceed the Class I PSD increment levels for one or both development scenarios in 2020. In the other Class I areas, only the modeled 24-hour SO<sub>2</sub> impacts at Theodore Roosevelt National Park and Fort Peck Indian Reservation, and 3-hour SO<sub>2</sub> impacts at Theodore Roosevelt National Park are above the PSD increment levels for the 2020 development scenarios. However, the predicted exceedances for these areas are related to sources outside the PRB study area, consequently, neither area is included in table 4-12.

In the sensitive Class II areas, the only modeled exceedances of the Class II PSD increments relate to the 24-hour PM<sub>10</sub> levels at the upper 2015 development scenario in the Cloud Peak Wilderness Area and Crow Indian Reservation. The modeled annual NO<sub>2</sub> impacts at those two areas are projected to increase by a factor of 2 to 4, respectively, in 2020 as a result of projected CBNG and coal hauling activities. However, modeling results for all sensitive Class II areas are far below PSD increment levels for all pollutants for both 2020 development scenarios.

4.0 Cumulative Environmental Consequences

Table 4-12. Maximum Predicted PSD Class I and Sensitive Class II Area Impacts ( $\mu\text{g}/\text{m}^3$ )

Location	Pollutant	Averaging Period	Base Year (2004) Impacts	2015 Lower Coal Development Scenario	2015 Upper Coal Development Scenario	2020 Lower Coal Development Scenario	2020 Upper Coal Development Scenario	PSD Class I/II Increments	
Class I Areas <sup>a</sup>									
Northern Cheyenne Indian Reservation	NO <sub>2</sub>	Annual	0.4	0.6	0.9	0.8	1.1	2.5	
		Annual	0.5	0.6	0.7	1.1	1.3	2	
	SO <sub>2</sub>	24-hour	3.1	3.4	3.4	7.1	12.8	5	
		3-hour	9.4	9.6	9.6	23.6	39.7	25	
	PM <sub>2.5</sub>	Annual	0.3	0.5	0.5	0.4	0.5	— <sup>b</sup>	
		24-hour	3.4	5.1	5.1	4.5	4.6	—	
	PM <sub>10</sub>	Annual	0.9	1.5	1.5	1.2	1.5	4	
		24-hour	9.6	14.4	14.6	12.9	13.2	8	
	Badlands National Park	NO <sub>2</sub>	Annual	0.1	0.0	0.0	0.2	0.2	2.5
			Annual	0.5	0.2	0.2	0.6	0.2	2
SO <sub>2</sub>		24-hour	3.6	3.1	3.1	4.0	4.0	5	
		3-hour	8.1	6.3	6.3	8.2	8.2	25	
PM <sub>2.5</sub>		Annual	0.2	0.1	0.1	0.3	0.3	—	
		24-hour	2.1	1.6	1.6	3.0	3.1	—	
PM <sub>10</sub>		Annual	0.7	0.2	0.2	0.9	1.0	4	
		24-hour	5.9	4.6	4.7	8.5	8.8	8	
Wind Cave National Park		NO <sub>2</sub>	Annual	0.2	0.3	0.3	0.3	0.3	2.5
			Annual	0.7	0.8	0.8	0.8	0.8	2
	SO <sub>2</sub>	24-hour	3.7	4.1	4.1	4.6	4.7	5	
		3-hour	7.0	7.4	7.4	7.5	7.7	25	
	PM <sub>2.5</sub>	Annual	0.4	0.5	0.5	0.5	0.5	—	
		24-hour	3.8	4.6	4.7	4.6	4.7	—	
	PM <sub>10</sub>	Annual	1.0	1.3	1.4	1.4	1.4	4	
		24-hour	10.9	13.3	13.6	13.0	13.3	8	

Table 4-12. Continued

Location	Pollutant	Averaging Period	Base Year (2004) Impacts	2015 Lower Coal Development Scenario	2015 Upper Coal Development Scenario	2020 Lower Coal Development Scenario	2020 Upper Coal Development Scenario	PSD Class I/II Increments	
Sensitive Class II Areas <sup>c</sup>									
Cloud Peak Wilderness Area	NO <sub>2</sub>	Annual	0.06	0.6	0.7	0.12	0.12	25	
		Annual	0.2	0.6	0.6	0.3	0.3	20	
	SO <sub>2</sub>	24-hour	2.0	3.7	4.0	2.5	2.5	91	
		3-hour	8.0	14.3	14.3	8.9	9.0	512	
	PM <sub>2.5</sub>	Annual	0.2	0.5	0.7	0.2	0.2	—	
		24-hour	2.6	7.8	11.9	3.2	3.39	—	
	PM <sub>10</sub>	Annual	0.5	1.6	2.1	0.7	0.7	17	
		24-hour	7.4	22.3	<b>34.1</b>	9.1	9.3	30	
	Crow Indian Reservation	NO <sub>2</sub>	Annual	0.9	1.4	1.7	3.6	4.2	25
			Annual	2.3	2.3	2.3	2.4	2.7	20
SO <sub>2</sub>		24-hour	14.4	14.6	14.6	14.8	14.8	91	
		3-hour	76.8	77.0	77.0	77.0	77.0	512	
PM <sub>2.5</sub>		Annual	0.8	1.0	1.4	0.8	0.8	—	
		24-hour	7.2	9.4	14.3	7.2	7.2	—	
PM <sub>10</sub>		Annual	2.2	2.9	4.1	2.3	2.4	17	
		24-hour	20.5	26.9	<b>40.7</b>	20.6	20.6	30	

PSD = prevention of significant deterioration;  $\mu\text{g}/\text{m}^3$  = microgram per cubic meter; NO<sub>2</sub> = nitrogen dioxide; SO<sub>2</sub> = sulfur dioxide; PM<sub>10</sub> = particulate matter measuring 10 microns or less in diameter; PM<sub>2.5</sub> = particulate matter measuring 2.5 microns or less in diameter

<sup>a</sup> Pristine attainment area.

<sup>b</sup> No standard or increment.

<sup>c</sup> Certain federal assets with Class II status for which air quality and/or visibility are valued resources.

**Bold values** indicate exceedance of PSD class I or II increment.

Source: 2009 update to the Task 3A Report (BLM 2009d).

Table 4-13 provides a detailed listing of visibility impacts for all analyzed Class I and sensitive Class II areas. For the baseline year, the maximum visibility impacts at Class I areas were determined to be at the Northern Cheyenne Indian Reservation in Montana and at Wind Cave and Badlands National Park in South Dakota. For these locations, the base year showed more than 200 days of impacts with more than 10% light extinction (i.e., reduction in visibility). A 10% change in light extinction corresponds to 1.0 dv, which is an expression of visibility impairment. A change in visibility of 1.0 dv represents a “just noticeable change” by an average person under most circumstances. Increasing dv values represent proportionately larger perceived visibility impairment.

To provide a basis for discussing the modeled visibility impacts resulting from the projected increased production under the lower and upper coal production scenarios for 2015 and 2020, the visibility impacts for the base year of 2004 were subtracted from the modeled results for those two years. Table 4-13 shows the number of additional days that the projected impacts were greater than 1.0 dv (10% change in light extinction) for each site under the upper and lower coal production scenarios for each modeled year. Using Badlands National Park as an example, the analysis showed 218 days with impacts greater than 1.0 dv in 2004. Under the 2015 and 2020 coal production scenarios, the modeling analysis projects an additional 26 and 44 days, respectively, with impacts greater than 1.0 dv under both the lower and upper development scenarios. That equates to a total of 244 to 262 days with impacts greater than 1.0 dv, respectively.

Both the 2015 and 2020 modeled visibility impacts at the identified Class I areas (table 4-13) continue to show a similar pattern as exhibited for the baseline year (2004), with the highest number of days with a greater than 10% change in visibility predicted at the three most affected Class I areas. All but four of the sensitive Class II areas had more than 100 days with greater than a 10% change during the base year. The most significant visibility changes to sensitive Class II areas in both 2015 and 2020 are predicted for Mount Rushmore National Monument, followed by Black Elk Wilderness Area (table 4-13). Class II areas do not have any visibility protection under federal or state law.

For acid deposition, all predicted impacts are below the deposition threshold values for both nitrogen and sulfur compounds. There are substantial percentage increases in deposition under the lower and upper coal production scenarios for 2015; however, impacts remain well below the nitrogen and sulfur levels of concern (1.5 and 5.0 kilograms per hectare per year, respectively). The acid-neutralizing capacity of sensitive lakes also was analyzed, and results are summarized in table 4-14. The base year study indicated that none of the lakes had predicted significant impacts except Upper Frozen Lake; however, the lower and upper development scenarios for both 2015 and 2020 show an increased impact at Florence Lake, leading to an impact above the 10% change in acid-neutralizing capacity. Impacts also are predicted to be above 1 microequivalent per liter for Upper Frozen Lake.

Table 4-13. Modeled Change in Visibility Impacts at Class I and Sensitive Class II Areas

Location	Base Year (2004) No. of Days >10% Change in Visibility	Coal Development Scenario			
		2015 Lower	2015 Upper	2020 Lower	2020 Upper
		Change in No. of Days >10% in visibility			
Class I Areas <sup>a</sup>					
Badlands National Park	218	26	26	44	44
Bob Marshall Wilderness Area	8	0	0	0	0
Bridger Wilderness Area	144	2	2	5	5
Fitzpatrick Wilderness Area	91	2	2	6	6
Fort Peck Indian Reservation	105	10	10	20	21
Gates of the Mountain Wilderness Area	55	0	0	4	4
Grand Teton National Park	70	2	2	6	6
North Absaroka Wilderness Area	61	3	3	8	8
North Cheyenne Indian Reservation	243	32	47	59	60
Red Rock Lakes	42	2	2	3	3
Scapegoat Wilderness Area	27	1	1	2	2
Teton Wilderness Area	57	4	4	8	8
Theodore Roosevelt National Park	178	5	9	24	24
UL Bend Wilderness Area	77	8	10	18	18
Washakie Wilderness Area	83	5	5	8	8
Wind Cave National Park	262	18	19	28	31
Yellowstone National Park	84	2	2	5	5

4.0 Cumulative Environmental Consequences

Table 4-13. Continued

Location	Base Year (2004) No. of Days >10% Change in Visibility	Coal Development Scenario			
		2015 Lower	2015 Upper	2020 Lower	2020 Upper
		Change in No. of Days >10% in visibility			
Sensitive Class II Areas <sup>b</sup>					
Absaroka Beartooth Wilderness Area	101	2	3	10	10
Agate Fossil Beds National Monument	251	20	20	26	26
Big Horn Canyon National Rec. Area	331	1	3	1	1
Black Elk Wilderness Area	236	34	36	47	47
Cloud Peak Wilderness Area	126	18	18	29	30
Crow Indian Reservation	360	4	4	3	3
Devils Tower National Monument	274	25	25	31	32
Fort Belknap Indian Reservation	66	6	7	14	15
Fort Laramie National Historic Site	260	10	10	15	16
Jedediah Smith Wilderness Area	79	1	1	3	5
Jewel Cave National Monument	261	19	21	36	37
Lee Metcalf Wilderness Area	97	2	2	2	2
Mount Naomi Wilderness Area	51	1	1	1	1
Mount Rushmore National Monument	222	36	36	49	52
Popo Agie Wilderness Area	139	4	4	6	6
Soldier Creek Wilderness Area	268	18	18	19	19
Wellsville Mountain Wilderness Area	130	10	10	17	17
Wind River Indian Reservation	217	2	5	9	10

<sup>a</sup> Pristine attainment area.

<sup>b</sup> Certain federal assets with Class II status for which air quality and/or visibility are valued resources.

Source: 2009 update to the Task 3A Report (BLM 2009d).























































































































































#### 4.2.14.2 Cumulative Effects of Combustion of PRB Coal by Power Plants

Historically, the coal mined in the PRB has been used as one of the sources of fuel to generate electricity in power plants located nationwide. Relatively little PRB coal, about 2%, is burned in Wyoming.

In 2008, Wyoming coal went to 36 states besides Wyoming, although it can also be shipped overseas. Over 95% of coal produced in the PRB is sold in an open market where coal is purchased on short-term contracts or spot prices based on a coal feed stock that is suitable for each buyer's power generating facility. Power plant buyers attempt to buy coal from suppliers at the most economical prices that meet their needs. PRB coal has competed well in this market because of its low sulfur content, providing a way for electric generators to achieve acid rain (SO<sub>2</sub>) reduction requirements as well as lowering competitive mining costs when compared to delivered costs of coal from other coal-producing areas.

Wyoming coal production has increased more rapidly than other domestic coal. Coal coming out of the PRB is mined using surface mining methods which are generally safer, less labor intensive, and are easier to reclaim than underground mining. Rural rangelands are the areas that are predominately mined; they are reclaimed according to WDEQ's standards (section 3.9.4). PRB coal reserves are in thick seams, resulting in more production from the same disturbance area, and lower mining and reclamation costs.

During the coal leasing EIS process, it is difficult to predict who might purchase future PRB coal, how it would be used, and where it might be transported to. In the North American Electric Reliability Corporation power regions where PRB coal is sold, coal use ranges from 74.2% in the upper Midwest, to 15.6% in the northeast United States (EPA 2007d).

Some methods of generating electricity (e.g., natural gas, nuclear, hydroelectric, solar, wind, and geothermal resources) result in fewer GHG emissions than burning coal. The demand for power is increasing in the United States and throughout the world. According to a recent report by the North American Electric Reliability Council, peak demand for electricity in the United States is expected to double in the next 22 years (Associated Press 2007). Many developing countries, including China and India, rely heavily on coal to meet their rapidly increasing power demands, as coal is more economical and more available than other sources of electrical generation. Coal-burning power plants currently supply about 44.5% of the electric power generated in the United States as of 2009 (U.S. Energy Information Administration 2009c). The demand for power is increasing in the United States and throughout the world. In the International Energy Outlook 2010, the EIA is projecting electrical generation from coal by the year 2035 to be 44% (U.S. Energy Information Administration 2010).

The regulatory mechanisms proposed under the Climate Security Act of 2008, as well as regulation of pollutants under the CAA, are imposed at the point when coal is burned and converted to electric energy.

Coal-fired power plants have been identified as principal sources of anthropogenic CO<sub>2</sub> emissions. The Task 2 analysis assumed that all PRB coal is part of the total U.S. consumption for electric generation. Under that assumption, CO<sub>2</sub> emissions attributed to PRB coal were calculated based on the percentage of coal production in that area compared to total coal production in the United States. This approach provided estimates of CO<sub>2</sub> emissions from the

use of the PRB coal to produce electricity under upper and lower projections for coal production scenarios in that region.

U.S. coal production increased from 1,029.1 million tons in 1990, when the Powder River Federal Coal Region was decertified, to 1,161.4 million tons in 2006, an increase of 12.9% (U.S. Department of Energy 2007a). Wyoming coal production increased from 184.0 million tons in 1990 to 444.9 million tons in 2006, an increase of 242% (Wyoming Department of Employment 1990 and 2006). The share of electric power generated by burning coal was consistently around 50% during the 16 years between 1990 and 2006. The percentage of total U.S. CO<sub>2</sub> emissions related to coal consumption was consistently around 36% during that same time. The percentage of U.S. CO<sub>2</sub> emissions related to the coal electric power sector increased from about 30% in 1990 to about 33% in 2006 (U.S. Energy Information Administration 2009d).

In 2008, the Wyoming PRB coal mines produced approximately 451.7 million tons of coal. Using factors derived from laboratory analyses, an estimated 749.6 million metric tons of CO<sub>2</sub> would be generated from the combustion of all of this coal before CO<sub>2</sub> reduction technologies were applied. This number is based on an average Btu value of 8,600 per pound of Wyoming coal using a CO<sub>2</sub> emission factor of 212.7 pounds of CO<sub>2</sub> per million Btu (U.S. Energy Information Administration 1994). The estimated 749.6 million metric tons of CO<sub>2</sub> represents approximately 35.3% of the estimated 2,125.2 million metric tons of U.S. CO<sub>2</sub> emissions from coal combustion in 2008 (U.S. Energy Information Administration 2009d). In 2008, Wyoming PRB mines accounted for approximately 38.5% of the coal produced in the U.S. (U.S. Energy Information Administration 2009a).

The EIA's 2008 Emissions of GHGs in the U.S. report (U.S. Energy Information Administration 2009d) and EIA's 2008 U.S. Coal Report (U.S. Energy Information Administration 2009a) report the following.

- CO<sub>2</sub> emissions represent about 83% of the total U.S. GHG emissions.
- Estimated CO<sub>2</sub> emissions in the United States totaled 5,839.3 million metric tons in 2008, which was a 1.5% decrease from 2006 (which was 5,928.7 million metric tons).
- Estimated CO<sub>2</sub> emissions from the electric power sector in 2008 totaled 2,359.1 million metric tons, or about 40.6% of total U.S. energy-related CO<sub>2</sub> emissions in 2008 (which was 5,814.4 million metric tons).
- Estimated CO<sub>2</sub> emissions from coal electric power generation in 2008 totaled 1,945.9 million metric tons or about 33.5% of total energy-related CO<sub>2</sub> emissions and about 82.5% of CO<sub>2</sub> emissions from the U.S. electric power sector in 2008.
- Coal production from the Wyoming PRB represented approximately 43.4% of the coal used for power generation in 2008, which means that combustion of Wyoming PRB coal to produce electric power was responsible for about 12.8% of the estimated U.S. CO<sub>2</sub> emissions in 2008.

As discussed earlier in this chapter, the Task 2 Report projects coal development for 2010, 2015, and 2020. Due to the variables associated with future coal production, two projected coal production scenarios (representing an upper and a lower production level) were developed to bracket the most likely foreseeable regional coal production level. In the low scenario, the percentage of coal use for electric generation would stay about the same, assuming that all forms of electric generation would grow at a proportional rate to meet forecast electric demand. In the high scenario, percentage of coal use would also remain about the same, but with PRB coal displacing coal from other domestic coal regions. Table 4-37 shows the estimated annual CO<sub>2</sub> emissions that would be produced from the combustion of all of this coal (before CO<sub>2</sub> reduction technologies are applied).

**Table 4-37. Estimated Annual CO<sub>2</sub> Emissions from Projected PRB Coal Production Levels According to Task 2 Report**

Projected Coal Production Scenario	Year	Coal Production Rate (million U.S. tons per year) <sup>a</sup>	CO <sub>2</sub> Emissions (million metric tons per year) <sup>b</sup>
Lower	2010	411	682
	2015	467	775
	2020	495	821
Upper	2010	479	795
	2015	543	901
	2020	576	956

<sup>a</sup> US tons (2000 pounds per ton).  
<sup>b</sup> Metric tons (2204 pounds per ton).  
 Source: Updated Task 2 Report (BLM 2009c).

In the following analysis, the contribution of the pending LBAs (table 1-2) to cumulative effects on the environment by historic and projected development activity is evaluated. To do this, it is assumed that coal mining would proceed in accordance with existing permit conditions and would be sold to coal users in response to forecasts of demand. Historically these users have been electric utilities in the United States, although there is potential for sales outside the country. This coal market is open and competitive and users can buy from the most cost effective suppliers that meet their needs.

The BLM does not determine the destination of this coal, and the use of the coal is determined by the coal consumer. The electric utilities where this coal has historically been used are located throughout the United States and have a variety of coal combustion technologies and emission control systems. These systems are licensed by the appropriate regulatory authorities in their locale and operate under necessary permit requirements in compliance with regulation.

Table 4-38 shows the estimated cumulative annual CO<sub>2</sub>e emissions produced by all mines in the PRB that currently have LBAs pending (listed in table 1-2). The cumulative emissions calculated are those associated with the actual mining operations and not from the combustion of the coal produced and sold on the open coal market.

**Table 4-38. Estimated Annual CO<sub>2</sub> Equivalent Emissions<sup>a</sup> from Coal Production at PRB Mines with Pending LBAs**

Source	2007	With LBA Tracts
Four South Gillette Area Coal Mines/Four LBA Tracts	0.716	1.182
Three Wright Area Coal Mines/Six LBA Tracts	1.245	2.503
Antelope Mine/West Antelope II Tract	0.225	0.348
Buckskin Mine/Hay Creek II Tract	0.197	0.197
Total	2.535	4.229

LBA = lease by application

<sup>a</sup> CO<sub>2</sub>e in million metric tons.

Source: Love pers. comm.; Jones & Stokes 2009, WWC Engineering 2009.

Individual LBA tracts are addressed in the following EISs: West Antelope II Coal Lease Application FEIS (BLM 2008e); South Gillette Area Coal Lease Applications FEIS (BLM 2009h); Wright Area Coal Lease Applications FEIS (BLM 2010); and Hay Creek II Coal Lease Application FEIS (this document).

Under the Proposed Action and Alternative 2, the Buckskin Mine anticipates producing coal included in the proposed tract or alternative tract configuration, respectively, at currently permitted levels using existing production and transportation facilities. Estimates of GHG emissions resulting from current and projected operations at the mine under the Proposed Action and Alternative 2 are included in section 3.18.3.

The CO<sub>2</sub> emissions from coal purchased from the Buckskin Mine and used to generate electricity in other states would be extended; the mine does not sell coal to any foreign entities at this time. Table 4-39 shows the current (No Action) average annual coal production for the Buckskin Mine and the estimated CO<sub>2</sub> emissions related to burning coal at that existing level of production. The estimated annual CO<sub>2</sub> emissions that would be produced from burning coal recovered from the proposed tract and from an alternative tract configuration under Alternative 2 are also shown. Those estimates are based on the average current rate of annual coal production, which is not expected to change under either action alternative, and the assumption that mining would occur at that maximum permitted level until all coal resources in the leased tract are depleted. As expected, the estimate for total CO<sub>2</sub> emissions associated with burning new coal reserves would be greatest under Alternative 2 because of the larger potential tract size and longer mine life. Under this alternative, the Buckskin Mine could extend production by up to six years. In contrast, the average annual estimate for CO<sub>2</sub> emissions under Alternative 2 would be slightly lower than under the Proposed Action.

**Table 4-39. Estimated Annual CO<sub>2</sub> Emissions Produced from Combustion of Coal Produced from the Proposed Tract or BLM Study Area**

Applicant Mine/LBA Tract	Current (No Action) and Anticipated Average Annual Coal Production by Applicant Mine <sup>a</sup> (million tons per year)	CO <sub>2</sub> Emissions Related to Annual Coal Production <sup>b</sup> (million metric tons)	Recoverable Coal Added under Proposed Action <sup>a</sup> (million tons)	Mine Life Added under Proposed Action <sup>a</sup> (years)	CO <sub>2</sub> Emissions Added by Proposed Action <sup>b</sup> (million metric tons)		Recoverable Coal Added under Alternative 2 <sup>a</sup> (million tons)	Mine Life Added under Alternative 2 <sup>a</sup> (years)	CO <sub>2</sub> Emissions Added by Alternative 2 <sup>b</sup> (million metric tons)	
					Total for Proposed Tract	Average per Year for Proposed Tract			Total for BLM Study Area	Average per Year for BLM Study Area
Buckskin/Hay Creek II	25.0	41.5	54.1	2	89.8	44.9	149.7	6	Up to 248.4	41.4

<sup>a</sup> Anticipated coal production rates at the Buckskin Mine, coal tonnages within the proposed tract and BLM study area, and anticipated number of years added to the life of the mine under each alternative are addressed in chapter 2.

<sup>b</sup> Determined using emission factor of 1.659 metric tons CO<sub>2</sub>/ton of coal burned (U.S. Energy Information Administration 1994).

Despite these estimates, the actual level of CO<sub>2</sub> emissions produced from burning coal recovered from the proposed tract or an alternative tract configuration under Alternative 2 cannot be predicted with complete accuracy due to uncertainties about emission limits that would be in place when the new coal is mined, as well as where and how that coal would be used. As shown under the No Action Alternative in table 2-4, the Buckskin Mine projects that, after 2008, approximately 14 years of currently permitted mine life remains. More rapid improvements in technologies that provide for less CO<sub>2</sub> emissions, new CO<sub>2</sub> mitigation requirements, or an increased rate of voluntary CO<sub>2</sub> emissions reduction programs could result in significantly lower CO<sub>2</sub> emissions levels than are projected here.

The Buckskin Mine produced approximately 25 million tons of coal in 2008, or about 4% of the coal produced in the Wyoming PRB that year. Combustion of those 25 million tons of coal to produce electricity generated approximately 41.5 million metric tons of CO<sub>2</sub> emissions, or about 0.6% of the total estimated anthropogenic CO<sub>2</sub> emissions produced in the United States in 2008 (about approximately 7,052.6 million metric tons) (U.S. Department of Energy 2009d). Under the No Action Alternative, CO<sub>2</sub> emissions attributed to burning coal produced by the mine would continue at this approximate level for up to 14 years beyond 2008, while the mine recovers the remaining estimated 460.9 million tons of currently leased coal reserves.

Selection of the No Action Alternative would probably not result in a decrease of U.S. CO<sub>2</sub> emissions attributed to coal mining and coal-burning power plants in the longer term, because multiple other sources of coal are available. Although this coal does not have the cost, environmental, or safety advantages of PRB coal, it could supply the demand beyond the time that the Buckskin Mine completes coal recovery in its existing leases.

In 2006, transportation sources accounted for approximately 29% of total U.S. GHG emissions (EPA 2008c). This is the fastest growing source of U.S. GHGs, accounting for 47% of the net

increase in total U.S. emissions since 1990. Transportation is also the largest end-use source of CO<sub>2</sub>, which is the most prevalent GHG (EPA 2008c).

CO<sub>2</sub> is not the only GHG of concern. Methane is a component of CBNG that is released into the atmosphere when coal is mined. The other major sources of U.S. methane emissions are from agriculture and waste management. The EIA (2007a and 2007b) reports the following.

- Anthropogenic methane emissions in the U.S. totaled 737.4 million metric tons CO<sub>2</sub>e in 2008 and 722.7 million metric tons CO<sub>2</sub>e in 2007.
- Methane emissions from coal mining across the nation were estimated at 82.0 million metric tons CO<sub>2</sub>e, or approximately 11.1% of the U.S. total anthropogenic methane emissions in 2008.
- Surface coal mining operations were estimated to be responsible for methane emissions of about 15.7 million metric tons of CO<sub>2</sub>e in 2008 in the United States. This represents about 2.1% of the estimated anthropogenic methane emissions in 2008, and about 19.1% of the estimated methane emissions attributed to coal mining of all types.
- The Wyoming PRB produced approximately 55.5% of the coal mined in the United States in 2008 using surface mining techniques, which means that Wyoming PRB surface coal mines were responsible for approximately 1.7% of the estimated U.S. anthropomorphic methane emissions that year. The Buckskin Mine contributed about 4% of the Wyoming PRB coal production in 2006. Since 1990, when the BLM began using the LBA process, total U.S. anthropogenic methane emissions declined from 783.5 million metric tons CO<sub>2</sub>e to 737.4 million metric tons CO<sub>2</sub>e in 2008. Total coal mining related emissions declined from 106.4 million metric tons CO<sub>2</sub>e to 82.0 million metric tons CO<sub>2</sub>e during the same period. The EIA attributes the overall decrease in emissions of methane to increases in coal production from surface coal mines that produce relatively little methane (U.S. Energy Information Administration 2009d).

CBNG is commercially produced on a large scale by oil and gas operators from wells located within and near the Hay Creek II general analysis area. CBNG that is not recovered prior to mining is vented to the atmosphere during the mining process. Selection of the No Action Alternative would allow more complete recovery of the CBNG from the general analysis area in the short term (roughly 14 years), during the time that the applicant mine's currently leased coal is being recovered. Under Alternative 2, a large portion of the CBNG resources in the BLM study area would be recovered prior to mining as discussed in Section 3.3.2.2. Selection of the No Action Alternative would not likely directly decrease U.S. methane emissions attributed to coal mining in the long term because multiple other sources of coal are available that could supply the coal demand beyond the time that the Buckskin Mine recovers the coal in its existing leases.

Nitrous oxide is the other GHG of concern that is associated with coal mining; however, the largest source in the United States is agricultural (about 76% comes from fertilization of soils and about 24% from management of animal waste) (U.S. Energy Information Administration 2009d).

Although the effects of GHG emissions and other contributions to global climate change can be estimated, given the current state of science it is impossible to determine what effect any amount

of GHG emissions from an activity might have on global warming, climate change, or the environmental effects stemming from it. Thus, it is not currently possible to associate any particular action and its specific project-related emissions with the creation or mitigation of any specific climate-related effects at any given time or place. However, certain actions and the effects of that action may contribute to the effects of climate change, even though specific climate-related environmental effects cannot be directly attributed to them.

#### 4.2.14.3 U.S. Actions and Strategies to Address Greenhouse Gas Emissions

Potential regulatory policies to address climate change are in various stages of development at the federal, state, and regional levels (U.S. Energy Information Administration 2009e). A number of bills have been introduced in the U.S. Congress related to global climate change. At this time, no national policy or law is in place to regulate GHG emissions.

The Lieberman-Warner Climate Security Act, which was introduced in October 2007 by Senators Joseph I. Lieberman (ID-CT) and John W. Warner (R-VA), would establish a cap-and-trade within the United States. In short, the “cap” would set a legal limit on the quantity of GHGs that a region can emit each year and “trade” would allow companies to exchange the permission (or permits) to emit GHGs. The cap would get tighter over time, and by 2050, emissions would be reduced by 63% below 2005 levels. The Senate Environment and Public Works Committee approved the bill in December, 2007 (<http://www.pewclimate.org>, accessed 12/21/2007). The bill was introduced in the Senate and read the first time on May 20, 2008. The Boxer-Lieberman-Warner substitute amendment to the Climate Security Act of 2008 was released by the Senate Environment and Public Works Committee on May 21, 2008. The bill was read a second time and placed on the Senate Legislative Calendar under General Orders, Calendar No. 742. In June 2008, the U.S. Senate voted to invoke cloture on the Boxer amendment but did not pass the cap-and-trade legislation.

On June 26, 2009, the U.S. House of Representatives passed The American Clean Energy and Security Act of 2009. The legislation includes a federal GHG emissions cap-and-trade program that would take effect in 2012. The declining emissions cap requires that total GHG emissions be 17% below 2005 levels by 2020 and 83% below 2005 levels by 2050. In November 2009, the Senate Environment and Public Works Committee passed a GHG cap-and-trade bill that borrows much from the House American Clean Energy and Security Act and tightens the GHG emissions cap to 20% below 2005 levels by 2020. Several other committees are expected to weigh in before the final bill is crafted and brought before the Senate floor (U.S. Energy Information Administration 2009d).

On April 2, 2007, in *Massachusetts v. EPA*, the U.S. Supreme Court found that GHGs are air pollutants covered by the CAA. The Court held that the administrator of the EPA must determine whether emissions of GHGs from new motor vehicles cause or contribute to air pollution that may endanger public health or welfare, or whether the science is too uncertain to make a reasoned decision. The court directed the EPA to review the latest science on climate change in order to make a determination. On April 17, 2009, the EPA administrator signed the Proposed Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the CAA. On December 7, 2009, the administrator signed two distinct findings regarding GHGs. The Administrator found that current and projected concentrations of the six key well-mixed GHGs—CO<sub>2</sub>, methane, nitrous oxide, hydrofluorocarbons (HFCs),

perfluorocarbons (PFCs), and sulfur hexafluoride (SF<sub>6</sub>)—in the atmosphere threaten the public health and welfare of existing and future generations and that the combined emissions of these GHGs from new motor vehicles contribute to climate change. The findings do not impose any emission reduction requirements but allow the EPA to finalize the GHG standards proposed earlier in 2009 (EPA 2009d). The agency can now regulate CO<sub>2</sub> as a pollutant and begin regulating GHG emissions from power plants, factories and major industrial polluters, although the details of that regulation have yet to be worked out. An endangerment finding under one provision of the CAA alone would not automatically trigger regulation under the entire Act.

Because of the Supreme Court's decision in 2007, the EPA drafted the Prevention of Significant Deterioration/Title V Greenhouse Gas Tailoring Rule. The draft rule, published in the Federal Register on October 27, 2009, limits the applicability of CO<sub>2</sub> emissions standards to new and modified sources that emit more than 25,000 metric tons CO<sub>2</sub>e annually, rather than applying the threshold of 250 tons per sources for triggering the regulation of criteria pollutants specified in Title V of the CAA. At the 25,000 metric tons CO<sub>2</sub>e annual level, the EPA expects that 14,000 large industrial sources, which are responsible for 70% of the U.S. GHG emissions, will be required to obtain Title V operating permits. That threshold would cover large power plants, refineries, and other large industrial operations (U.S. Energy Information Administration 2009d).

The EPA signed the Final Mandatory Reporting of Greenhouse Gases Rule on September 22, 2009 (EPA 2010). The rule requires suppliers of fossil fuels or industrial GHGs, manufacturers of vehicles and engines, and facilities that emit 25,000 metric tons or more per year of GHG emissions to submit annual reports to the EPA. The gases covered by the rule are CO<sub>2</sub>, nitrous oxide, HFCs, PFCs, SF<sub>6</sub>, and other fluorinated gases including nitrogen trifluoride (NF<sub>3</sub>) and hydrofluorinated ethers (HFE). The EPA's new reporting system will provide a better understanding of where GHGs are coming from and will guide development of the best possible policies and programs to reduce emissions. Reporters were required to begin monitoring their emissions on January 1, 2010, and the first annual emissions reports will be due in 2011 (EPA 2010).

The American Recovery and Reinvestment Act of 2009 ("The Stimulus Bill") was signed into law by President Obama on February 17, 2009, and under the Act, the DOE received \$36.7 billion to fund renewable energy, carbon capture and storage, energy efficiency, and smart grid projects. The projects are expected to provide reductions in both energy use and GHG emissions (U.S. Energy Information Administration 2009d).

Federal, state, and local governments are also developing programs and initiatives aimed at reducing energy use and emissions. The 2002 Clear Skies and Global Climate Change Initiative is a voluntary national program to reduce GHG emissions. There are federal tax incentives for energy efficiency and conservation, and some states have renewable energy and energy efficiency policies. Regional initiatives have started in the northeast (Northeast Regional Greenhouse Gas Initiative) as well as the Western Climate Initiative in the western states. It is not possible to predict how all of these programs would be melded into a national regulatory process if one were to be enacted.

A number of U.S. financial and corporate interests have acknowledged that enactment of federal legislation limiting the emissions of CO<sub>2</sub> and other GHGs seems likely (National Association of Regulatory Utility Commissioners 2007). There is uncertainty about anticipated CO<sub>2</sub> emission

limits and carbon capture/sequestration regulations. This has led some proponents to cancel or delay proposed projects that use existing and emerging technologies to produce electricity from coal (Bleizeffer 2007a and 2007b). Capacity planning decisions for new generating plants and investment behavior in the electric power sector are being affected by the potential impacts of policy changes that could be made to limit or reduce GHG emissions (U.S. Energy Information Administration 2009e).

Based on the coal-related and oil- and gas-related development in the PRB study area, future development of geologic carbon sequestration could occur in the area.

#### *4.2.14.4 Current and Future Energy Sources and Emissions of Greenhouse Gases in the U.S.*

The key determinant of energy consumption is population. Population influences demand for goods, services, housing, and travel. The population in the United States has increased by about 20% and energy consumption by a comparable 18% since 1990, with variations in energy use per capita depending on factors such as weather and the economy. To meet the nationwide consumer demand and requirement for energy, coal is burned in power plants to produce electricity. Coal is an important component of the U.S. energy supply partly because it is the most abundant domestically available fossil fuel (U.S. Geological Survey 2002b). One-quarter of the world's coal reserves are found within the United States; the energy content of U.S. coal resources exceeds that of all the world's known recoverable oil; and coal resources supply more than half of the electricity consumed by Americans (U.S. Energy Information Administration 2008c and U.S. Department of Energy 2009). Many countries are even more reliant on coal for their energy needs than is the United States. More than 70% of the electricity generated in China and India comes from coal (U.S. Geological Survey 2000). The value of coal is partially offset by the environmental impacts of coal combustion (U.S. Geological Survey 2000).

In the DOE's 2007 Annual Energy Outlook, energy-related CO<sub>2</sub> emissions were projected to grow by about 35% from 2006 to 2030 (U.S. Energy Information Administration 2007b). By comparison, the DOE's 2008 Annual Energy Outlook projected energy-related CO<sub>2</sub> emissions to grow by 16%, from 5,890 million metric tons in 2006 to 6,851 million metric tons in 2030 (U.S. Energy Information Administration 2008c). However, the DOE's 2009 Annual Energy Outlook projects energy-related CO<sub>2</sub> emissions to grow by 7%, from 5,991 million metric tons in 2007 to 6,414 million metric tons in 2030. The mix of sources for these generation projections include coal, natural gas, nuclear, liquids (petroleum), hydro-power, and non-hydro renewables (e.g., wind, solar). The most recent, lower projected emissions growth rate is the result of a slower demand growth combined with increased use of renewables and a declining share of electricity generation that comes from fossil fuels (U.S. Department of Energy 2009b).

Total U.S. anthropogenic GHG emissions in 2008 were 2.2% below the 2007 total. The decline in total emissions—from 7,209.8 million metric tons CO<sub>2</sub>e in 2007 to 7,052.6 million metric tons in 2008—was largely the result of a 177.8 million metric tons CO<sub>2</sub>e drop in CO<sub>2</sub> emissions. Emissions of other GHGs increased by small percentages, but those increases were more than offset by the drop in CO<sub>2</sub> emissions. The decrease in U.S. CO<sub>2</sub> emissions in 2008 resulted from higher energy prices, economic contraction, and lower demand for electricity (U.S. Energy Information Administration 2009e).

Energy-related CO<sub>2</sub> emissions dominate (about 81% in 2008) the total U.S. GHG emissions. Petroleum is the largest fossil fuel source for energy-related CO<sub>2</sub> emissions, contributing 41.9% of the total, whereas coal is the second-largest fossil fuel contributor, at 36.5%. Petroleum made up 44.6% of total fossil fuel energy consumption in 2008, as compared with coal's 26.8%. Natural gas accounted for 28.5% of the fossil fuel energy use in 2008, but only 21.4% of total energy-related CO<sub>2</sub> emissions. Energy-related CO<sub>2</sub> emissions account for 98% of the total U.S. CO<sub>2</sub> emissions (U.S. Department of Energy 2009a).

The United States emits about 1,900 million metric tons annually from coal-fired power plants, 33% of total energy-related CO<sub>2</sub> emissions, and 81% of CO<sub>2</sub> emissions from the U.S. electric power sector (U.S. Department of Energy 2009a). If public sentiment results in changed electric demand, or if GHG emissions are regulated, the demand forecast for coal for electric generation could change. The potential impacts of policy changes that could be made to limit or reduce GHG emissions will affect planning decisions for new power plants, particularly coal-fired facilities.

To assess the national electric generation portfolio (mix of electric generation technologies) and the mix of future electric generation technologies, the BLM reviewed the Annual Energy Outlook 2010 Report (U.S. Energy Information Administration 2009b). An independent study representing a forecast to the year 2035, it examined the ability of the domestic electric generation industry to alter the present electric generation portfolio. This report compares the 2035 projection to the electric generation mix that existed in 2008. This most recent report incorporates the 2009 downturn in electric demand, which resulted from lowered electric demand for manufacturing in the depressed domestic economy of 2009. This forecast estimated the coal-fired domestic electric generation at 44% by 2035, based on a slowing in electric demand through 2035, and a doubling, to 17%, of renewable electric generation by 2035. Based on this study, even with a considerably more optimistic projection for renewable sources, coal use continues to be projected as the largest portion of the domestic electric fuel mix.

Technologies are available for producing cleaner, more efficient, and more reliable power from coal. These include advanced pulverized coal, circulating fluidized bed, coal gasification or integrated gasification combined cycle, and carbon sequestration or carbon capture and storage technologies. Systems that use carbon capture technologies are designed to capture at least 90% of emitted CO<sub>2</sub>, which would be stored within geological formations (i.e., oil and gas reservoirs, saline formations, unmineable coal seams). These technologies are not used commercially because of the extremely high capital costs and low system reliability—the biggest obstacles to integration of these technologies into the power market. However, regulatory uncertainties are affecting planning decisions, for example, unless new coal-fired power plants are equipped with carbon capture and storage equipment they could incur higher costs as a result of higher expenses for siting and permitting. Nuclear and renewable power plants would not be directly affected by regulatory uncertainties because they do not emit GHGs.

The Electric Power Research Institute (EPRI) has also attempted to identify a scenario of how the full portfolio of technologies to provide for electric energy would respond if a national policy required CO<sub>2</sub> emissions to be reduced to 1990 levels (James 2007). EPRI updated this research in an October 2009 report, *The Power to Reduce CO<sub>2</sub> Emissions: The Full Portfolio* (EPRI 2009), which used the EIA's Annual Energy Outlook 2009 Report for comparison.

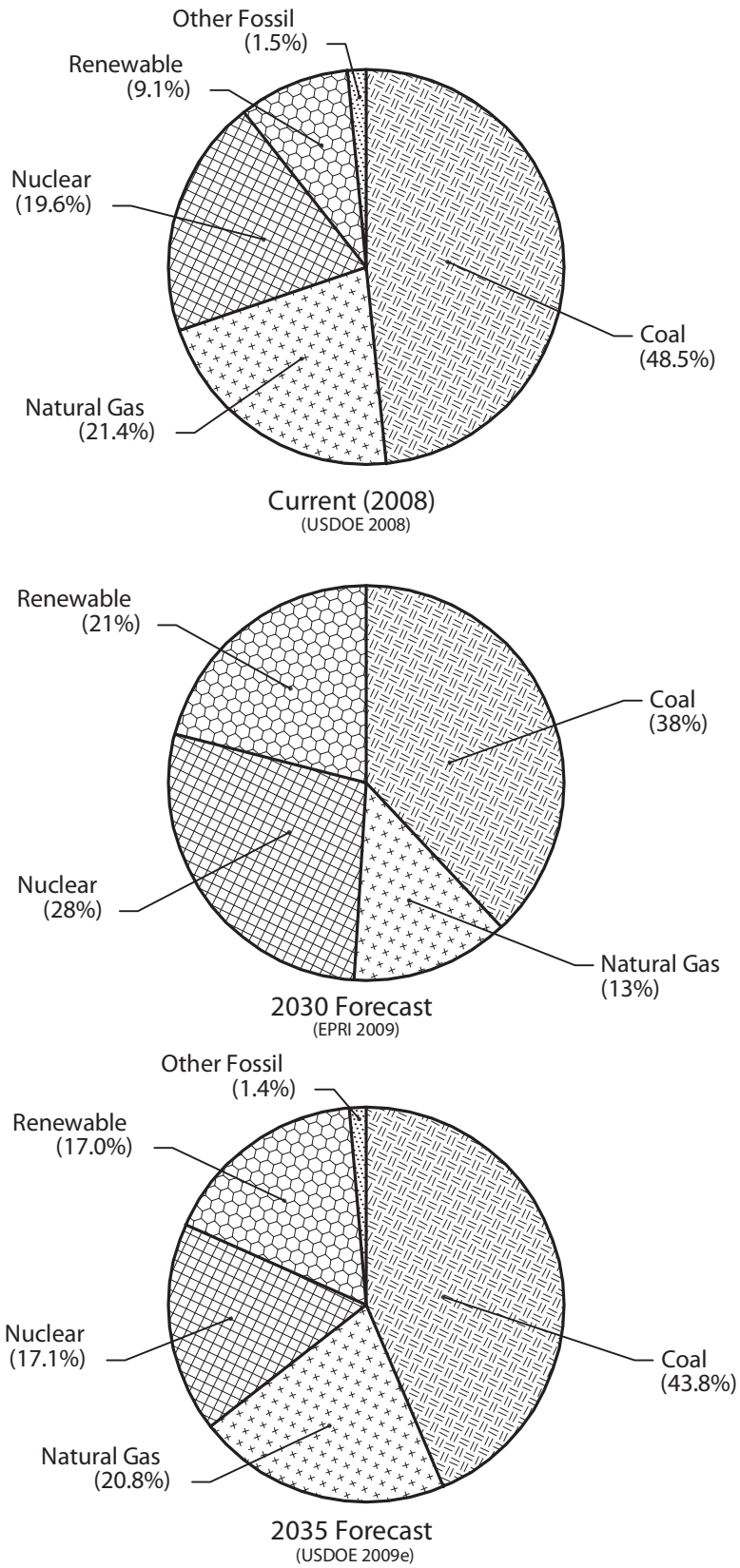
The EPRI study predicts that a national policy that forces a reduction of CO<sub>2</sub> emissions to 1990 levels would promote increased energy efficiency, and the growth of “non carbon” sources such as nuclear and renewable. Renewable sources include wind and solar, as well as emerging technologies like tidal power, river turbines, and others reported in the media. Hydropower is limited because most opportunities for hydropower have been used or require large infrastructure. Use of carbon based sources such as gas and petroleum are less than forecasted by the EIA, while coal use remains about the same in the EPRI forecast, mostly due to forecasted improvement in GHG emission reduction in coal fueled generation. Both the EIA and EPRI forecast an increase in electricity cost.

Figure 4-6 shows the 2008 electric generation mix, compared to the 2035 EIA forecast (U.S. Energy Information Administration 2009b) as well as the older 2030 EPRI forecast (EPRI 2009). Both forecasts agree that the amount of coal-fueled electric generation is expected to drop from nearly 50% of the present total to about 40% of the total in future years. Coal is forecast to remain as the major electric generation component until at least 2035. Renewable energy (other than hydroelectric) and nuclear are forecast to increase, while natural gas and other fossil fuels (i.e., oil) are forecast to remain stable or decrease to a degree.

In 2003, the DOE initiated the FutureGen project, a first of its kind, commercial-scale coal-fired, near-zero-emissions power plant incorporating integrated gasification combined cycle with carbon capture and storage. This is the first facility of its kind to combine and test several cutting-edge technologies. FutureGen is a public-private partnership between the DOE and the FutureGen Alliance, a non-profit organization representing some of the world’s largest coal producers and electric utilities. The FutureGen Alliance and the DOE reached an agreement in June 2009 to proceed with the project, which will be located at Mattoon, Illinois. The project proposes to produce electricity by turning coal into gas, remove impurities, extract CO<sub>2</sub> from the waste stream, and then sequester the CO<sub>2</sub> underground. The Alliance is responsible for design, construction, and operation of the facility, and the DOE is responsible for independent oversight and coordinating participation of international governments. The DOE’s financial contribution will come from the American Recovery and Reinvestment Act. The DOE issued a NEPA ROD on July 14, 2009, to move forward (U.S. Department of Energy 2009b). The ROD allows the Alliance to proceed with site-specific activities, and over the following 8 to 10 months the project design, costs and funding plan will be refined. When operational the FutureGen facility will produce 275 MW of power and capture 90% of the carbon emissions; however, it may be operated at a 60% capture rate in the first three years to validate plant integration and sequestration capability, as well as manage the startup risks and costs. This technology should sequester a million tons of CO<sub>2</sub> annually (U.S. Department of Energy 2009b).

Other methods of generating electricity that result in fewer GHG emissions than burning coal include natural gas, nuclear, hydroelectric, solar, wind, and geothermal resources.

Natural gas plays a key role in meeting U.S. energy demands. Natural gas, coal and oil supply about 85% of the nation’s energy, with natural gas currently supplying about 22% of the total. The percentage contribution of natural gas to the U.S. energy supply is expected to remain constant for the next 20 years. According to EIA’s 2010 Annual Energy Outlook (U.S. Energy Information Administration 2009b), concerns about GHG emissions have little effect on construction of new capacity fueled by natural gas.



No warranty is made by the Bureau of Land Management for the use of the data for purposes not intended by BLM.

**Figure 4-6**  
Current and Forecast Mix of Electric Generation Sources

Unconventional natural gas resources are expected to play a larger role in the demand for natural gas for electricity generation (U.S. Department of Energy 2009b). Natural gas production from hydrocarbon rich shale formations, known as “shale gas” is one of the most rapidly expanding trends in onshore domestic oil and gas exploration and production today. Analysts estimate that by 2011, most new natural gas reserves will come from unconventional shale gas reservoirs (NETL 2009). From 2007 to 2030, domestic production of natural gas is expected to increase by 22% (U.S. Department of Energy 2009b).

EPRI (2009) projects the nuclear share of power generation to increase to about 28% by 2030 as the addition of new power plants and upgrades at existing units increases overall capacity and generation. The nuclear power share of total electricity generation remains somewhat constant between 17 and 19% by 2035 according to EIA (2009b).

The nation’s total electricity generation from renewable resources, hydroelectricity, geothermal, solar, wind, ethanol, bio-fuels, and bio-mass, supported by federal tax incentives and state renewable programs, was expected to increase from 9% in 2008 to 17% in 2035 (U.S. Department of Energy 2009d). EPRI (2009) is more optimistic with renewable sources reaching 21% by 2030.

The estimated cumulative CO<sub>2</sub> emissions that would be produced annually from the conventional combustion of the coal produced from the proposed tract or an alternative tract configuration under Alternative 2 (see 4.2.14.2) is based on the Buckskin Mine’s projected future mining rates. That estimate presents a scenario that assumes the demand for coal in the future would not differ from current demand. The scenario also assumes, technologies for producing cleaner, more efficient and more reliable power from coal (i.e., advanced pulverized coal, circulating fluidized bed, integrated gasification combined cycle, and carbon capture and storage) would not yet be commercially established, and an explicit federal policy would not yet have been enacted to limit or reduce U.S. GHG emissions. However, if generation shifted strongly toward natural gas, nuclear, and renewable power, as well as fossil technologies using carbon capture and storage equipment, those estimates of CO<sub>2</sub> emissions from the combustion of coal produced from the PRB would be lower than estimated in the prior discussion (Section 4.2.14.2).

#### *4.2.14.5 Mercury, Coal Combustion Residues, and Other By-Products*

One of the concerns associated with burning coal to produce electricity is the release of elements from coal to the environment (U.S. Geological Survey 2002b). When coal is burned, GHGs as well as mercury and other compounds and elements, including lead and cadmium, that may have direct or indirect effects on human health, are released (EPA 2009e). The principal pollutants generated by coal combustion that can cause health problems are particulates, sulfur and nitrogen oxides, trace elements (including arsenic, fluorine, selenium, and radioactive uranium and thorium), and organic compounds generated by incomplete burning (U.S. Geological Survey 2000).

In coal combustion, concentrations of these elements and compounds vary depending on the chemistry of the coal deposits and on the type of air pollution controls in place when the coal is burned. Coal use in developing countries can potentially cause serious human health impacts (U.S. Geological Survey 2000). Some coal mined in China contained high levels of arsenic, fluorine, selenium, and polycyclic aromatic hydrocarbons. This coal has caused severe, life-

threatening health impacts on some residents that burned the coal in unvented stoves in their homes (U.S. Geological Survey 2000).

Coal that is burned in the United States generally contains low to modest concentrations of potentially toxic trace elements and sulfur (U.S. Geological Survey 2000). Specifically, PRB coal is recognized as being a clean burning coal because of its low sulfur and low ash properties. An analysis conducted by the USGS (2002b) found that PRB coal contained, on average, approximately eight times less sulfur than coals being used from the Appalachian and Illinois basins to supply U.S. power plants (feed coal). PRB feed coal was also found to contain nearly half as much uranium (8.9 parts per million), seven times less arsenic (17 parts per million), five times less lead (19 parts per million), and three times less cadmium (1.1 parts per million) when compared to Appalachian and Illinois basin feed coals. When burned, PRB coal produced, on average, 38% less fly ash than Appalachian and Illinois basin coals (U.S. Geological Survey 2002b). The fly ash resulting from combusted PRB coal contained approximately 39 times less mercury than fly ash that was generated from combusted Appalachian and Illinois basin coal (U.S. Geological Survey 2002b).

Additionally, many U.S. coal-burning power plants use sophisticated pollution-control systems that efficiently reduce the emission of hazardous elements (U.S. Geological Survey 2000). The EPA conducted a detailed study of possible health impacts from exposure to emissions of approximately 20 potentially toxic substances from U.S. coal-burning power plants (U.S. Geological Survey 2000). The EPA concluded that, with the exception of possibly mercury, there is no compelling evidence to indicate that emissions from U.S. coal-burning power plants cause human health problems (U.S. Geological Survey 2000).

Mercury is a naturally occurring element and enters the atmosphere from natural sources, such as active volcanoes, and through human activities such as industrial combustion and mining (EPA 2006b). Natural sources of mercury, such as volcanic eruptions and emissions from the ocean, have been estimated to contribute about 33% of the current worldwide mercury air emissions; anthropogenic (human-caused) mercury emissions account for the remaining 67%, though these estimates are highly uncertain (EPA 2009f).

When fossil fuels burn, mercury vapor is released into the atmosphere where it may drift for a year or more, spreading with air currents over vast regions of the globe (U.S. Department of Energy 2006). In 1995, an estimated 5,500 tons of mercury was emitted globally from both natural and human sources (U.S. Department of Energy 2006). Coal-fired power plants in the United States contributed to less than 1% of that total (U.S. Department of Energy 2006).

Mercury is a global problem. It can travel thousands of miles in the atmosphere before it is deposited back to the earth in rainfall or in dry gaseous forms. The EPA estimates that about one-third of the U.S. anthropogenic mercury emissions are deposited within the contiguous United States and the remainder enters the global cycle (EPA 2009f).

Table 4-40 summarizes how the various continents contributed to worldwide human-caused mercury emissions in 2004. The 2004 emissions were estimated to account for about 3% of the global total (EPA 2009f). The EPA (2009e) estimates that 83% of the mercury deposited in the United States originates from international sources, with the remaining 17% coming from the United States and Canada. These figures include mercury from natural and anthropogenic sources.

**Table 4-40. 2004 Percent Contribution to Worldwide Anthropogenic Mercury Emissions**

Continent	Percent
Asia	53
Africa	18
Europe	11
North America	9
Australia	6
South America	4

Source: EPA 2009f.

In 2006, the EPA estimated that 50% to 70% of global atmospheric emissions came from fuel combustion, and much of it came from China, India, and other Asian countries. Coal consumption in Asia is expected to grow significantly over the next 20 years. This international source of mercury emissions may grow substantially if left unaddressed. (EPA 2006b.)

Over the past decade, addressing environmental and human health mercury risks has been a focus for the EPA. Overall U.S. mercury air emissions have been reduced by 45% since 1990. The EPA is most concerned with methyl mercury, a potent form of mercury to which humans are primarily exposed. (EPA 2006b.)

Atmospheric mercury can settle into water or onto land where it can be washed into the water. Certain microorganisms can transform mercury into methyl mercury, a highly toxic mercury compound that builds up in fish and shellfish when they feed. Methyl mercury is the only form of mercury that biomagnifies in the food web. Concentrations of methyl mercury in fish are generally about a million times the methyl mercury concentration in the water (EPA 2006b). The primary way humans are exposed is by eating fish containing methyl mercury (EPA 2006b).

Other animals that consume fish and shellfish can also be adversely affected. Birds and mammals that eat fish may be more exposed to mercury than other animals in water ecosystems (EPA 2008d). Exposure to high levels of methyl mercury may include death, reduced reproduction, slower growth and development, and abnormal behavior (EPA 2008d). Research has shown that most people's fish consumption does not cause a health concern, but high levels of methyl mercury in the bloodstream of unborn babies and young children may harm the developing nervous systems of those children (EPA 2006b).

The DOE's Office of Fossil Energy has been sponsoring studies on mercury emissions from coal-based power generators to identify effective and economical control options for the past decade (U.S. Department of Energy 2006). The Office of Fossil Energy manages the largest funded program for developing an understanding of mercury emissions and developing emission control technologies for the coal-fired electric generating industry in the United States (U.S. Department of Energy 2006). Research on advanced and improved mercury control technology is ongoing (U.S. Department of Energy 2006).

In the United States, coal-burning power plants are the largest human-caused source of mercury emissions being released into the air, accounting for about 40% of all domestic human-caused

mercury emissions (EPA 2008d). However, these emissions contribute little to the global mercury pool. The EPA estimated that mercury emissions from U.S. coal-fired power plants account for about 1% of the global total (EPA 2009f).

Coal production from the Wyoming PRB represented approximately 42% of the coal used for power generation in 2006, or about 0.4% of the global anthropogenic mercury emissions. The Buckskin Mine produced about 5.2% of the coal produced in the Wyoming PRB in 2006, which would represent about 0.005% of the global mercury emissions. Under the No Action Alternatives, mercury emissions attributable to burning coal produced by the Buckskin Mine would be extended at current levels up to approximately 14 years, while the mine recovers the remaining estimated 344.3 million tons of currently leased coal reserves. Under the Proposed Action or Alternative 2, the Buckskin Mine's contribution to global mercury emissions would be extended from two to six additional years, respectively. Uncertainties about future regulatory requirements and the use of the coal mined under either of the action alternatives make it difficult to project the impacts of mercury emissions produced by burning the coal.

Additionally, burning coal in electric utility boilers generates residual materials called coal combustion residues. These residues include non-combustible materials left in the furnaces and ash that is carried up the smokestacks and collected by air pollution control technologies. As previously referenced, coal and coal combustion residues can contain a variety of compounds, metals, and other elements depending on the coal deposit and the site-specific characteristics of where the coal originated. Coal-fired boilers are required to have control devices to reduce the amount of emissions that are released into the atmosphere (EPA 2007e). The use of air pollution control equipment at power plants has resulted in fewer emissions but has also increased the amount of solid residues.

In the past, coal combustion residues have been recycled or disposed of in landfills or surface impoundments. More recently, these residues have been disposed of in mines as part of the reclamation process. There can potentially be risks of contamination of drinking water supplies and surface water bodies by coal combustion residues, particularly when they are disposed of in mines (National Academy of Science 2006; EPA 2002c). Buckskin Mine does not dispose of combustion residues. The EPA is evaluating management options for solid wastes from coal combustion, including whether current management practices pose risks to human health or ecological receptors.

As stated, the Buckskin Mine produced about 5.2% of the coal produced in the Wyoming PRB in 2006. Under the No Action Alternative, production of coal combustion residue attributed to burning coal from the Buckskin Mine would be extended at about current levels for approximately 14 years, while the mine recovers the remaining estimated 344.3 million tons of currently leased coal reserves. Coal combustion residue related to burning coal mined under the Proposed Action or Alternative 2 would be extended from two to six additional years, respectively. Uncertainties about future regulatory requirements and the use of the coal mined under either action alternative make it difficult to project the impacts of disposing of the related coal combustion residues.

Depending on the size, shape, and chemical composition, some coal combustion residues can be recycled and beneficially reused as components of building materials or as replacement to raw materials that would ordinarily need to be mined (e.g., sand, gravel, or gypsum) (EPA 2007e).

Coal combustion products (CCPs) are produced primarily from the combustion of coal in coal-fired power plants (EPA 2007e) and can include the following materials: fly ash, bottom ash, boiler slag, and flue gas desulfurization material (EPA 2007e). Studies and research conducted or supported by the EPA, EPRI, other government agencies, and universities have indicated that the beneficial uses of CCPs have not been shown to present significant risks to human health or the environment (EPA 2009g).

Fly ash is a by-product of burning finely ground coal in a boiler to produce electricity. Physically, fly ash is a fine, powdery material composed mostly of silica and nearly all particles are round. Fly ash is a siliceous material that, in the presence of water, reacts with calcium hydroxide at ordinary temperatures to produce cement-like compounds. Because of its shape and properties, fly ash can be useful in cement and concrete applications. (EPA 2007h.)

Bottom ash is agglomerated ash particles, formed in furnaces burning pulverized coal that are too large to be carried in the flue gases. Bottom ash is coarse with grain sizes from fine sand to fine gravel. It can be used as a replacement for aggregate and is usually sufficiently well-graded in size to avoid the need for blending with other fine aggregates. (EPA 2007g.)

Boiler slag is the molten bottom ash collected at the base of slag tap and cyclone type furnaces. Boiler slag particles are uniform in size, hard, and durable with a resistance to surface wear. The permanent black color of this material is desirable for asphalt applications and aids in melting snow. (EPA 2007h.)

Flue gas desulfurization material is a product of a process typically used for reducing SO<sub>2</sub> emissions from the exhaust gas system of a coal-fired boiler. These materials can be used as embankment and road base material, wallboard manufacturing, and in place of gypsum to produce cement. Currently, the largest single market for flue gas desulfurization material is in wallboard manufacturing. (EPA 2007i.)

Using CCPs can generate significant environmental and economic benefits (EPA 2009f). CCPs can be used for raw feed for cement clinker, concrete, grout, flowable fill, structural fill, road base/sub-base, soil modification, mineral filler, snow and ice traction control, blasting grit and abrasives, roofing granules, mining applications, wallboard, waste stabilization/solidification, and soil amendment (EPA 2009f).

Using CCPs can reduce energy consumption and GHG emissions and can help reduce the need for landfill space. Economic benefits include reduced costs associated with managing coal ash and slag disposal, potential revenue from the sale of CCPs, and savings from using CCPs in place of other more costly raw materials (EPA 2009f).

CCPs offer product-performance benefits as well. Boiler slag is a sought-after replacement for sand in blasting grit because it is free of silica and eliminates the potential health risk of silicosis (EPA 2009g). High coal ash content concrete is used for building pavements designed to last 50 years—twice the lifetime of conventional pavements. Coal fly ash can create superior products because of its self-cementing properties (EPA 2007f). Using coal fly ash in concrete can also produce stronger and longer-lasting buildings (EPA 2007f). This not only reduces the costs of maintaining buildings, but also provides the additional environmental benefit of reducing the need for new concrete to repair or replace aging buildings. This translates to a significant reduction in future energy consumption and GHG emissions (EPA 2007f).

In 2005, demand had become so strong for coal ash that some power plants were selling all the ash they produced (EPA 2005d). The EPA estimated that by using 15 million tons of coal fly ash, the United States reduced its GHG emissions equivalent to the annual emissions of nearly 2.5 million passenger vehicles (EPA 2008e).

Because of the many potential uses of CCPs, the EPA has sponsored the Coal Combustion Products Partnership (C2P2) Program to further the beneficial use of these coal combustion by-products (EPA 2003b). With more than 170 private and public partners (EPA 2009c), the C2P2 Program is a cooperative effort between the EPA and various organizations to promote the beneficial use of CCPs and the environmental benefits which can result from the proper use of these potentially recyclable materials (EPA 2003b). The C2P2 program will help meet the national waste reduction goals of the Resource Conservation Challenge—an EPA effort to find flexible yet more protective ways to conserve valuable natural resources through waste reduction, energy recovery, and recycling (EPA 2009c).

In 2007, the United States used approximately 43% of its CCPs (EPA 2009c). The C2P2 program aims to reduce adverse effects on air and land by increasing the use of CCPs to 50% in 2011 from 32% in 2001 (EPA 2009d). The program also plans to increase the use of CCPs as a supplementary cement-like material in concrete by 50%, from 12.4 million tons in 2001 to 18.6 million tons in 2011 (EPA 2009d). This would decrease GHG emissions by avoiding cement manufacturing of approximately 5 million tons of cement (EPA 2009d).

Table 4-41 summarizes the magnitude and duration of cumulative impacts in the PRB based on the upper and lower estimates for coal production in the region. The Proposed Action and Alternative 2 are within the upper and lower coal production estimates used to project reasonably foreseeable impacts for the PRB Coal Review and to provide a basis for quantification of related impact-causing parameters. As described in section 4.0, the PRB Coal Review is not an analysis of the impacts associated with the development of a specific project in the PRB, such as the Hay Creek II coal lease application discussed in this EIS.

Table 4-41. Summary Comparison of Magnitude and Duration of Cumulative Impacts<sup>a,b</sup>

Description of Potential Impact by Resource	Magnitude, Type, and Duration of Impact	
Resource Name	Alternative 1 (No Action)	Proposed Action, Alternative 2
<b>Topography and Physiography</b>		
Alteration of topography following reclamation of coal disturbance areas	Permanent topographic moderation following reclamation	Same as Alternative 1
Alteration of topography to accommodate coal-related, oil and gas, and oil- and gas-related facilities	Long-term to permanent limited changes in discrete, scattered areas	Same as Alternative 1
<b>Geology and Mineral Resources</b>		
Recovery of coal resulting in reduction in coal resources and disturbance and replacement of overburden and topsoil	Moderate, permanent	Same as Alternative 1
Surficial disturbance and reclamation on oil and gas well sites and associated facilities	Moderate, long-term	Same as Alternative 1
<b>Paleontology</b>		
Coal, coal-related, oil and gas, and oil- and gas-related development disturbance of PFYC Class 5 Wasatch and Class 3 Fort Union formations	Permanent potential adverse effects to scientifically significant fossils that are present but not visible prior to disturbance	Same as Alternative 1
<b>Air Quality</b>		
Impacts to Wyoming near-Field Receptors 24-hour PM <sub>10</sub> and PM <sub>2.5</sub>	Maximum modeled impacts occurring at isolated receptors show localized exceedances of the WAAQS and NAAQS for the base year (2004) as well as for both coal production scenarios for 2015 and 2020	Same as Alternative 1
Annual PM <sub>10</sub>	Maximum modeled impacts at peak receptors show 20% increase from base year (2004); exceed the WAAQS for both coal production scenarios for 2015 but in compliance with WAAQS for both coal production scenarios for 2020	Same as Alternative 1
Annual PM <sub>2.5</sub>	Maximum modeled impacts at peak receptors show 20% increase from base year (2004) and localized exceedances of the WAAQS and NAAQS for both coal production scenarios for 2015 and 2020	Same as Alternative 1

#### 4.0 Cumulative Environmental Consequences

Table 4-41. Continued

Description of Potential Impact by Resource		Magnitude, Type, and Duration of Impact	
Resource Name	Alternative 1 (No Action)	Proposed Action, Alternative 2	
All other parameters	Modeled impacts in compliance with WAAQS and NAAQS for both coal production scenarios for 2015 and 2020	Same as Alternative 1	
Impacts to Montana near-Field Receptors All parameters	Impacts at all Montana receptors would be in compliance with NAAQS and Montana AAQS (MAAQS) for most pollutants and averaging periods. 1-hour NO <sub>2</sub> concentrations for all years and development scenarios were predicted to exceed NAAQS. 1-hour NO <sub>2</sub> concentrations were predicted to exceed MAAQS in 2015 at isolated locations because of CBNG development in Wyoming but drop below MAAQS by 2020. Impacts are predicted to decrease for annual NO <sub>2</sub> , PM <sub>10</sub> and PM <sub>2.5</sub> relative to the base year (2004) because of anticipated southward progression of nearby CBNG wells	Same as Alternative 1	
Non-regulatory PSD Impacts at Class I and Sensitive Class II Areas Class I Northern Cheyenne Indian Reservation	Modeled impacts above Class I increment levels for 24-hour PM <sub>10</sub> for all years and coal production scenarios; for 24-hour SO <sub>2</sub> for both coal production scenarios for 2020; for 3-hour SO <sub>2</sub> for upper coal production scenario for 2020	Same as Alternative 1	
Class I Badlands National Park	Modeled impacts above Class I increment levels for 24-hour PM <sub>10</sub> for both coal production scenarios for 2020	Same as Alternative 1	
Class I Wind Cave National Park	Modeled impacts above Class I increment levels for 24-hour PM <sub>10</sub> for all years and coal production scenarios	Same as Alternative 1	
All Sensitive Class II Areas (including Cloud Peak Wilderness Area and Crow Indian Reservation)	Modeled impacts below Class II increments for all Sensitive Class II areas for base year (2004) and both coal production scenarios for 2020	Same as Alternative 1	
Visibility Impacts Class I Areas	Modeled impacts show 200 or more days a year during the base year (2004) with a change of 1.0 dv or greater at the Northern Cheyenne Indian Reservation, Badlands National Park, and Wild Cave National Park.; the same three Class I areas have the highest predicted visibility change in 2020	Same as Alternative 1	
Sensitive Class II Areas	All but four areas have more than 100 days a year during the base year (2004) with a change of 1.0 dv or greater	Same as Alternative 1	
Acid Deposition Impacts	All modeled impacts below the deposition threshold values for nitrogen and sulfur compounds	Same as Alternative 1	

#### 4.0 Cumulative Environmental Consequences

**Table 4-41. Continued**

Description of Potential Impact by Resource	Magnitude, Type, and Duration of Impact	
Resource Name	Alternative 1 (No Action)	Proposed Action, Alternative 2
Florence Lake	Modeled impact above 10% ANC threshold for both coal production scenarios for 2015 and 2020	Same as Alternative 1
Upper Frozen Lake	Modeled impact above 1 µeq/L ANC for both coal production scenarios for 2015 and 2020	Same as Alternative 1
All other modeled sensitive lakes	Modeled impact below 10% ANC threshold values for both coal production scenarios for 2015 and 2020	Same as Alternative 1
<b>Groundwater Resources</b>		
Removal of coal aquifer and replacement with backfill material	Moderate, long-term to permanent for mining areas	Same as Alternative 1
Lowering of water levels in aquifers around the mines	Moderate, long-term in area immediately west of mines	Same as Alternative 1
Water level decline in sub-coal aquifers as a result of all development	No cumulative impacts anticipated	Same as Alternative 1
Change in groundwater quality as a result of all development	No cumulative impacts anticipated	Same as Alternative 1
Overlapping drawdown in the coal aquifer caused by surface mining and CBNG development	Additive, long-term in area immediately west of surface coal mines	Same as Alternative 1
<b>Surface Water Resources</b>		
Surface disturbance of intermittent and ephemeral streams and scattered ponds and reservoirs as a result of coal mining, coal-related, oil and gas, and oil- and gas-related development	Moderate, short-term	Same as Alternative 1
Discharge of coal mining and CBNG produced waters into intermittent and ephemeral streams	Moderate, short-term	Same as Alternative 1
Sediment input into intermittent and ephemeral streams and scattered ponds and reservoirs as a result of coal mining, coal-related, oil and gas, and oil- and gas-related development	Moderate, short term	Same as Alternative 1
<b>Alluvial Valley Floors</b>		
Coal mining disturbance of AVFs determined to be significant to agriculture	Not permitted by regulation	Same as Alternative 1
Coal mining disturbance of AVFs determined not to be significant to agriculture	AVFs disturbed by mining must be restored to essential hydrologic function; no cumulative impacts anticipated	Same as Alternative 1

#### 4.0 Cumulative Environmental Consequences

Table 4-41. Continued

Description of Potential Impact by Resource	Magnitude, Type, and Duration of Impact	
Resource Name	Alternative 1 (No Action)	Proposed Action, Alternative 2
<b>Soils</b>		
Coal mining, coal-related, oil and gas, and oil- and gas-related disturbance and replacement of soil resources	Moderate, short-term and long-term impacts through accelerated wind or water erosion, declining soil quality factors through compaction, reduced microbial populations and organic matter, and potential mixing of soil zones	Same as Alternative 1
CBNG water disposal impacts to soil resources	Potential increase in soil alkalinity depending on SAR levels in water and method of water disposal	Same as Alternative 1
<b>Wetland and Riparian Vegetation</b>		
Removal of jurisdictional wetlands and loss of wetland function until reclamation occurs	Moderate, short-term; no net loss	Same as Alternative 1
CBNG-related discharge of produced water	Moderate, short- to long-term creation of wetlands in areas that previously supported upland vegetation	Same as Alternative 1
<b>Vegetation</b>		
Coal mining, coal-related, oil and gas, and oil- and gas-related removal and replacement of native vegetation	Moderate, short- to long-term impacts because of potential differences in species composition and presence and size of woody species on reclaimed lands	Same as Alternative 1
Coal mining, coal-related, oil and gas, and oil- and gas-related impacts to Special Status Plant Species	Potential incremental loss or alteration of potential or known habitat	Same as Alternative 1
Coal mining, coal related, oil and gas, and oil- and gas-related dispersal of noxious and invasive species	Potential displacement of native species and changes in species composition	Same as Alternative 1
<b>Wildlife and Fisheries</b>		
Direct and indirect coal mining, coal-related, oil and gas, and oil- and gas-related development impacts to game and non-game species, including direct mortality, habitat fragmentation, animal displacement, noise and increased human presence	Moderate, short-term	Same as Alternative 1
Coal mining, coal-related, oil and gas, and oil- and gas-related disturbance of game and nongame species habitat during project development and operation	Moderate, short-term loss of all types of habitat present in disturbed areas	Same as Alternative 1

#### 4.0 Cumulative Environmental Consequences

**Table 4-41. Continued**

Description of Potential Impact by Resource	Magnitude, Type, and Duration of Impact	
Resource Name	Alternative 1 (No Action)	Proposed Action, Alternative 2
Coal mining, coal related, oil and gas, and oil- and gas-related habitat changes after reclamation	Moderate, long-term change in habitat with potential changes in associated wildlife populations	Same as Alternative 1
Alteration or loss of habitat because of coal mining, coal-related, oil and gas, and oil- and gas-related development	Negligible to moderate, short- to long-term	Same as Alternative 1
Changes in water quality as a result of surface disturbance or introduction of contaminants into drainages caused by coal mining, coal-related, oil and gas, and oil- and gas-related development	Minor to moderate, short- to long-term	Same as Alternative 1
Changes in available habitat as a result of water withdrawals or discharges related to coal mining, coal-related, oil and gas, and oil- and gas-related development	Moderate, short-term	Same as Alternative 1
<b>Special Status Species</b>		
Direct and indirect coal mining, coal-related, oil and gas, and oil- and gas-related development impacts, including direct mortality, breeding area, nest or burrow abandonment, sage-grouse lek abandonment, noise and increased human presence	No effect on threatened or endangered species; moderate, short- to long-term effects on candidate vertebrate species	Same as Alternative 1
Coal mining, coal-related, oil and gas, and oil- and gas-related disturbance of habitat (breeding and nesting) during project development and operation	No effect to moderate, short- to long-term loss of all types of special status species habitat present in disturbed areas	Same as Alternative 1
Coal mining, coal related, oil and gas, and oil- and gas-related habitat changes after reclamation	No effect to moderate, short- to long-term change in habitat with potential changes in associated populations of special status species	Same as Alternative 1
<b>Land Use and Recreation</b>		
Loss of forage and range improvements and restriction of livestock movement because of coal mining, coal-related, oil and gas, and oil- and gas-related development	Moderate, short-term	Same as Alternative 1
Disturbance of developed recreation sites by coal mining, coal-related, oil and gas, and oil- and gas-related development	Negligible, short-term	No additional impacts, private surface

4.0 Cumulative Environmental Consequences

Table 4-41. Continued

Description of Potential Impact by Resource	Magnitude, Type, and Duration of Impact	
Resource Name	Alternative 1 (No Action)	Proposed Action, Alternative 2
Reduction or degradation of opportunities for dispersed recreation activities related to coal mining, coal-related, oil and gas, and oil- and gas-related development	Moderate, short-term on existing mine areas	No additional impacts, private surface
<b>Cultural Resources and Native American Concerns</b>		
Disturbance of cultural resource sites	Ineligible sites could be destroyed without protection or further work; no impact on known sites; impacts on eligible sites discovered during operations would be avoided or mitigated through data recovery prior to mining; no impact on known unevaluated sites; impacts on unevaluated sites are not permitted; unevaluated sites would be evaluated prior to mining	Same as Alternative 1
<b>Transportation and Utilities</b>		
Movement of segments of existing public roads, pipelines, transmission lines, or railroads to accommodate coal mining development	Moderate, long-term to permanent, disruptive effects would be minimized	Same as Alternative 1
Increased vehicular traffic on roads and highways because of coal mining, coal-related, oil and gas, and oil- and gas-related development, and associated impacts including traffic accidents, road wear, air emissions, dust, noise, and vehicle collisions with wildlife and livestock	Moderate, short-term	Same as Alternative 1
Construction and operation of additional railroad and pipeline facilities and transmission lines to transport coal, oil and gas, and electricity	Moderate, short- to long-term	Same as Alternative 1
<b>Socioeconomics</b>		
Increases in employment related to coal mining, coal-related, oil and gas, and oil- and gas-related development	Significant, short- to long-term	Negligible added with Hay Creek II LBA
Increases in personal income because of employment increases related to coal mining, coal-related, oil and gas, and oil- and gas-related development	Significant, beneficial, short- to long-term	Negligible added with Hay Creek II LBA
Increase in population because of employment increases related to coal mining, coal-related, oil and gas, and oil- and gas-related development	Significant, short- to long-term	Negligible added with Hay Creek II LBA

Table 4-41. Continued

Description of Potential Impact by Resource	Magnitude, Type, and Duration of Impact	
Resource Name	Alternative 1 (No Action)	Proposed Action, Alternative 2
Expansion of housing supply because of employment increases related to coal mining, coal-related, oil and gas, and oil- and gas-related development	Significant, short- to long-term	Negligible added with Hay Creek II LBA
Increases in school enrollment because of employment increases related to coal mining, coal-related, oil and gas, and oil- and gas-related development	Moderate, short-term	Negligible to minor added with Hay Creek II LBA
Need for additional local government facilities and services because of employment increases related to coal mining, coal-related, oil and gas, and oil- and gas-related development	Moderate, short- to long-term	No impacts added with Hay Creek II LBA
Increased federal, state, and local revenues related to coal mining, coal-related, oil and gas, and oil-and gas-related development	Significant, beneficial, short- to long-term	Same as Alternative 1

<sup>a</sup> Cumulative impacts discussion and table are based on the PRB Coal Review analyses (BLM 2005a–f, 2006c–e, 2008a, 2009c–g). The Proposed Action and alternatives fall within those impact projections.

<sup>b</sup> All impacts are assumed to be adverse unless noted otherwise.