

David H. Coburn
202 429 8063
dcoburn@steptoe.com

1330 Connecticut Avenue, NW
Washington, DC 20036-1795
202 429 3000 main
www.steptoe.com

EI - 20119

Steptoe
STEPTOE & JOHNSON LLP

February 6, 2013

Mr. Kenneth Blodgett
Surface Transportation Board
395 E Street, SW
Washington, DC 20423

Mr. Alan Summerville
ICF International
9300 Lee Highway
Fairfax, VA 22031

**Re: Docket No. FD 30186, Tongue River Railroad Company, Inc.—Rail
Construction and Operation—in Custer, Powder River and Rosebud
Counties, Mont.; Information Request #1**

Dear Messrs. Blodgett and Summerville:

In reference to the January 23, 2013 request received from Ms. Vicki Rutson for certain information required for the environmental review in this proceeding, please find attached a document which responds to the five questions posed in that request.

Please let us know if you have any questions about the attached responses.

Sincerely,



David H. Coburn
Attorney for Tongue River Railroad Company

cc: Director Victoria Rutson

- 1. The December 17, 2012 supplemental application (“Supplemental Application”) states that coal from the Otter Creek mine could move east or west for domestic use or export, including export to Asia. See Rowlands VS at 4. Please provide more specific information about the potential market locations for the coal that would be transported from the mines identified in the Supplemental Application via the Tongue River Railroad. If TRRC does not have this information, OEA requests a detailed explanation of why this information cannot be supplied.**

Response: TRRC does not have specific information about the markets to which the coal that it would transport would be destined. The coal that TRRC expects to transport will originate at the Otter Creek mine, which is owned by a subsidiary of Arch Coal, Inc., as well as from mines that TRRC anticipates could be developed at other points in the Ashland area where there are known reserves of coal. Coal from the Otter Creek mine will not be available for sale for at least several more years, perhaps 2017 at the earliest. This takes into account the time it will take, following permitting, to develop the mine, obtain the required land rights for the rail line, and construct the railroad (a process which will take about 20 months spread out over three years assuming eight month construction seasons). Given the variety of factors that can influence the timeline (e.g., weather-spawned development or construction delays, market volatility) and the fact that coal will not be available for sale for at least several years, predictions as to exactly where that coal will be sold and shipped cannot be made at this time.

The Otter Creek mine is accordingly being developed on the basis that there will be a market for the coal mined there, but without any specific domestic or foreign purchasers for the coal identified at this early stage. There are no contracts in place to purchase the coal and Arch is neither actively marketing the coal to be produced at Otter Creek nor able to do so given the long lead time until the mine and railroad are developed. As TRRC stated in its Application, destination markets will be determined by the market forces in play at the time when the coal is mined. Nonetheless, as stated in the Application and explained further below, there is ample reason to believe that there will be a market for the coal once it becomes available for transport.

The level of uncertainty as to identification of specific destinations for coal that TRRC would transport is even greater with respect to coal mined at other mines that could be developed in the Ashland area. At this time, there are no proposals to develop such mines or mine permits pending. While TRRC believes that it is likely that at some point other mines in the area will be developed to exploit the significant resource located there, identifying where the coal from those anticipated mines will be transported is speculative at this time because the timelines for such other mines to begin production are even longer than for the Otter Creek mine.

For the above reasons, TRRC cannot offer more detailed information on the location of specific markets for the coal it will transport. However, historical information is available on where Montana coal has found a market. The table attached at Exhibit 1, which is compiled from U.S. Energy Information Administration data, shows for each

year between 2007 and 2012, the largest percentage of Montana coal has been used for electricity generation within the state, with the next largest volumes being transported to electric utilities in Michigan, Minnesota, and Washington. Smaller volumes have been transported to primarily Midwest and Northern Plains states, and to Arizona. (The 2012 data shown on the Table is not complete at this time.)

The table at Exhibit 2, also compiled from EIA data, identifies the specific utilities to which Montana coal has been transported between 2007 and 2012. These utilities include Xcel Energy, DTE Energy (Detroit Edison), Allete Inc. (Minnesota Power); CMS Energy and Wisconsin Energy, among others. Arch anticipates that these same utilities in the Upper Midwest states will remain the largest potential domestic customers for the Otter Creek coal, as well as the Centralia units in Washington, one of which is scheduled to remain operational through 2025.

The July 12, 2006 study, entitled “Otter Creek Property Summary Report”, prepared by Norwest Corporation for the Montana Land Board in advance of that Board’s decision to lease the Otter Creek coal tracts to an affiliate of Arch is attached as Exhibit 3. Chapter 4 of the Report discusses the potential market for the Otter Creek coal. Table 4-1 identifies the specific plants in the Upper Midwest and Washington that currently purchase coal from Montana mines at Spring Creek, Decker and Rosebud. The Report is consistent with Arch’s view that these plants are potential customers for Otter Creek coal. The same plants are likewise potential customers for coal mined at other Ashland area mines that are developed.

Otter Creek coal is located relatively close to the surface and has a low ratio of coal to overburden, versus generally higher strip ratios at other Montana mines. See comparison of PRB mine strip ratios set forth at Exhibit 4. This means that the coal can be mined efficiently and at a lower cost than at the other Montana mines with which Otter Creek coal would compete, which will make that coal more competitive.

In addition to the above domestic market opportunities, there is also an export market for Montana coal. This is discussed in the Application and in TRRC’s January 28, 2013 Reply to the Petition to Revoke filed by NPRC. According to EIA’s most recent statistics, in 2011, over 13 million tons of Montana coal were exported. This compares to over 25 million tons distributed domestically. See EIA report at Exhibit 5. The exported coal includes a few million tons of coal exported to Canada for use in generating electricity.

Some of the TRRC-transported coal could be exported to Europe through the Midwest Energy Resources Company facility at Superior, WI, from which Montana coal is currently shipped via Great Lakes and ocean vessels to Europe. The largest markets in Europe are the UK and Spain.

Some other portion of the TRRC-transported coal could be exported to Asia via the Westshore Terminals south of Vancouver, BC, via which Montana coal is currently exported. The coal might also be exported through facilities proposed to be constructed

in the State of Washington were such facilities to be developed. However, as noted in TRRC's Reply to the Petition to Revoke, it is far from certain that these planned facilities, now in the permitting phase, will be constructed, and markets exist for Otter Creek coal regardless of whether the plans for those facilities ever come to fruition. The volume of TRRC-transported coal that could be exported to Asia will in part turn on the availability of additional export capacity and thus relatively lesser amounts of coal will be exported to Asia in the event that these facilities are not developed.

To the extent that TRRC-transported coal were exported to Asia, the most likely recipient nations include South Korea, Japan, and China. See Census Bureau data at Exhibit 6. South Korea is a more likely potential destination than other Asian nations due to relative geographic proximity to the North American west coast, which translates to lower ocean transport costs.

The contention that many parties have made in their scoping comments that all of the Otter Creek coal will be exported to China is not supported by any facts. Arch has no contracts and no fixed plans to ship any of the Otter Creek coal to China. Whether it is exported to China at all is very much an open question given the historically greater use of Montana coal for domestic electricity generation than for export and market forces that could dictate a greater demand for the coal for domestic use and/or for export to nations other than China. According to Census and EIA data, South Korea ranks well ahead of China in terms of its import from the United States of thermal or steam coal, the type of coal exported from the PRB. See Exhibits 6 and 7.

It is not possible to accurately predict what percentage of the TRRC-transported coal would be consumed domestically versus exported, and which nations would likely receive coal that is exported, this many years in advance of any production from the Otter Creek/Ashland area. Multiple factors will dictate whether coal will be exported at all and, if so, where it will be exported. These factors include the following: the cost of competitive fuel, and in particular natural gas; regulatory developments that could influence the ability of domestic and foreign utilities to use coal versus other fuels; and technological advances in the use of coal, which include the further development of carbon capture technologies, and the commercial development of coal to liquid and coal to gas conversion facilities. Montana coal's attractiveness to the domestic market will also be influenced by the availability of coal at competitive prices from other coal producing areas in the United States. In this regard, it bears note that EIA forecasts growing domestic use of coal as an energy resource beginning after 2016 and growth over current usage levels by several quadrillion Btu's by 2035. See page 11 of EIA, *Annual Energy Outlook Early Release 2013*, attached at Exhibit 8. Thus, predictions that there will be little or no domestic market for Otter Creek coal in the future do not comport with the opinions of unbiased market observers and analysts.

For that coal which may be exported, factors that would influence the specific destination of any coal would include the following: the cost of available competitive fuel (e.g., coal is currently attractive in Europe due to the high cost of natural gas there);

the cost of ocean and other transportation and the availability of export and import facilities.

Finally, the variability of the above factors over time, and the general dynamism of energy markets, suggests that over the life of the Otter Creek mine the percentage of the coal used domestically versus the percentage exported will vary.

- 2. The Supplemental Application states that Otter Creek coal may find markets overseas through U.S. ports along the Atlantic, Pacific, Great Lakes or Gulf Coasts. See Supplemental Application at 20. Please provide information about any potential plans to transport Otter Creek coal through U.S. ports in these locations.**

See response to question 1. Generally, to the extent that the coal is exported, transit distance within the United States suggests that it is more likely to be exported through Great Lakes and Pacific ports than Gulf Coast or Atlantic ports, should Great Lakes and Pacific ports have available capacity. At this point, however, there are no specific plans to export any of the coal for the reasons discussed in response to question 1.

- 3. Please provide any information about potential shippers with whom Arch Coal has negotiated or signed contracts to ship Powder River Basin (PRB) coal from the Northern PRB on the Tongue River Railroad.**

As noted above, to TRRC's knowledge, no contracts have been negotiated or signed to date.

- 4. Please provide justification for construction and operation of the Montco Mine spur to Terminus Point #1 (including information about the Montco mine itself and other mines in the vicinity that might potentially be served by the spur in the future).**

TRRC is aware that there are reserves of coal in the Ashland area, including coal on the Northern Cheyenne Reservation and at the area formerly designated for mining known as the Montco Mine. The Application thus seeks authority to construct a portion of the TRRC line (referred to in the Application as the Montco Mine Spur) to serve this coal resource.

While precise information on the amount of marketable coal in that area remains under review, the reserves are known to be substantial. Based on that knowledge and the reasonable assumption that coal developers may emerge to develop one or more mines in the area that would be served by Terminus Point #1, TRRC believes that there is an economic justification for the Montco Mine spur and that authorization of that portion of the TRRC line is in the public interest and would advance a sound transportation system.

In addition, authorizing the Montco Mine spur in this proceeding would be most efficient from TRRC's perspective and that of the STB and other permitting agencies.

Doing so would allow the environmental review and transportation merits assessments to be accomplished at the same time as the review of the portion of the line that would serve the Otter Creek mine, thereby saving significant time and resources that otherwise would be required were permitting of the Montco Mine spur to be delayed.

5. The Supplemental Application states that 3.7 trains per day would travel on the Tongue River Railroad. Because this number represents the average number of trains per day, please provide the maximum number of trains per day that could potentially travel on the Tongue River Railroad in the reasonably foreseeable future if the line is approved and constructed.

As discussed in TRRC's Reply to Petition to Revoke, the predicted 3.7 average number of loaded trains per day was based on the assumption that the Otter Creek mine will reach its anticipated maximum production level of 20 million tons of coal per year. This is a simple average based on the capacity of a unit coal train and this maximum production level. (20 million tons/year divided by 125 cars/train times 365 days/year) = 3.65 trains/day, which was rounded up to 3.7 trains/day in the Application.)

Many factors on the rail network can cause more or less trains to traverse the line on a given day. These factors include track maintenance, service interruptions caused by derailments, weather or other issues; the level of any delays in loading rail cars at the mine or delays at destination.

The maximum number of trains/day that could use the line were no siding built on the TRRC line is between 3 and 4 loaded trains and approximately 7 to 8 total (loaded and empty) trains/day. Were an 8500 foot siding built on the TRRC line (as the Application notes is possible were traffic levels to demand the need for a siding) the maximum number of trains/day that could be transported would be about 5 loaded trains/day or a total of about 10 loaded and empty trains/day.

Montana Coal Transactions by State

Data Source: ABB Velocity Suite (EIA Form 923 -Power Plant Operations: OMB 1905-0129)

ST	2007	2008	2009	2010	2011	2012	
MT	10,724	11,405	8,954	10,952	9,165	6,978	58,178
MI	10,141	9,705	9,397	9,648	9,044	6,964	54,900
MN	11,722	11,524	9,725	8,456	7,217	3,346	51,990
WA	5,184	4,120	2,586	2,504	2,436	1,358	18,189
IN	1,647	1,571	794	167	212		4,391
AZ	599	720	533	683	659	707	3,902
ND	752	802	724	747	752		3,777
WI	657	562	501	535	438	791	3,485
OH	56	130	387	1,241	370	221	2,404
PA	130	195	218	181			724
WV	277	232	68	1			578
NY		260	198				458
OR			28	152	108		289
IA			29	44			74
SD						55	55
CO			50				50
TX		28		0			28
OK					14		14

Montana Coal Transactions by Holding Company

Data Source: ABB Velocity Suite (EIA Form 923 -Power Plant Operations: OMB 1905-0129)

Holding Company	Plant	St	2007	2008	2009	2010	2011	2012	
PPL Corp	Colstrip	MT	9,896	10,654	8,082	10,078	8,405	6,978	54,093
Xcel Energy Inc	Sherburne County	MN	6,009	5,269	4,892	4,400	4,729	1,628	26,927
DTE Energy Co	Belle River	MI	4,004	3,691	4,286	4,527	4,079	2,975	23,562
DTE Energy Co	St Clair	MI	4,114	3,808	2,884	3,092	3,002	2,690	19,591
ALLETE Inc	Clay Boswell	MN	3,953	4,557	3,647	3,233	1,763	1,542	18,695
TransAlta Corp	Centralia Complex	WA	5,100	4,022	2,480	2,388	2,343	1,267	17,600
Btu Solutions LLC	State Line Energy	IN	1,647	1,571	794	27			4,039
CMS Energy Corp	B C Cobb	MI	605	964	854	619	576	374	3,992
Wisconsin Energy Corp	Presque Isle	MI	692	669	622	645	844	484	3,955
Great River Energy	Stanton (ND)	ND	731	794	724	747	752		3,748
Salt River Project	Coronado	AZ	513	594	505	683	617	693	3,605
Alliant Energy Corp	Nelson Dewey	WI	628	562	501	525	381	460	3,057
ALLETE Inc	Taconite Harbor	MN	794	844	547	315	217	176	2,894
CMS Energy Corp	J C Weadock	MI	501	389	511	509	307	441	2,658
Beowulf Energy LLC	Centennial Hardin (MT)	MT	525	429	565	564	462		2,545
Otter Tail Corp	Hoot Lake	MN	577	467	353	508	484		2,389
MDU Resources Group Inc	Lewis & Clark	MT	302	322	307	310	297		1,539
FirstEnergy Corp	Bay Shore	OH		13	93	1,045	312		1,464
ALLETE Inc	Syl Laskin	MN	389	387	285		24		1,086
Marquette Board of Light & Power	Shiras	MI	208	180	191	194	188		961
Weyerhaeuser Co	Longview (WA WEYER)	WA	85	98	106	116	94	91	589
FirstEnergy Corp	Willow Island	WV	277	188	30				495
Carlyle Group (The)	AES Somerset LLC	NY		248	184				432
FirstEnergy Corp	Eastlake (OH)	OH			41	79	58	207	385
NRG Energy Inc	Cheswick Power Plant	PA	122	105	136				363
Wisconsin Energy Corp	Valley (WI)	WI				10	14	332	356
American Electric Power Co Inc	Rockport	IN				139	212		352
NRG Energy Inc	Avon Lake	OH	56	98	194				347
Portland General Electric Co	Boardman (OR)	OR			28	152	108		289
Pinnacle West Capital Corp	Cholla	AZ	86	127			43	14	269
FirstEnergy Corp	Bruce Mansfield	PA				179			179
Wyandotte Dept of Municipal Serv	Wyandotte (MI)	MI		4	49	49	20		123
FirstEnergy Corp	Ashtabula	OH		13		103			116
FirstEnergy Corp	Hatfields Ferry	PA		34	72	2			108
NRG Energy Inc	New Castle Plant	PA	8	57	10				75
Cedar Falls Utilities	Streeter	IA			29	44			74
FirstEnergy Corp	Lake Shore	OH			40	14		14	67
FirstEnergy Corp	Fort Martin	WV		27	35	1			62
Otter Tail Corp	Big Stone	SD						55	55
Xcel Energy Inc	Valmont	CO			50				50
Dairyland Power Coop	Alma	WI					44		44
Holland Board of Public Works	James de Young	MI				13	28		41
MDU Resources Group Inc	Heskett	ND	21	8					29
Xcel Energy Inc	Bay Front	WI	29						29
Arizona Electric Power Coop Inc	Apache Station	AZ			28				28
American Electric Power Co Inc	Oklaunion	TX		28					28
Carlyle Group (The)	AES Cayuga	NY		9	14				23
Grand Haven Light & Power	J B Simms	MI	18						18
FirstEnergy Corp	Harrison (WV)	WV		13	3				16
AES Corp (The)	AES Shady Point Inc	OK					14		14
FirstEnergy Corp	W H Sammis	OH			14				14
NRG Energy Inc	Niles (OH ORION)	OH		6	5				11
FirstEnergy Corp	Pleasants	WV		4	0				4
AES Corp (The)	AES Greenidge	NY		3					3
Texas Municipal Power Agency	Gibbons Creek	TX				0			0

**OTTER CREEK
PROPERTY SUMMARY
REPORT**

Volume I of II

ENERGY, MINING, AND ENVIRONMENTAL CONSULTANTS

NORWEST
CORPORATION

**OTTER CREEK
PROPERTY SUMMARY
REPORT**

Volume I of II

Submitted to:
**GREAT NORTHERN
PROPERTIES, L.P.**

and:
**MONTANA DEPARTMENT
OF NATURAL RESOURCES
AND CONSERVATION**

July 12, 2006

NORWEST CORPORATION

136 East South Temple
12th Floor
Salt Lake City, Utah 84111
TEL (801) 539-0044
FAX (801) 539-0055
USA (800) 266-6351
slc@norwestcorp.com

1212 Bath Avenue
Sixth Floor, Suite 1
Ashland, KY 41101
TEL (606) 920-9833
FAX (606) 920-9664
ashland@norwestcorp.com

www.norwestcorp.com

NORWEST
CORPORATION

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EXECUTIVE SUMMARY

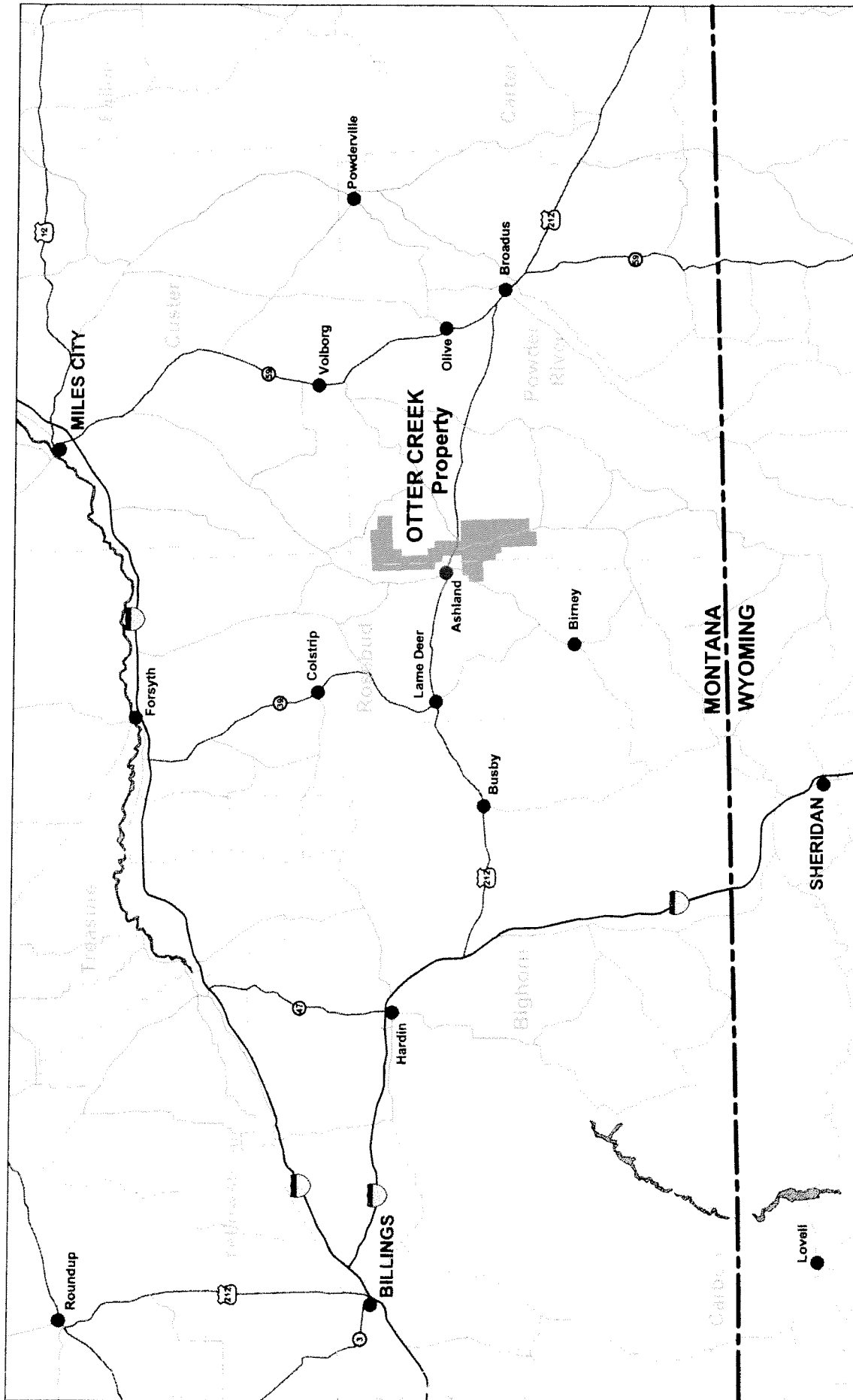
Norwest Corporation (Norwest) was contracted by Great Northern Properties L.P. (GNP) to analyze and interpret existing data regarding coal properties controlled by GNP and the State of Montana, collectively referred to as the Otter Creek Property. The Otter Creek Property covers a large area within Powder River and Rosebud counties, Montana. The tract trends north to south and encompasses over 100 square miles of land.

The overall project objectives consisted of updating the geologic model and resource estimates, identifying specific logical mining units (LMUs), preparing documents that describe each LMU in terms of geology, available resources, coal quality, mineability, strip ratio and range of expected mining costs. An additional objective of this study was to assess the vertical variation of sodium in the Knoblock Seam and to assess the opportunity for selective mining in order to minimize variations in coal quality.

The Otter Creek Property is located in the Ashland coalfield east of Billings, Montana. The Otter Creek Property is located in Rosebud and Powder River Counties, Montana. The general location of the property is shown on Figure E.1.

GNP coal resources are located within the boundaries of the Custer National Forest and comprise alternating sections of property held in fee by GNP and public domain property held by the State of Montana.

The coal resources of the Otter Creek Property have been the subject of several investigations starting in the mid 1970's. This has resulted in numerous data sets developed by several corporate and government entities.



LEGEND Interstate Principal Highway Other Roads State Line County Line		Great Northern Properties, LLP	
		Figure E.1 Otter Creek Property Location Map	
DATE: 06/01/2005 PROJECT: 3187 FILE: 3187/Location		NORWEST CONSULTING	

The geologic data collected during the various programs amounted to more than 460 drill holes – these were utilized to characterize this resource.

The quantity of drilling that has been completed on the Otter Creek Property is sufficient to reasonably estimate overall coal tonnages in most areas within the property. The overall in-place resources are estimated at about 4.3 billion tons.

The coal averages 8,500 to 8,600 BTU/lb on an as-received basis. The high moisture content, which averages 27.5% to 28.0%, is fairly typical of Powder River Basin coals. The sulfur content of the coal is very low and with few exceptions the coal is classified as compliance coal, producing less than 1.2 pounds of SO₂/million BTU. The ash content of the coal is also low. The sodium content of the ash is considered high and averages between 6.0 and 7.0 percent.

Mine planning indicated the six discrete LMUs which are summarized in the table below.

Table E.1 LMU Summaries

LMU	Recoverable Tons (millions)	Moisture % (As-received)	Ash % (Dry Basis)	Sulfur % (Dry Basis)	Btu/lb (Dry Basis)	Sodium in Ash % (Dry Basis)
1	346	28.6	6.9	0.3	11,940	6.8-6.9
2	556	28.2	7.8-8.6	0.3-0.4	11,800-11,900	5.7-6.4
3	241	24.3	6.8	0.3	12,000	8.8
4	266	27.4	6.8	0.3	11,700-12,000	7.0-7.9
5	901	28.4	7.0-8.5	0.3	11,800-12,000	6.4-7.1
6	507	28.7	7.2-8.3	0.3	12,600	8.7-8.3

The coal quality data was analyzed to identify vertical variability within each major bench of the Knoblock seam. This indicated the following:

- An inverse relationship exists where the sodium content of the coal ash generally increases as the ash content decreases.
- Sulfur content however, is elevated in the top portion of the Upper Knoblock seam.
- Ash content is the highest in the top portions of all of the coal benches.
- The Upper Knoblock Seam is generally slightly lower in ash content and higher in Sodium Oxide than the lower portions of the Knoblock Seam.

Coal quality control programs and blending will likely be required during mining operations in order to maintain consistent product quality.

All LMUs are amenable to surface mining using draglines and truck-shovel fleets for overburden removal. These techniques are used at other mines in the region including Absaloka, Decker, Rosebud, and Spring Creek Mines. The smaller LMUs will require 70 to 80 cubic yard (CY) capacity draglines while the larger LMUs will need 110 to 120 CY draglines. The combined LMUs will require two draglines. For LMUs 1 through 4, the truck-shovel fleet will consist of 25 to 30 CY hydraulic excavators or shovels and 190 to 240 ton trucks.

When it is necessary to meet the customer's coal specifications, it may be possible to selectively mine the coal to improve the coal quality. The selective mining process removes zones within each seam that are usually higher in sulfur or sodium thereby resulting in a higher quality product.

The following table lists the production rates selected for the LMUs:

Table E.2 Production Rate by LMU

LMU	Yearly Production Rate (Tons)
1	8,500,000
2	12,700,000
3	6,000,000
4	6,000,000
5	21,200,000
6	12,000,000

Norwest developed an indicative mining cost estimate¹ for each LMU based on unit mining costs derived from actual and projected mining costs from mines having similar mining conditions. The average life-of-mine costs for the six LMU range from \$6.69 per ton to \$7.65 per ton. We also developed scoping capital costs for each LMU.

Montana coal, the Northern PRB, is noted for its heating value that is higher than most of the Southern PRB mines, its varying sulfur levels and its higher sodium levels. The sodium content of Otter

¹ Norwest recommends that additional engineering be performed to further refine the operating (and capital) costs.

Creek coal ranges from 5.8% to 8.8% and is high in comparison to other coals in the western US, but about the same as other Montana PRB mines. For example: coals from the southern Powder River Basin of Wyoming typically average 1.2% sodium while currently produced coals from Colorado average about 2.5% sodium.

Sodium in ash can cause slagging problems in certain types of boilers in electric generating plants. As a result, most plants avoid burning high sodium coals. However, we have identified ten power plants within the competitive area for Otter Creek which currently accept higher sodium coals. These plants would likely constitute the initial target market for Otter Creek coals. The information and data used to assess the marketing is derived from FERC data. It is, from our experience, the best data available but not much audited for accuracy of reporting nor input into their database and perhaps even suspect. Nevertheless, we were able to estimate current FOB prices for coal similar to Otter Creek.

It should be noted that the volume of coal shipped from Montana to the high sodium-accepting power plants is only about 20 million tons per year. Careful effort developing a solid market strategy will be necessary to determine how best to nudge into this market without destroying whatever price discipline, if any, currently exists. All Montana mines have been operating for many years and are experiencing higher stripping ratios in the range of 3-4:1 at Spring Creek, climbing up to 9:1 and higher at Decker. These higher strip ratios put these mines at a disadvantage with respect to Otter Creek's projected operating costs, as they each must move more waste to uncover the same amount of coal as at Otter Creek. This higher cost, however, will be offset by Otter Creek's higher capital recovery / depreciation costs.

At present there are no established transportation links to the Otter Creek property. We assessed the options of rail and truck transportation to the rail spur to the line at Colstrip, located about 38 rail miles distant. From Colstrip the trains would continue on to their final destination. While the rail option has a higher initial capital, this is offset in only a few years by the reduced transportation costs. Therefore, we recommend the rail alternative.

INTRODUCTION AND OBJECTIVES

Great Northern Properties L.P. (GNP) has contracted Norwest Corporation (Norwest) to analyze and interpret existing data regarding coal properties controlled by GNP and the State of Montana, collectively referred to as the Otter Creek Property. The Otter Creek Property covers a very large area within Powder River and Rosebud counties, Montana. The tract trends north to south and encompasses over 100 square miles of land.

The overall project objectives consisted of updating the geologic model and resource estimates, identifying specific LMU's, and to prepare documents that describe each LMU in terms of geology, available resources, coal quality, mineability, strip ratio and range of expected mining costs. An additional objective of this study was to assess the vertical variation of sodium in the Knoblock Seam and to assess the opportunity for selective mining in order to minimize variations in coal quality.

As part of this study, Norwest was required to build independent geologic and coal quality models. The key geologic components and tasks associated with preparing the models and satisfying the objectives of the study were established as follows:

- Prepare and merge two separate drill hole databases into one consolidated stratigraphic and coal quality database.
- Construct correlation charts to ensure that the merged data sets conform to the same stratigraphic nomenclature and that seam correlations were correctly identified.
- Prepare digital surfaces of the seam structure, thickness and basic coal quality parameters.
- Upon completion of the digital surfaces, prepare maps locating the position of the seam outcrop, subcrop and weathered surfaces.
- Create a geologic model of the coal resource area and calculate the coal tonnage and overburden volumes of the in-place resource.
- Identify the quality distribution of the coal both laterally and vertically within the seams.
- Assist with identifying LMU's that could be developed within the property.

This report summarizes the geologic modeling, resource estimates and coal quality characteristics. This information will form the basis of future LMU delineation and mineability studies.

GEOLOGY AND COAL RESOURCES

LOCATION, TOPOGRAPHY AND LAND USE

The Otter Creek Property is located in the Ashland coalfield east of Billings, Montana. Access to the property from Billings is available by traveling east on Interstate Highway 90 to the town of Crow Agency in the Crow Indian Reservation. From that point access is provided by traveling east on U. S. Highway 212 to a point four miles east of Ashland, Montana. Final access to and through the property is provided by traveling south on Otter Creek Road, an improved all-weather dirt road that leads from Highway 212 to the town of Otter, Montana at the south end of the Otter Creek Property as shown in Figure 2.1. Numerous unimproved dirt (2-track) roads provide local access within the Otter Creek Property.

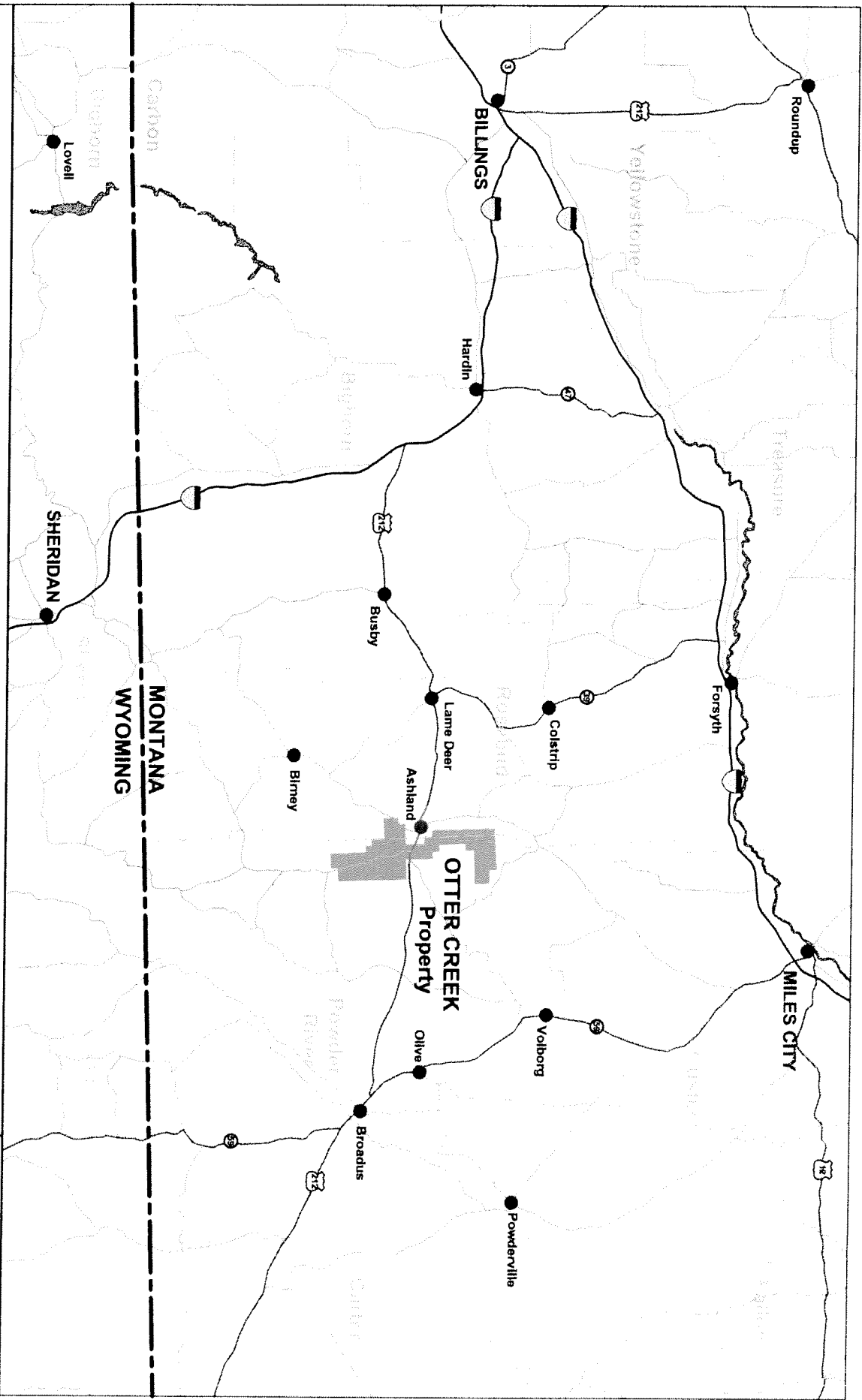
The Otter Creek Property is located in Rosebud and Powder River Counties, Montana. It is within the boundaries of the Custer National Forest but is comprised of alternating sections of property held in fee by GNP and public domain property held by the State of Montana. Coal ownership is illustrated in Appendix A, Map A2.1.

Topography in the area of the Otter Creek Property is characterized by rolling hills separated by broad valley regions. The rolling hills are covered by plains grasses and provide excellent rangeland for ranching and habitat for wildlife. Elevations within the property area range from less than 3,000 feet above sea level along Otter Creek that flows in a general north-south direction through the center of the property, to over 3,400 feet on the bluffs that flank Otter Creek.

DATA AND METHODOLOGY

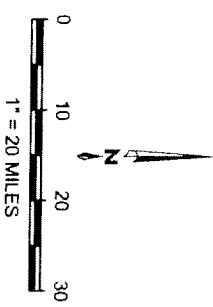
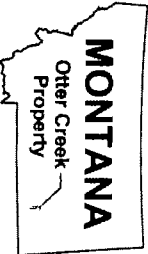
Data Sources

The coal resources of the Otter Creek Property have been the subject of several investigations starting in the mid 1970's. This has resulted in numerous data sets developed by several corporate and government entities. Early investigations include drilling conducted by the Montana Bureau of Mines and Geology, Consolidation Coal Company, City Services, and GNP.



LEGEND

- Interstate
- Principal Highway
- Other Roads
- State Line
- County Line



Great Northern Properties, LLP

Figure 2.1
Otter Creek Property
Location Map

Most recently, in 2004, Kennecott Energy and the State of Montana initiated an exploration program that included the drilling of 54 holes of which 42 were core drilled providing for coal samples that were analyzed for their quality.

In addition to the drill hole data, regional geologic information was used from published reports by the U. S. Geological Survey.

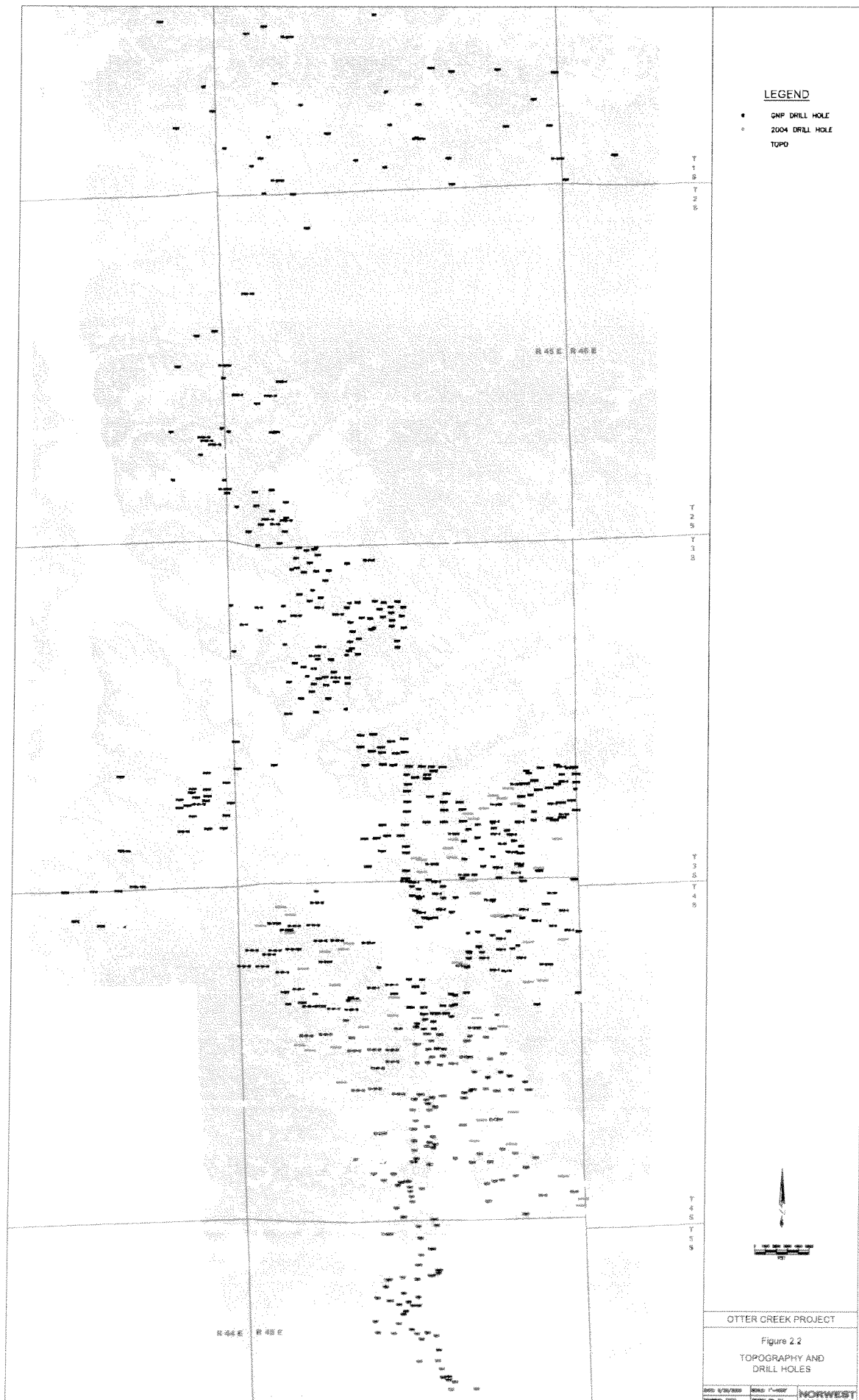
Nature of Geologic and Coal Quality Data

The geologic data collected during the programs described above have been provided to Norwest in electronic format. Several database files have been made available that contain pertinent information regarding the drill holes including hole location information, down-hole information including seam intercepts, coal thickness, in-seam rock partings, and coal quality data. In addition to this information, electronic copies of drill cutting and geophysical log records have been provided for many of the drill holes.

The exploration programs that have been conducted on the Otter Creek Property have provided extensive drill hole data that defines the coal resource potential of the property. The distribution of the drill holes that have been completed on the Otter Creek Property to date are shown in Figure 2.2 and Map A2.2.

All of the information provided to Norwest has been used to assess the accuracy of the data and to evaluate the resource potential of the Otter Creek Property.

As illustrated, over 460 drill holes have been utilized to characterize this resource. The distribution of drill holes across the property is uneven, with many concentrated in the central and southern portions of the property and generally fewer holes and more widespread coverage in the north. Additionally, there are many areas throughout the property that will require substantial drilling to accurately delineate the coal subcrop and burned zones.



Data Accuracy and Adequacy

Although the data provided to Norwest was in electronic format, it was in several different forms such as drill cutting/core logs, scanned geophysical logs, digital “las” files and tabulated drill hole data. This has allowed Norwest to make cross checks between the data represented on the cutting/core logs and geophysical logs with the various files of tabulated drill hole data. Where available, the data on the drill logs were compared against the tabulated data. This comparison indicated that the tabulated drill hole data were accurate and represented the data provided on the drill logs in their various forms.

The coal seam correlation and nomenclature used in the various data files were compared and checked to insure that the final data files were consistent in the seam correlation and in the naming of the seams present.

Geophysical logs were provided in electronic (las) format for holes drilled in 2004. Plots of these logs were prepared using Norwest’s “Pinnacle” in-house geologic software. Top and bottom depths of the coal seams shown on the logs were determined by selecting the mid-point on the deflection of the resistivity and gamma-gamma density log traces. These depths were compared with those listed on the tabulated data and it was found that the resulting coal thickness measurements listed on the tabulated data understate the coal thickness by an average of 1.5%. This suggests that the coal thickness measurements used in this report are slightly on the conservative side.

It is important to point out that the most reliable method of measuring coal thickness penetrated in a drill hole is through the analysis of geophysical logs. Coal thickness derived from core measurement is usually limited in accuracy by frequent crushing of the core and by core loss.

Methodology

After all drill hole data had been checked for accuracy, it was combined into two master Excel files. One file contained coal depth and thickness information and the other file contained coal quality data. These files were then used to develop the geologic model utilizing Carlson Engineering’s SurvCADD XML modeling software.

GEOLOGY AND MODELING RESULTS

The data files created by Norwest, described above, plus published data on coal deposits of the region enabled the development of a digital geologic model that accurately characterizes the coal resources present within the Otter Creek Property. The following section describes the coal deposit contained within the Otter Creek Property and the geologic model generated that represents these deposits.

Structure and Overburden

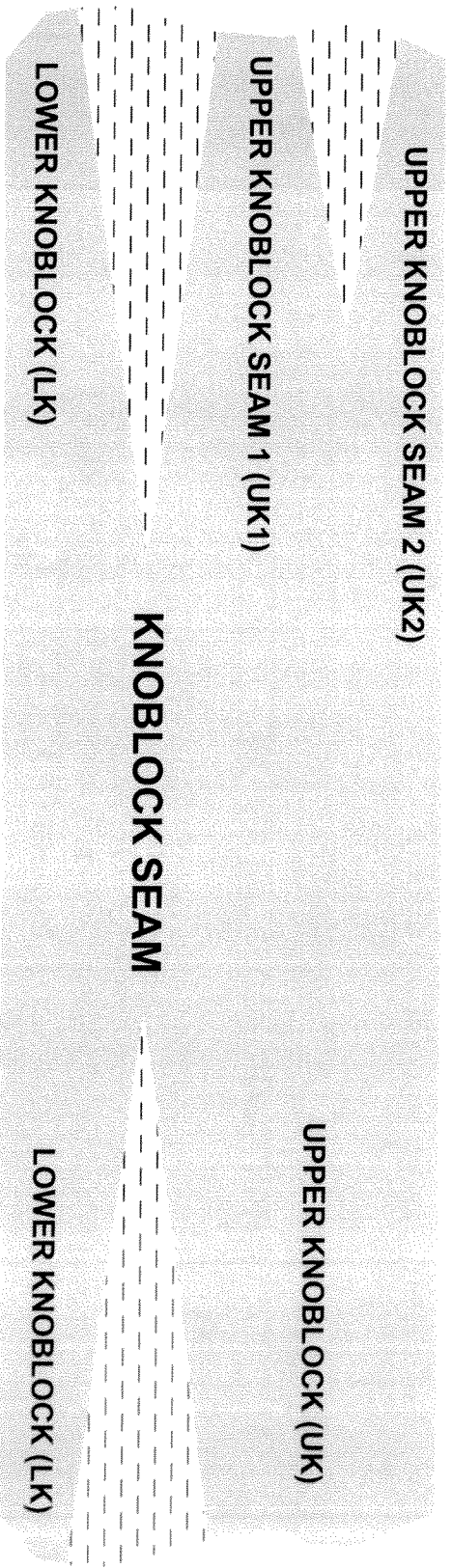
The Otter Creek Property lies in a region of the Powder River Basin that is structurally stable. No known faulting is present that dissects the coal seams within the property. The coal beds are nearly flat or gently dipping more as the result of depositional loading rather than tectonic deformation. The coal beds within the Otter Creek Property are very flat-lying having an average dip of one degree or less. Maps A2.3, Knoblock Seam Top Structure, and A2.4, Knoblock Seam Bottom Structure, illustrate the gently rolling structure of the property. These drawings, along with others that illustrate the geologic model, are presented in Appendix A of this report.

Stratigraphy

The coal seams of economic interest within the Otter Creek Property are contained within the Tongue River member of the Fort Union Formation of middle Paleocene age. The primary coal seam within the Otter Creek Property is the Knoblock (K) seam. This coal seam ranges in thickness from 19 feet to 75 feet and averages approximately 59 feet. The seam splits into two sub-seams, the Upper Knoblock (UK) and the Lower Knoblock (LK), in the southern and northern portions of the property. The Upper Knoblock splits again into two sub-seams in the extreme southern portion of the property. The upper sub-seam of this split is called the Upper Knoblock 2 (UK2) seam while the lower sub-seam is called the Upper Knoblock 1 (UK1) seam. Figure 2.3 below illustrates the relationship of the coal seam splits. The correlation of the sub-seams in the areas where the Knoblock splits is well defined by the drilling that has been completed.

Map A2.5 Drill Hole Correlation Charts, located in Appendix A, illustrates the relationship of the sub-seams within the property. It is important to point out that the thickness represented on the Isopach map represents the same interval used in the quality modeling for a given drill hole. Intervals of bone coal near the top or bottom of the coal seam were excluded in the thickness used to develop the Isopach map.

SOUTH



NORTH

Great Northern Properties, LLP

Figure 2.3
Otter Creek Property
Generalized Cross-Section

DATE: 08/01/2005	PROJECT: 3187	NORWEST CORPORATION
FILE: knoblockseam.doc		

The Knoblock seam is thickest in the central area of the Otter Creek Property as shown on Map A2.6 Knoblock/UK/UK2 Seam Isopach. Also shown on this map is the thickness and extent of the Upper Knoblock 1 and 2 seams. In the northern area of the Otter Creek Property where the Knoblock seam is split into two sub-seams (UK and LK), the thickness of the parting or interburden that separates the two sub-seams generally increases in a northerly direction. Likewise, in the southern portion of the property, this interburden increases in thickness in a southerly direction. Map A2.7, illustrates the thickness of this interburden. The coal thickness of the Upper Knoblock 1 seam, the Lower of the sub-seams formed by the splitting of the Upper Knoblock seam in the extreme northern and southern portions of the property, is illustrated on Map A2.8, Upper Knoblock Seam 1 Isopach. The thickness of the interburden that separates the Upper Knoblock 1 seam from the Upper Knoblock 2 seam is illustrated on Map A2.9. The thickness of the Lower Knoblock seam, present in both the northern and southern portions of the Otter Creek Property, is illustrated on Map A2.10.

The coal seams present are covered by overburden consisting of interbedded fine-grained sandstones and mudstones. The thickness of the overburden is variable due to topography in the area. The overburden thickness has been modeled by subtracting the elevation of the top of the coal seam from the topographic elevation. This overburden thickness is illustrated on Map A2.11 Knoblock Seam Overburden Isopach.

Outcrop, Zone of Weathering and Burned Coal

Outcrops of the Knoblock seam and sub-seams are present on both sides of Otter Creek, which flows in a northerly direction through the center of the property and exits the property's western boundary near the town of Ashland. A zone of weathered or burned coal normally exists where the seam is found at near-surface depths. This zone of weathering was identified from observations recorded in drill hole lithologic logs. The zone's thickness is variable and ranges from as little as five feet in the southern portion of the property to over 150 feet in the northern portion of the property. After the zone of weathering had been identified in all of the drill holes, the zone was modeled by preparing a thickness grid. This thickness grid was then subtracted from the surface topography which resulted in an elevation grid representing this "weathered surface". The "weathered surface" is illustrated on Map A2.3, Drill Hole Location Map and Coal Seam

Correlation Cross-Sections. Where the modeled zone of weathering intersected the coal seam, the limit of that coal seam was trimmed to the base of the weathered zone to form a subcrop line. This subcrop line was transferred onto the resource maps that were used in calculating the tonnage of in-place coal resources. Of particular note is that for each coal bench or seam, two weathering lines were generated, one representing the intersection of the weathered surface with the top of the seam and the other the seam base. The importance of the two lines is the fact that with coals of this thickness, there are many instances when only top portions of the seam may be weathered while the lower portions are not.

In addition, after delineating the subcrop limits by the method described above, Norwest overlaid the prior representation of a burn line which was provided by GNP. It is apparent that this burn line was generated by sketching a representation of the burn area through drill holes which encountered coal burn and those that encountered un-weathered coal. It is expected that this “burn line” was determined through inspection of aerial photographs, though this has not been verified by Norwest.

Norwest compared the “zones of weathering” with the GNP “burn line”. In general, the areas and lines compared well. It should be clearly noted that across the property the depth of weathering and areas of “burned” coal has been delineated to highly varying degrees of accuracy, based on the variable drill hole density. In-place resource estimations and in-place stripping ratios are very sensitive and dependent upon the degree of confidence of this weathering or burn zone. Prior to actual development of these properties, substantial amounts of additional drilling is warranted to verify the actual weathering limits.

RESOURCE ESTIMATION

The quantity of drilling that has been completed on the Otter Creek Property is sufficient to reasonably estimate overall coal tonnages in most areas within the property. Several areas, particularly in the north, warrant additional drilling. Norwest’s estimates of resources are presented in two categories of tonnage within the property boundaries. These categories are referred to as *in-place resources* and *speculative resources*. Map A2.12 presents the in-place resources and associated coal quality by section. Also illustrated on this drawing are the subcrop line of the base of the Knoblock coal and the GNP burn line.

In-place resources as defined by Norwest include all resources that are delimited by the burn line and exist within a high degree of confidence resulting from a certain drill hole density, while the speculative resources are those that are projected between the GNP burn line and the projected subcrop line of the Lower Knoblock Seam. These speculative resources would consist of areas that may contain partially burned or oxidized coal. The areas containing these speculative resources are illustrated by shading on Maps A2.12 and A2.13. Norwest believes that it is very likely that substantial resources of this type exist but will require additional drilling to verify tonnage and specific locations.

Coal resources were calculated by measuring the volume of coal represented by the coal seam thickness intervals shown on the coal seam Isopach maps, limited by the subcrop lines formed by the intersection of the coal seam and the zone of weathering. The volume of coal was then converted to tons of coal by multiplying the volume by the factor of 77.6 pounds of coal per cubic foot. Table 2.1, Otter Creek Property, Coal Resource Summary found below, summarizes the coal resources classified by ownership. It provides the defined tons which are limited by the weathering zone on Map 2.3. Table 2.1 also lists speculative resources that represent resources that may be oxidized or partially burned. Again, additional outcrop drilling is needed to define this category of resources.

Table 2.1 represents the summary of an in-depth analysis of the coal resources present within the Otter Creek Property. Several detailed tables were generated in the analysis process, copies of which can be found in Appendix B. Included within these tables are detailed classifications of resources according to the USGS Circular 891, illustrating the Measured, Indicated and Inferred categories of reliability. Map A2.14 illustrates the data distribution and the resource classification areas.

Coal resources were calculated for the three prime mining tracts; Otter Creek Tract 1, Otter Creek Tract 2 and Otter Creek Tract 3. Table 2.2, Otter Creek Property - Resource Summary of Tracts 1, 2, and 3 summarizes the coal resources by tract and by landowner within each tract. With the exception of one small 162 acre tract, all the coal is controlled by GNP or the State of Montana. Figure 2.4, Coal Ownership Map, Otter Creek Tracts 1, 2, and 3 show the location of these the prime development tracts.

Otter Creek Property Resource Summary
Table 2.1, Total, Inplace and Speculative Resources

Ownership	Total Resources			In-place Resources			Speculative Resources		
	Acres	Waste (bcy)	Coal Tons	In-Place Ratio (CY/ton)	Acres	Waste (bcy)	Coal Tons	Waste (bcy)	Coal Tons
Total	62,034	16,201,371,882	4,324,951,299	3.7	51,305	14,326,037,698	3,767,763,101		
State of Montana	12,551	3,669,435,534	1,056,225,648	3.5	10,742	3,357,323,849	948,900,268	1,875,934,183	557,188,198
Great Northern Properties	30,565	8,131,739,475	2,210,372,841	3.7	25,207	7,201,172,150	1,944,144,965	312,111,685	107,325,380
Other (Federal, Private, etc.)	18,918	4,400,796,872	1,058,352,810	4.2	15,356	3,767,541,699	874,717,868	930,567,325	266,227,876
								633,255,173	183,634,942

Coal Ownership Summary																	
TR	SECTION	Coal Ownership	Area	GWP	Status of Ownership	Mileage (Miles)	Coal Tonnage	In-Pit Ratio (MC/WOM)	Total Resources			Specialty Resources			In-Pit Resources		
									EQ Reserves	Sub-Basin (%)	Acres (%)	MC Reserves	% to Acre	Acres	WOM Reserves	Acres	WOM Reserves
10	State of Montana	10	10	0	0	0	23,500,831	3.8	24.54	29.25	1,850	1,850	10,333,514	81	10,333,514	10,333,514	81
11	State of Montana	11	11	0	0	0	23,500,831	3.8	24.54	29.25	1,850	1,850	10,333,514	81	10,333,514	10,333,514	81
12	State of Montana	12	12	0	0	0	23,500,831	3.8	24.54	29.25	1,850	1,850	10,333,514	81	10,333,514	10,333,514	81
13	State of Montana	13	13	0	0	0	23,500,831	3.8	24.54	29.25	1,850	1,850	10,333,514	81	10,333,514	10,333,514	81
14	State of Montana	14	14	0	0	0	23,500,831	3.8	24.54	29.25	1,850	1,850	10,333,514	81	10,333,514	10,333,514	81
15	State of Montana	15	15	0	0	0	23,500,831	3.8	24.54	29.25	1,850	1,850	10,333,514	81	10,333,514	10,333,514	81
16	State of Montana	16	16	0	0	0	23,500,831	3.8	24.54	29.25	1,850	1,850	10,333,514	81	10,333,514	10,333,514	81
17	State of Montana	17	17	0	0	0	23,500,831	3.8	24.54	29.25	1,850	1,850	10,333,514	81	10,333,514	10,333,514	81
18	State of Montana	18	18	0	0	0	23,500,831	3.8	24.54	29.25	1,850	1,850	10,333,514	81	10,333,514	10,333,514	81
19	State of Montana	19	19	0	0	0	23,500,831	3.8	24.54	29.25	1,850	1,850	10,333,514	81	10,333,514	10,333,514	81
20	State of Montana	20	20	0	0	0	23,500,831	3.8	24.54	29.25	1,850	1,850	10,333,514	81	10,333,514	10,333,514	81
21	State of Montana	21	21	0	0	0	23,500,831	3.8	24.54	29.25	1,850	1,850	10,333,514	81	10,333,514	10,333,514	81
22	State of Montana	22	22	0	0	0	23,500,831	3.8	24.54	29.25	1,850	1,850	10,333,514	81	10,333,514	10,333,514	81
23	State of Montana	23	23	0	0	0	23,500,831	3.8	24.54	29.25	1,850	1,850	10,333,514	81	10,333,514	10,333,514	81
24	State of Montana	24	24	0	0	0	23,500,831	3.8	24.54	29.25	1,850	1,850	10,333,514	81	10,333,514	10,333,514	81
25	State of Montana	25	25	0	0	0	23,500,831	3.8	24.54	29.25	1,850	1,850	10,333,514	81	10,333,514	10,333,514	81
26	State of Montana	26	26	0	0	0	23,500,831	3.8	24.54	29.25	1,850	1,850	10,333,514	81	10,333,514	10,333,514	81
27	State of Montana	27	27	0	0	0	23,500,831	3.8	24.54	29.25	1,850	1,850	10,333,514	81	10,333,514	10,333,514	81
28	State of Montana	28	28	0	0	0	23,500,831	3.8	24.54	29.25	1,850	1,850	10,333,514	81	10,333,514	10,333,514	81
29	State of Montana	29	29	0	0	0	23,500,831	3.8	24.54	29.25	1,850	1,850	10,333,514	81	10,333,514	10,333,514	81
30	State of Montana	30	30	0	0	0	23,500,831	3.8	24.54	29.25	1,850	1,850	10,333,514	81	10,333,514	10,333,514	81
31	State of Montana	31	31	0	0	0	23,500,831	3.8	24.54	29.25	1,850	1,850	10,333,514	81	10,333,514	10,333,514	81
32	State of Montana	32	32	0	0	0	23,500,831	3.8	24.54	29.25	1,850	1,850	10,333,514	81	10,333,514	10,333,514	81
GRAND TOTAL			6,869	3,115	3,363	162	2,881,811,314	678,967,031	3.8	34.17	28.35	11,850	12,840	7.22	936	1,839,367,711	1,839,367,711
TOTAL GWP			3,112				819,487,586	320,871,221	3.8	24.13	21.48	9,098	9,746	5.57	164	27,617,203	27,617,203
TOTAL STATE OF MONTANA			3,362				1,023,771,566	328,328,116	3.1	24.22	28.30	11,384	12,840	7.21	371	71,969,348	71,969,348
TOTAL PRIVATE			162				18,169,246	18,169,246	1.1	24.14	27.54	1,182	1,240	6.38	0	0	0
TOTAL FEDERAL																	

GRAND TOTALS FOR TRACT 1, TRACT 2 AND TRACT 3

GRAND TOTAL	18,181	9,084	8,826	182	5,081,546,177	1,104,219,104	3.0	24.25	27.84	7.07	0.28	11,987	12,865	7.48	2,111	364,224,985	120,093,222	18,070	4,687,313,193	1,506,123,862
TOTAL GNP	9,084				2,368,816,675	842,952,028	2.8	24.25	25.33	6.43	0.25	10,802	11,817	6.67	916	154,991,259	52,112,858	5,118	2,213,925,417	789,839,172
TOTAL STATE OF MONTANA	8,825				2,674,671,813	847,101,383	3.2	24.25	27.80	7.02	0.28	11,874	12,868	7.60	1,135	209,335,727	66,983,367	7,790	2,464,935,086	780,116,017
TOTAL PRIVATE	162				18,551,890	16,185,693	1.1	24.14	27.54	7.85	0.32	11,872	12,840	6.39	9	0	0	162	18,551,890	16,185,693

COAL QUALITY

The coal resources contained within the Otter Creek Property are sub-bituminous in rank. Quality data have been made available through the analysis of core samples from 115 drill holes completed on the Otter Creek Property in the various drilling programs since the early 1970's. These data have defined the quality of the coal present within the property. The quality database contains proximate analysis, ultimate analysis, mineral analysis of ash, and in some cases equilibrium moisture analysis and density.

Quality Modeling

In general, core samples of coal from a given drill hole were sampled and analyzed in zones ranging from less than one foot to as much as ten feet in thickness. In some cases, these samples were combined to produce a physical composite. Because not all holes had physical composite samples, calculated mathematical composites were used for each of the drill holes containing quality data. These calculated values were double-weighted for both interval thickness and density. Where physical density data were not available for a sample this value was calculated using a linear regression analysis of the ash/density relationship of all samples having both data sets. A comparison of several physical composites with calculated composites of the same interval was made which validated that the composite method was accurate. Numerous tables of coal quality data were generated in the process of reducing the quality data. These intermediate stage tables are presented as back-up material and can be found in Appendix C.

The Knoblock coal averages 8,500 to 8,600 BTU/lb on an as-received basis. The high moisture content, which averages 27.5% to 28.0%, is fairly typical of Powder River Basin coals. The sulfur content of the coal is very low and with few exceptions the coal is classified as compliance coal, producing less than 1.2 pounds of SO₂/million BTU. The ash content of the coal is also low. Table 2.3 Otter Creek Property Coal Quality Summary, lists the statistics for selected parameters by seam.

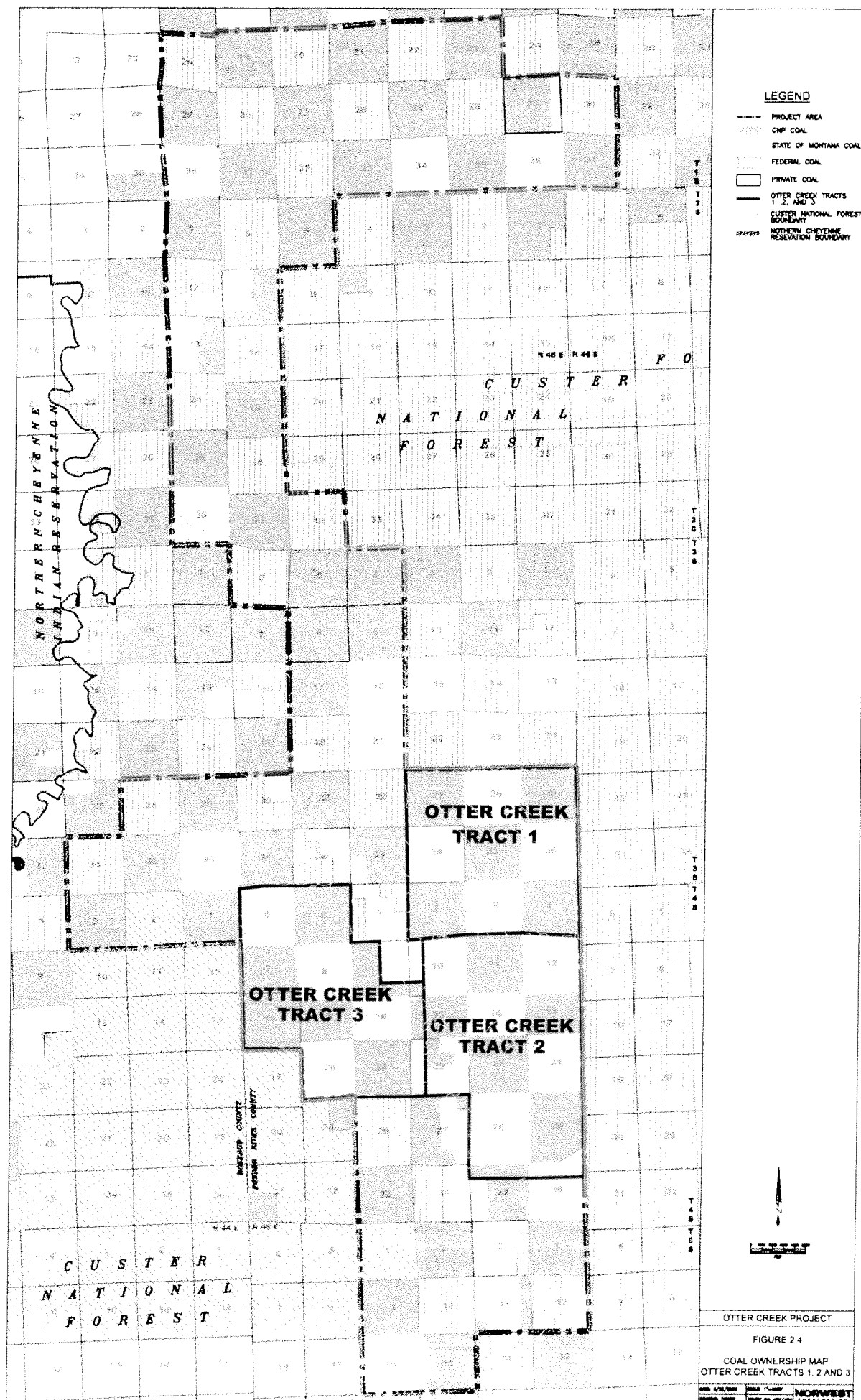


TABLE 2.3: OTTER CREEK PROPERTY COAL QUALITY SUMMARY

Upper Knoblock Seam												
	Thickness	Moisture	Ash	AS Received Density	BTU/Lb	Sulfur	Lb SO ₂ /mmBTU	NaO	Lb NaO/mm BTU	Dry BTU/Lb	MAF BTU/Lb	
Min	2.0	22.39	3.32	1.22	6,798	0.12	0.29	0.73	0.00	9,345	11,238	
Max	51.5	31.21	21.01	1.41	9,310	1.58	26.59	10.46	3.21	12,327	13,154	
Mean	35.4	27.28	5.50	1.24	8,651	0.27	1.04	6.61	0.37	11,906	12,847	
St. Dev.	16.6	2.29	5.70	0.06	979	0.48	11.87	2.82	1.39	1,334	1,083	
Knoblock Seam												
	Thickness	Moisture	Ash	AS Received Density	BTU/Lb	Sulfur	Lb SO ₂ /mmBTU	NaO	Lb NaO/mm BTU	Dry BTU/Lb	MAF BTU/Lb	
Min	3.6	24.21	3.48	1.22	5,806	0.09	0.20	0.02	0.00	8,896	10,235	
Max	72.2	36.35	33.73	1.55	9,372	0.77	2.40	10.96	40.99	12,748	14,189	
Mean	60.5	28.04	5.09	1.24	8,594	0.20	0.47	7.03	0.49	11,946	12,843	
St. Dev.	11.4	2.99	7.10	0.08	883	0.24	0.71	2.56	11.11	1,174	765	
Lower Knoblock Seam												
	Thickness	Moisture	Ash	AS Received Density	BTU/Lb	Sulfur	Lb SO ₂ /mmBTU	NaO	Lb NaO/mm BTU	Dry BTU/Lb	MAF BTU/Lb	
Min	10.2	25.46	4.05	1.23	5,233	0.16	0.37	3.57	0.26	7,152	8,423	
Max	22.7	31.10	18.99	1.39	8,804	0.46	3.67	10.46	2.94	12,191	13,207	
Mean	16.4	27.68	6.97	1.26	8,325	0.27	0.80	6.01	0.56	11,534	12,702	
St. Dev.	3.8	1.96	6.39	0.07	881	0.09	1.22	2.36	0.85	1,244	715	

As shown on Table 2.3, the sodium content of the ash is considered high and averages between 6.0 and 7.0 percent. An inverse relationship exists in Powder River Basin coals where the sodium content of the coal ash generally increases as the ash content decreases. This relationship is strongly evident in the data regarding this coal. The higher sodium values are not surprising because of the low average ash content of the coals.

The calculated composite quality data were used to generate a quality model of the coal resources found within the property. This is important to identify the lateral variability in quality over the property and to visualize the spacing of data. Maps A2.15 and A2.16 illustrate the distribution of the in-place moisture of the Knoblock coal benches on an as-received quality basis. The moisture content of the coal shows little variability in all of the seams.

One noteworthy point is the lack of quality data in the northern portion of the property. The area north of the north half of Township 2 South, the area where the Knoblock seam splits into the Upper and Lower Knoblock seams, has no quality data. Core drill holes will need to be completed to characterize the quality of the coal in this area.

The ash content of the coal on a dry basis has been modeled and is shown on Maps A2.17 and A2.18. As can be seen on Map A2.17, the ash content of the Knoblock and Upper Knoblock seams is uniformly low but Map A2.18 shows a high ash zone (26.5%) in the Lower Knoblock seam. This zone is a one-drill hole anomaly and may be an isolated zone that is likely to be not representative of the ash content throughout the area.

The sulfur content of the coal is shown on Maps A2.19 and A2.20. Both these maps illustrate the consistently low nature of the sulfur content within the property.

The calorific value of the coal on a dry basis has been modeled and is illustrated on Maps A2.21 and A2.22. The MAF BTU value has also been modeled and is illustrated on Maps A2.23 and A2.24. These maps demonstrate the consistent nature of the coal regarding its heat value content. The only exception to this is a one drill hole anomaly in both the MAF and Dry BTU of the Lower Knoblock seam in the same area that showed elevated ash content. Because the MAF BTU is lower than adjacent holes the coal in this drill hole may be oxidized.

The sodium content in the coal ash has been modeled and is illustrated on Map A2.25 Knoblock/Upper Knoblock Sodium and Map A2.26 Lower Knoblock Sodium. Both of these maps show greater lateral variability than is shown on any of the other parameters modeled. A comparison of the maps regarding dry ash content, Maps A2.17 and A2.18 with the sodium content, Maps A2.25 and A2.26 show the areas having low ash coincide with the areas having the highest sodium content. The area of high ash illustrated on Map A2.18 is shown to have much lower sodium content (2.0%) than any holes surrounding it. It is evident from these data that when this coal property is mined, care in blending will be required to minimize the variability in the sodium content of the coal that would be produced. In addition, it is evident that additional drilling data will be required to implement coal quality programs.

Limited data were available regarding the equilibrium moisture of the coal. These data were used to model the variability in the equilibrium moisture and are illustrated on Map 2.27. Most of the equilibrium moisture data are from drill holes in the southern portion of the property but north of the zone where the Knoblock and Lower Knoblock split apart. The equilibrium moisture shows little variability but more data should be collected regarding this, particularly in the northern portion of the property.

Vertical Variability

The coal quality data was analyzed to identify vertical variability within each major bench of the Knoblock seam. This was done in two ways. First, a statistical approach was taken to assess variability in a general sense. Secondly, quality plots were generated for each hole in order to visually review the distribution of quality parameters from each individual drill hole.

For the statistical approach the coal quality data from each hole and seam were classified as to the relative position in each coal bench; the roof coal (the upper most sample in the drill hole), the upper half of the seam below the roof coal (the samples below the roof coal sample through the middle sample within the seam), the lower half of the seam above the floor coal (samples extending below the mid point of the seam down to but not including the bottom sample in the seam), and the floor coal (the lowest sample within the seam). These samples were then statistically analyzed. A summary of this investigation is presented in Table 2.4 Otter Creek Property - Coal Quality Vertical Comparison.

TABLE 2.4: OTTER CREEK PROPERTY - COAL QUALITY VERTICAL COMPARISON

	Thickness	AS Received				Sulfur	Lb SO ₂ / mmBTU	NaO	Lb NaO/ mm BTU	Dry BTU/Lb	MAF BTU/Lb
		Moisture	Ash	Density	BTU/Lb						
Upper Knoblock Seam Quality Data											
Roof Coal	2.30	26.48	8.83	1.28	8,282	0.89	8.49	4.65	1.06	11,310	12,489
Upper 1/2 Below	18.91	27.49	4.64	1.23	8,736	0.22	0.51	6.74	0.31	12,051	12,869
Lower 1/2 Above	16.86	27.08	6.04	1.25	8,611	0.25	0.62	6.71	0.34	11,821	12,872
Floor Coal	1.79	27.97	4.96	1.24	8,615	0.25	0.58	6.90	0.33	11,966	12,841
Knoblock Seam Quality Data											
Roof Coal	2.43	26.75	9.50	1.29	8,211	0.47	1.22	5.54	2.87	11,242	12,785
Upper 1/2 Below	29.70	28.19	4.42	1.23	8,642	0.15	0.36	7.56	0.37	12,032	12,822
Lower 1/2 Above	25.14	27.97	5.27	1.24	8,597	0.19	0.44	6.60	0.38	11,938	12,871
Floor Coal	1.99	28.35	7.16	1.26	8,338	0.54	1.34	6.47	0.78	11,664	12,885
Lower Knoblock Seam Quality Data											
Roof Coal	1.97	25.74	9.80	1.29	8,315	0.35	0.86	4.32	0.47	11,217	12,899
Upper 1/2 Below	8.59	27.95	6.17	1.25	8,270	0.19	0.55	5.79	0.52	11,497	12,566
Lower 1/2 Above	4.86	27.80	7.61	1.27	8,335	0.29	1.05	6.91	0.70	11,576	12,756
Floor Coal	1.40	28.41	5.47	1.24	8,642	0.61	1.40	6.71	0.41	12,077	13,070

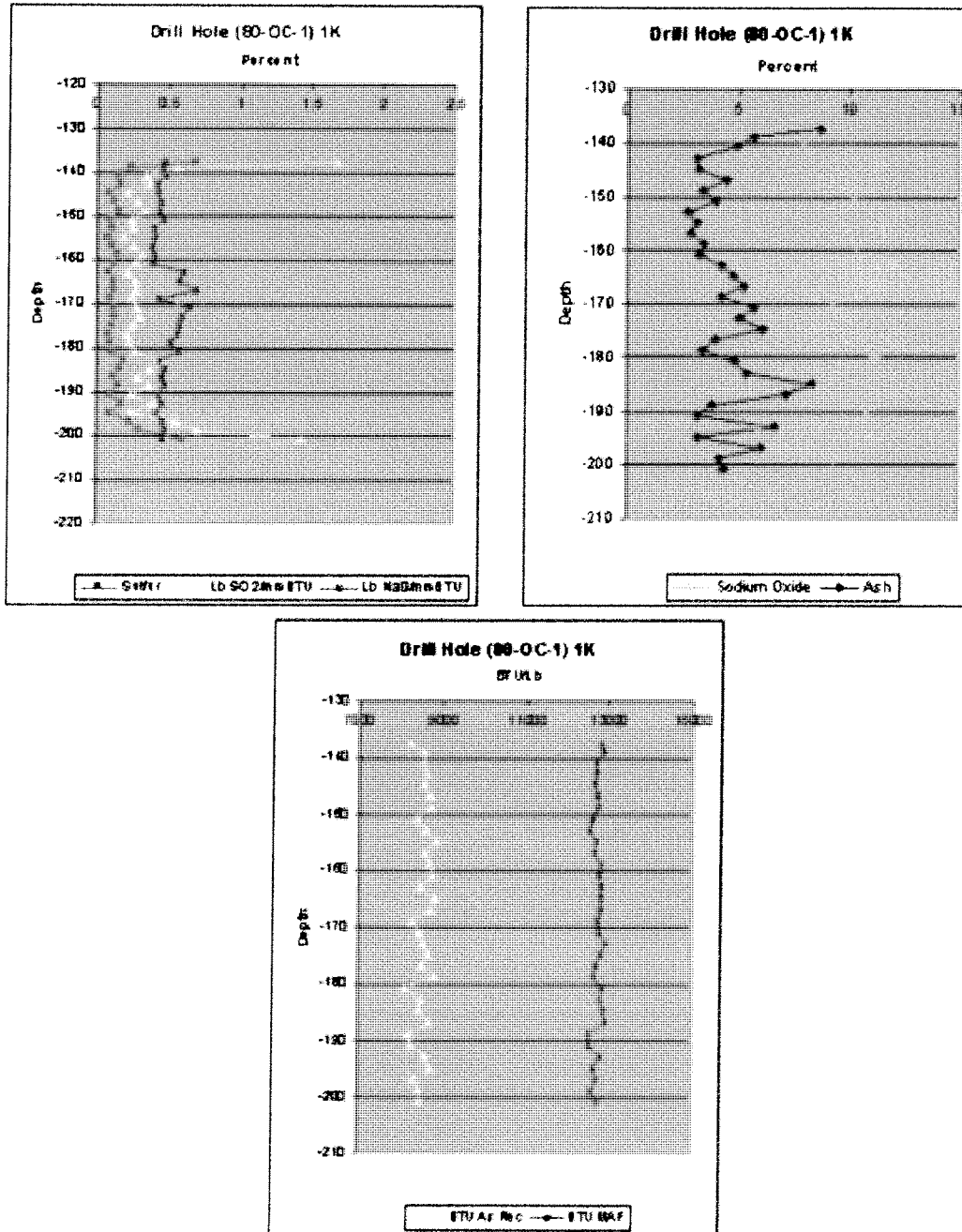
This comparison indicates the following:

- An increase in ash content in the roof and floor samples of all seams.
- The lower half of the Knoblock seam has a tendency to have higher ash content than the upper half.
- The Lower Knoblock is also higher in ash than the upper half of the Knoblock seam. This is not surprising because that portion of higher ash Knoblock is correlative to the Lower Knoblock seam.
- Correspondingly, the sodium oxide content is generally lower in the top portions of the benches and increases downward
- The lower ash portions of the seams generally contain the highest sodium oxide levels.
- The roof coal, due to its reduced calorific values, demonstrates elevated LB SO₂/mmBTU values.

The second way in which the quality data was reviewed vertically was to plot graphs of selected quality parameters with depth. Up to three graphs were generated for each drill hole containing quality data and have been plotted for a comparison of the vertical quality variation within each drill hole. Figure 2.5, Example Graphs of Coal Quality by Drill hole, illustrates how this quality data has been prepared. Similar graphs for all holes containing quality data are found in Appendix D. These graphs illustrate the tendency for the coal seams to have higher ash content in their roof and floor and as a result they also tend to have lower BTU value in these zones. The inverse relationship between the ash content and the sodium content in the ash is also very evident in most of these graphs.

Figure 2.5 Example Coal Quality Vertical Distribution

Hole 80-01-1 Knoblock Seam



Summary Conclusions and Opportunities Related to Blending

The primary conclusions derived from the lateral coal quality modeling and the review of the vertical variability of coal quality parameters are as follows:

- The coal averages 8,500 to 8,600 BTU/lb of coal on an as-received basis.
- Moisture content which averages 27.5% to 28.0% is fairly typical of Powder River Basin coals.
- The sodium content of the ash is considered high and averages between 6.0 and 7.0 percent.
- An inverse relationship exists where the sodium content of the coal ash generally increases as the ash content decreases.
- The sulfur content of the coal generally is consistently low, averaging approximately 0.27 % and with few exceptions, the coal is classified as compliance coal which produces less than 1.2 pounds of SO₂/million BTU.
- Sulfur content however, is elevated in the top portion of the Upper Knoblock seam.
- Ash content is the highest in the top portions of all of the coal benches.
- The Upper Knoblock Seam is generally slightly lower in ash content and higher in Sodium Oxide than the lower portions of the Knoblock Seam.
- Coal quality control programs and blending will need to be implemented during mining operations in order to maintain consistent product qualities.
- The opportunities for blending will need to be assessed on specific mining block areas as opposed to generalities applied to the entire Otter Creek project area.

MINING EVALUATION

Based on advice from GNP and the State of Montana, Norwest's focused our evaluation on the southern portion of the property because it is the most attractive for development from both resource and land control perspective. In this southern area, GNP and the State of Montana control the majority of the coal resources. In addition, the exploration drill hole density provides sufficient data to do a good evaluation of this property.

Norwest mining engineers evaluated the mineability of the Otter Creek coal resources by considering the topography, surface features, overburden depths, the thickness and dip of coal seams, the strip ratios, and coal outcrop lines. The geological investigation produced a series of maps showing these features and can be found in Appendix A to this report.

LOGICAL MINING UNITS

Norwest divided the southern portion of the Otter Creek reserve into a total of six LMUs. An LMU is an area of land in which the coal resources can be developed in an efficient, economical, and orderly manner as a unit with due regard to conservation of coal reserves and other resources. An LMU may consist of Federal leaseholds, private land, state lands combined under the effective control of a single operator that can be developed and operated as a single operation.

For the this study, each LMU has the following properties;

- Minimum of 200 million tons (Mt) of coal
- Maximum in-situ stripping ratio of 5:1 (five cubic yards of waste per ton of coal)
- Can be developed and operated as a single operation
- Can be separated from adjacent LMUs by physical boundaries such as stream channels, ridge lines or other naturally occurring barriers
- Sufficient resources for a minimum of a 40 year life.

In reality, all identified LMUs have more than 200 million tons of coal in-place, so that high-production, long-term mine plans could be developed. Reserves of this size are more likely to be attractive to major coal producers and energy project sponsors interested in

developing these resources. Table 3.1, LMU Reserves lists six LMUs with their related resource information. The LMUs are shown on Figure 3.1, LMU Map².

LMU 1 – Area A1

This LMU is located in Township 3S, Range 45 E, Sections 25, 26, 33, 34, 35 and 26 and Township 4S, Range 45 E, Sections 1, 2, and 3 and comprises the A1 mining area. It covers approximately 3,500 acres. At a maximum in-place strip ratio of 5:1, this LMU contains 355 million tons in two main seams. The average effective strip ratio, assuming 95% recovery, is 3.0:1 in place. Heat content averages 12,820 Btu (air dried basis), while sodium in ash averages 6.9 %.

There is a possible alluvial valley floor (AVF) lying on the south side of this LMU that contains 9 million tons of coal. This is shown separately to recognize that mining could possibly be restricted from this area, should it be classified as an AVF by the State.

Mining operations would primarily follow the strike of the coal outcrop, i.e., in a north-south and a northeast-southwest direction and advance easterly from the outcrop to the lease boundary. In the northern most portion of this LMU (Area A1), mining cuts are oriented north-south and northeast-south to take advantage of coal outcrop.

LMU 2 – Area A2 – A3

This LMU borders on the south of LMU 1 and lies primarily within Township 4S, R45E Sections 1, 2 10, 11, 12, 13, 14, 15, 22, 23, 24, 25 ,26, 35 and 36. It covers 5,000 acres and contains 510 million tons of coal at an average effective strip ratio of 2.8:1. Average heating content is 11,956 Btu (air dried basis), and sodium in ash averages 7.2%.

² Please note that only LMUs 1 through 4 are actually indicated on Figure 3.1. LMU 5 is a combination of LMUs 1 and 2 while LMU 6 is a combination of LMUs 3 and 4.

Table 3.1 Great Northern Properties LMU Reserves

Mine Block	Waste Volumes (bcy)	Volumes (bcy)	In-Situ Tons (tons)	Recoverable Tons (tons)	Equilibrated Moisture (%)	As Received Moisture (%)	INSITU COAL QUALITY				Sodium in the Ash (%)	Shipping Ratio		Annual Production 40 Year Mine Life	
							Ash (%)	DRY Sulfur (%)	Bitu (ton/ft)	Moisture - Ash Free Bitu (ton/ft)		Virgin (bcy : ton)	Effective (bcy : ton)		
LMU 1 AREA A1															
AREA A1 MAIN PIT	1,015,013,620	338,808,767	354,936,064	337,189,261	24.35	28.61	6.89	0.26	11,956	12,819	6.91	2.87	3.02	8.4	
AREA A1 J AVF	8,896,612	8,527,977	8,931,909	8,487,213	24.51	28.53	6.93	0.26	11,956	12,844	7.21	1.00	1.05	0.2	
TOTAL AREA A1	1,024,910,233	347,336,744	363,869,973	345,676,475	24.36	28.61	6.89	0.26	11,956	12,820	6.92	2.82	2.97	8.6	
LMU 2 AREA A2 AND A3															
AREA A2 and AREA A3	1,479,564,664	509,314,665	533,558,043	506,880,141	24.18	28.26	7.18	0.28	11,966	12,876	7.26	2.77	2.92	12.7	
AREA A2 AVF	46,593,276	40,029,643	41,935,054	39,838,302	24.21	27.84	7.45	0.30	11,917	12,847	6.87	1.11	1.17	1.0	
AREA A3 AVF	13,702,141	8,936,843	9,362,236	8,894,125	23.52	26.91	7.40	0.31	11,575	12,511	4.90	1.46	1.54	0.2	
TOTAL AREA A2 AND A3 COMBINED	1,539,860,082	558,281,151	584,855,334	556,612,567	24.17	28.21	7.21	0.29	11,956	12,868	7.19	2.63	2.77	13.9	
LMU 3 AREA B1															
AREA B1	777,596,175	242,065,305	253,587,614	240,908,233	24.30	26.84	6.77	0.27	12,012	12,881	8.74	3.07	3.23	6.0	
LMU 4 AREA B2															
AREA B2	596,618,818	239,853,272	251,270,288	238,206,773	24.21	27.40	7.38	0.29	11,932	12,854	7.68	2.37	2.50	6.0	
AREA B2 AVF	32,373,233	27,620,278	28,935,004	27,488,354	24.15	27.63	7.63	0.32	11,895	12,836	6.82	1.12	1.18	0.7	
TOTAL AREA B2	628,992,051	267,473,550	280,205,291	266,195,027	24.20	27.42	7.40	0.30	11,928	12,853	7.59	2.24	2.34	6.7	
LMU 5 AREA A1, A2 AND A3															
AREA A1 and AREA A2	2,497,578,285	848,123,432	888,494,108	844,069,402	24.25	28.40	7.07	0.28	11,954	12,853	7.12	2.81	2.96	21.1	
AREA A3 AVF	13,702,141	8,936,843	9,362,236	8,894,125	23.52	26.91	7.49	0.31	11,575	12,511	4.90	1.46	1.54	0.2	
AREA A2 AVF	46,593,276	40,029,643	41,935,054	39,838,302	24.21	27.84	7.45	0.30	11,917	12,847	6.87	1.11	1.17	1.0	
AREA A1 AVF	8,896,612	8,527,977	8,931,909	8,487,213	24.51	28.53	6.93	0.26	11,956	12,844	7.21	1.00	1.05	0.2	
TOTAL AREA A1 AND A2 COMBINED	2,566,770,315	905,617,895	948,725,307	901,289,042	24.24	28.36	7.09	0.28	11,949	12,849	7.09	2.71	2.85	22.5	
LMU 6 AREA B1 AND B2															
AREA B1 AND B2	1,374,214,993	481,918,577	504,857,901	479,615,066	24.25	27.12	7.07	0.28	11,972	12,868	8.21	2.72	2.87	12.0	
AREA B2 AVF	32,373,233	27,620,278	28,935,004	27,488,354	24.15	27.63	7.63	0.32	11,895	12,836	6.82	1.12	1.18	0.7	
TOTAL AREA B1 AND B2 COMBINED	1,406,588,226	509,538,856	533,792,905	507,103,260	24.24	27.17	7.13	0.28	11,964	12,865	8.07	2.64	2.77	12.7	



T 1 N
T 2 N

T 2 S
T 3 S

T 3 S
T 4 S

T 4 S
T 5 S

LEGEND

- TOPG
- LMU BOUNDARY
- TRACT BOUNDARY



GREAT NORTHERN PROPERTIES
EXHIBIT 3.1
OTTER CREEK PROJECT
LOGICAL MINING UNIT
MAP

There are two possible AVFs³, one lying on the north side and one lying on the west side of this LMU. These potential AVFs contain 40 million tons and 9 million tons of coal, respectively.

Mining operations are primarily oriented north-south and east-west in this LMU.

LMU 3 – Area B1

This LMU is located west of LMUs 1 and 2 and lies within Township 3S, R45E Sections 5, 6, 7, 8, 9, 17 and 18. It covers 2,400 acres and contains 254 million tons of coal at an average effective strip ratio of 3.2:1. Average heating content is 12,012 Btu (air dried basis), and sodium in ash averages 8.7%.

There are no likely AVFs found adjacent to this block.

Mining operations are primarily oriented northwest-southeast along the strike of the coal in this LMU.

LMU 4 – Area B2

This LMU borders on the south of LMU 3 and lies primarily within Township 3S, R45E Sections 15, 16, 17, 18, 20, 21, and 22. It covers 2,300 acres and contains 251 million tons of coal at an average effective strip ratio of 2.4:1. Average heating content is 11,932Btu (air dried basis), and sodium in ash averages 7.7%.

There is one potential AVF lying on the east side of this LMU; this is estimated to contain 29 million tons of coal.

Mining operations are primarily oriented northwest-southeast along the strike of the coal in this LMU.

LMU 5 – Area A1 and A2 Combined

This LMU combines the resources of Area A1 and A2 and is located in Township 4S, R45W and Township 3S, R45E. It covers a total 7,000 acres and contains 751 million tons of coal at an average effective strip ratio of 2.8:1. Average heating content is 11,969Btu (air dried basis), and sodium in ash averages 7.4%.

³ All AVFs are shown separately to recognize that mining could possibly be restricted from this area, should it be classified as an AVF by the State.

There are three potential AVFs: one lying south of Area A1; one lying north of Area A2; and one lying west of Area A2. These potential AVFs contains a total of 51 million tons of coal.

LMU 6 – Area B1 and B2 Combined

This LMU combines the resources of Area B1 and B2 and is located in Township 3S, R45E. It covers a total 4,700 acres and contains 505 million tons of coal at an average effective strip ratio of 2.9:1. Average heating content is 11,972Btu (air dried basis), and sodium in ash averages 8.2%.

There is one possible AVF lying east of Area B2. This potential AVF contains a total of 29 million tons of coal.

COAL QUALITY

Figure A.2 is a cross-section depicting the coal seams in relation to the surface of the land. A summary of coal quality by seam and seam thickness for each LMU is found in Table 3.2, LMU Coal Quality by Seam. This table shows that the quality of the Upper and Lower Knoblock Seams are nearly identical with only minor variations in any of the parameters.

MINING APPROACH

All LMUs are amenable to surface mining using draglines and truck-shovel fleets for overburden removal. These techniques are used at other mines in the region including Absaloka, Decker, Rosebud, and Spring Creek Mines. Large walking draglines working with large (850 hp) push dozers usually remove up to 150 feet of the overburden above the upper coal seam. Overburden greater than 150 feet in thickness and thick interburden are moved using truck-shovel fleets. For thin interburden, large wheel loaders, large push dozers and wheel scrapers can be used effectively. Drilling and blasting is generally required to fragment the overburden and thick interburdens. This eases the digging of this material and increases the equipment productivity.

For each LMU, the dragline was sized according to the accepted mining industry rule of thumb i.e. by dividing the largest annual dragline removal requirements by a dragline productivity factor of 250,000 bank cubic yards (BCY) per cubic yard of dragline bucket capacity. For example: An LMU requiring a maximum annual dragline volume of 30 million BCY would require a dragline having a bucket capacity of 120 cubic yards (CY). Therefore, the smaller LMUs will require 70 to 80 CY draglines while the larger

Table 3.2 Great Northern Properties LMU Coal Quality by Seam

LMU - MINE BLOCK	Seam	Seam Thickness (feet)	IN-SITU COAL QUALITY				
			As Received Moisture (%)	Ash (%)	DRY Sulfur (%)	Btu (btu/lb)	Sodium in the Ash (%)
LMU - 1	UK2	42.08	28.60	6.90	0.26	11,934	6.94
	LK	18.11	28.63	6.88	0.26	11,940	6.83
LMU - 2	UK2	37.08	28.35	7.75	0.28	11,888	5.87
	UK1	4.80	28.39	8.51	0.28	11,795	6.44
	LK	15.06	28.10	8.59	0.39	11,837	5.69
LMU - 3	UK2	44.30	24.30	6.77	0.27	12,012	8.75
	LK	19.33	24.30	6.78	0.27	12,011	8.72
LMU - 4	UK2	46.87	27.38	6.82	0.28	12,002	7.94
	LK	17.63	27.43	8.86	0.32	11,743	6.97
LMU - 5	UK2	43.42	28.39	6.99	0.27	11,960	7.13
	UK1	4.80	28.39	8.51	0.28	11,795	6.44
	LK	18.66	28.34	7.30	0.29	11,934	7.04
LMU - 6	UK2	45.61	28.65	7.18	0.29	12,674	8.73
	LK	18.54	28.82	8.32	0.31	12,605	8.29

LMUs will need 110 to 120 CY draglines. The combined LMUs will require two draglines. For LMUs 1 through 4, the truck-shovel fleet will consist of 25 to 30 CY hydraulic excavators or shovels and 190 to 240 ton trucks.

Coal, when exposed the top surface of the seam, will need to be cleaned using a rubber tired dozer, or grader to scrape away any remaining loose overburden/interburden or oxidized coal. In addition, the upper portions (6 inches to 1 foot) of both the Upper and Lower Knoblock may need to be removed and wasted to help reduce the sulfur content of the shipped product. One mine in the area (Rosebud) currently is utilizing a pavement cutting machine to remove this top layer of coal and process significantly reduces the sulfur content in their shipped coal.

Coal will be loaded by mining shovels, larger front end loaders or hydraulic excavators into large capacity (up to 320 tons) bottom or rear dump trucks and hauled to a coal handling system. The coal will be crushed in multiple stages to a minus 2 inches product, the size required by most thermal coal customers, and placed into a stockpile or loaded into unit trains for shipment to customers, primarily in the Midwest.

When it is necessary to meet the customer's coal specifications, it may be possible to selectively mine the coal to improve the coal quality. The selective mining process removes zones within each seam that are usually higher in sulfur or sodium thereby resulting in a higher quality product.

As an alternate to truck haulage to the coal handling plant, additional studies may indicate that it is more cost-effective to crush the coal at the mining face, using portable hopper/crushers, and then load the crushed product directly onto overland conveyors for transport to a processing plant or unit train loadout facility.

The general mining sequence for each of the LMUs is shown on Figure 3.2, LMU Mine Plan Layout Map. Table 3.3 lists the production rates selected for the LMUs.

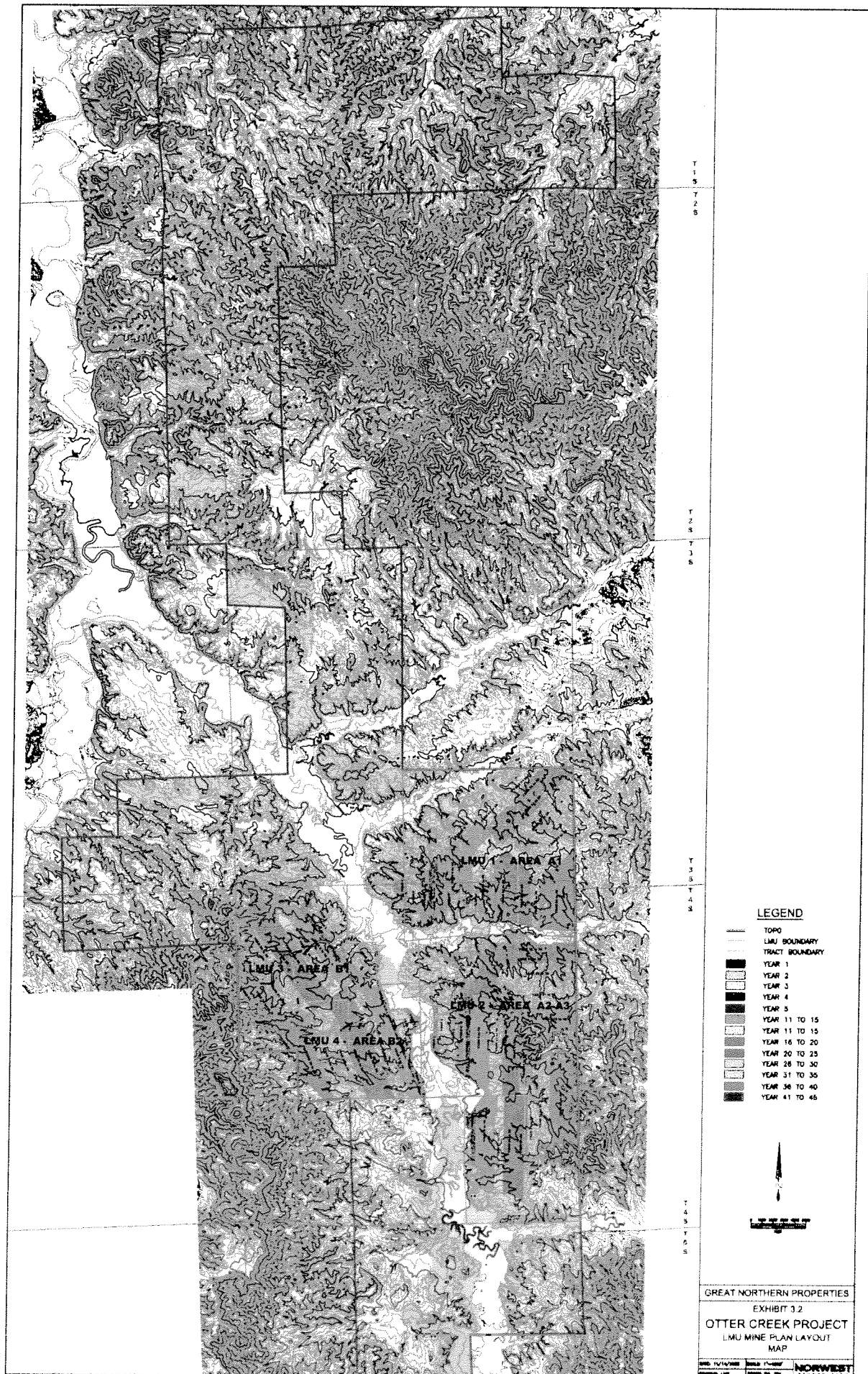


Table 3.3 Production Rate by LMU

LMU	Yearly Production Rate (Tons)
1	8,500,000
2	12,700,000
3	6,000,000
4	6,000,000
5	21,200,000
6	12,000,000

Mining Cost Estimate

Norwest developed a mining cost estimate for each LMU. Mining costs were based on an assessment of the volumes of waste and coal that would be moved over the life of the mine. When using dragline mining systems, as the overburden depths increase, some of the in-situ overburden needs to be moved twice (rehandled) by the dragline. Rehandle can range from 0% to 50% of the in-situ waste material – for the purpose of this study Norwest estimated the dragline rehandle at 25% of the dragline waste volumes (maximum 150 feet of overburden) and truck-shovel rehandle was estimated at 5%. All in-situ waste volumes were increased to reflect the appropriate rehandle percentage by material type. Table 3.4 LMU Mine Plan Volumes show the coal and overburden removal requirement in annual and 5 year increments for each LMU.

Mining costs were calculated based on unit mining costs derived from actual and projected mining costs from mines having similar mining conditions. The estimated final waste volumes and coal tons shown in Table 3.4 were used as inputs to the economic model. Tables 3.5 through 3.10 show the estimated mining costs for the individual LMUs. The average life-of-mine costs for the six LMU range from \$6.69 per ton to \$7.65 per ton.

Mining capital was estimated for each LMU. Table 3.11, Capital Expenditures shows the projected capital expenditures for development, mine infrastructure, coal handling plant, overburden and coal loading trucks and shovels, reclamation equipment and various support equipment including rubber tired dozers, graders, large dozers, water trucks, overburden and coal drills.

Table 3A Great Northern Properties LMI Mine Plan Volumes

Units	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6 to 10	Year 11 to 15	Year 16 to 20	Year 21 to 25	Year 26 to 30	Year 31 to 35	Year 36 to 40	Year 41 to 45	TOTALS
LMI 1 - AREA A1														
Coal Tons	3,480,000	8,500,000	8,500,000	8,500,000	8,500,000	42,500,000	42,500,000	42,500,000	42,500,000	42,500,000	42,500,000	42,400,000	100,000	315,000,000
In-Situ Dragline Volumes	5,760,000	16,500,000	28,400,000	13,300,000	18,900,000	104,000,000	104,000,000	92,200,000	94,300,000	96,300,000	100,100,000	101,800,000	200,000	775,300,000
In-Situ Truck-Shovel Volumes	200,000	600,000	2,200,000	3,100,000	3,100,000	33,700,000	33,700,000	15,500,000	19,500,000	19,500,000	70,000,000	48,600,000	0	256,300,000
Dragline Volumes with Rehandle	7,125,000	20,625,000	25,500,000	22,875,000	23,625,000	130,000,000	130,000,000	115,750,000	117,875,000	122,875,000	125,125,000	127,250,000	250,000	909,125,000
Truck-Shovel Volumes with Rehandle	210,000	630,000	2,310,000	1,260,000	3,255,000	28,245,000	35,385,000	16,275,000	20,775,000	34,500,000	73,500,000	51,020,000	0	269,115,000
Effective Strip Ratio	2.10	2.50	3.77	2.84	3.16	3.72	3.91	3.49	3.26	3.75	4.67	4.30	2.50	3.70
BCY : TON														
LMI 2 - AREA A2, A3														
Coal Tons	5,100,000	12,700,000	12,700,000	12,700,000	12,700,000	63,500,000	63,500,000	63,500,000	63,500,000	63,500,000	63,500,000	61,360,000	200,000	495,500,000
In-Situ Dragline Volumes	5,100,000	17,000,000	27,000,000	24,600,000	25,000,000	130,400,000	131,100,000	111,100,000	142,100,000	144,000,000	143,400,000	139,700,000	300,000	1,059,500,000
In-Situ Truck-Shovel Volumes	400,000	700,000	1,800,000	2,300,000	4,200,000	28,100,000	34,700,000	35,500,000	58,100,000	68,600,000	73,100,000	107,700,000	300,000	409,600,000
Dragline Volumes with Rehandle	6,625,000	22,500,000	27,500,000	30,500,000	31,250,000	163,000,000	166,250,000	163,875,000	177,625,000	181,000,000	179,500,000	174,625,000	375,000	1,334,175,000
Truck-Shovel Volumes with Rehandle	410,000	755,000	1,995,000	3,565,000	8,580,000	39,100,000	40,470,000	41,095,000	73,165,000	96,250,000	162,295,000	133,190,000	210,000	623,320,000
Effective Strip Ratio	1.38	1.81	2.32	2.68	3.14	3.18	3.26	3.54	3.94	4.40	5.38	5.01	2.93	3.90
BCY : TON														
LMI 3 - AREA B1														
Coal Tons	2,400,000	6,000,000	6,000,000	6,000,000	6,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	700,000	271,800,000
In-Situ Dragline Volumes	5,200,000	13,400,000	14,240,000	14,140,000	13,078,000	66,900,000	89,825,000	89,825,000	91,960,000	108,472,000	111,592,000	121,344,000	3,184,000	731,320,000
In-Situ Truck-Shovel Volumes	100,000	300,000	833,000	823,000	928,571	7,576,190	15,742,857	23,080,952	26,223,810	45,919,648	52,204,762	68,436,095	1,885,714	244,147,619
Dragline Volumes with Rehandle	6,500,000	16,750,000	17,600,000	17,675,000	16,285,000	83,605,000	114,560,000	111,285,000	114,560,000	135,490,000	139,490,000	151,680,000	3,980,000	914,150,000
Truck-Shovel Volumes with Rehandle	105,000	315,000	845,000	865,000	975,000	7,555,000	16,530,000	24,235,000	27,640,000	48,215,000	54,815,000	71,840,000	1,980,000	256,355,000
Effective Strip Ratio	2.75	2.84	3.11	3.09	2.88	3.05	3.84	4.52	4.75	6.12	6.48	7.45	8.51	4.94
BCY : TON														
LMI 4 - AREA B2														
Coal Tons	2,400,000	6,000,000	6,000,000	6,000,000	6,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	30,000,000	1,600,000	238,000,000
In-Situ Dragline Volumes	4,500,000	7,300,000	7,400,000	8,700,000	9,000,000	51,900,000	55,300,000	62,200,000	62,200,000	61,800,000	71,200,000	73,700,000	3,600,000	478,000,000
In-Situ Truck-Shovel Volumes	100,000	300,000	400,000	400,000	400,000	3,100,000	7,000,000	13,700,000	11,200,000	13,400,000	25,000,000	43,500,000	5,000,000	126,000,000
Dragline Volumes with Rehandle	5,625,000	9,125,000	9,150,000	10,875,000	11,250,000	64,875,000	69,125,000	77,950,000	77,950,000	77,250,000	89,000,000	92,125,000	4,500,000	998,500,000
Truck-Shovel Volumes with Rehandle	105,000	315,000	420,000	420,000	420,000	3,255,000	7,250,000	14,385,000	11,865,000	14,070,000	27,090,000	45,675,000	5,250,000	130,830,000
Effective Strip Ratio	2.39	1.57	1.61	1.92	1.95	2.27	2.55	3.87	3.99	3.84	3.87	4.59	6.09	3.06
BCY : TON														
LMI 5 - AREA A1, A2 AND A3														
Coal Tons	8,600,000	21,200,000	21,200,000	21,200,000	21,200,000	106,000,000	106,000,000	106,000,000	106,100,000	106,000,000	106,000,000	103,700,000	300,000	833,500,000
In-Situ Dragline Volumes	11,000,000	34,300,000	42,400,000	42,700,000	43,900,000	234,400,000	237,600,000	223,300,000	236,400,000	243,100,000	243,700,000	241,500,000	500,000	1,834,000,000
In-Situ Truck-Shovel Volumes	600,000	1,100,000	2,200,000	2,700,000	4,600,000	30,100,000	36,900,000	37,600,000	40,400,000	62,700,000	75,200,000	111,000,000	200,000	436,200,000
Dragline Volumes with Rehandle	13,750,000	42,875,000	53,000,000	53,375,000	54,875,000	293,000,000	297,000,000	279,125,000	295,500,000	303,875,000	304,625,000	301,875,000	625,000	2,293,500,000
Truck-Shovel Volumes with Rehandle	630,000	1,385,000	4,305,000	4,825,000	11,835,000	67,145,000	75,855,000	77,370,000	93,640,000	134,830,000	235,795,000	183,220,000	210,000	891,245,000
Effective Strip Ratio	1.67	2.09	2.70	2.75	3.15	3.40	3.52	3.36	3.67	4.14	5.10	4.68	2.78	3.82
BCY : TON														
LMI 6 - AREA B1 AND B2 COMBINED														
Coal Tons	4,800,000	12,000,000	12,000,000	12,000,000	12,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	60,000,000	2,300,000	475,100,000
In-Situ Dragline Volumes	9,700,000	20,700,000	21,640,000	22,840,000	22,928,000	118,700,000	134,200,000	151,228,000	154,168,000	170,212,000	182,792,000	195,044,000	6,790,000	1,210,120,000
In-Situ Truck-Shovel Volumes	200,000	600,000	1,223,000	1,423,000	1,328,571	10,676,190	22,742,857	36,780,952	37,623,810	59,319,648	78,004,762	111,938,095	6,885,714	368,747,619
Dragline Volumes with Rehandle	12,125,000	25,875,000	27,950,000	28,590,000	27,535,000	148,380,000	167,850,000	189,035,000	192,710,000	212,565,000	228,490,000	243,805,000	8,480,000	1,512,650,000
Truck-Shovel Volumes with Rehandle	210,000	630,000	1,385,000	1,495,000	1,395,000	11,110,000	23,880,000	38,610,000	39,505,000	62,265,000	81,905,000	117,535,000	7,230,000	387,195,000
Effective Strip Ratio	2.57	2.21	2.36	2.50	2.41	2.66	3.20	3.79	3.87	4.58	5.17	6.02	6.83	4.00
BCY : TON														

Table 3.5 LMU 1 - A2 Mine Cost Model

		Units	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6 to 10	Year 11 to 15	Year 16 to 20	Year 21 to 25	Year 26 to 30	Year 31 to 35	Year 36 to 40	Year 41 +	Total
PRODUCTION	Tons Produced (000s)		3,684	8,947	8,947	8,947	8,947	44,737	44,737	44,737	44,737	44,737	44,737	44,737	211	353,737
	Tons Sold (000s)		3,500	8,500	8,500	8,500	8,500	42,500	42,500	42,500	42,500	42,500	42,500	42,500	200	335,100
	95.0%															
	BCY - DRAGLINE Produced (000s)		7,125	19,000	19,000	19,000	19,000	95,000	95,000	95,000	95,000	95,000	95,000	95,000	375	600,375
	BCY - TRUCKS/HOVEL Produced (000s)		210	420	420	420	420	2,100	2,100	2,100	2,100	2,100	2,100	2,100	210	260,115
	Total Units (BCY + tons)		10,835	27,920	27,920	27,920	27,920	138,440	138,440	138,440	138,440	138,440	138,440	138,440	585	1,373,590
	Strip Ratio (BCY / ROM Tons)		2.10	2.28	2.28	2.28	2.28	2.28	2.28	2.28	2.28	2.28	2.28	2.28	2.28	2.28
	BTU/b (DB)		11,818	11,885	11,885	11,885	11,885	11,885	11,885	11,885	11,885	11,885	11,885	11,885	11,885	11,885
	Sulfur % (DB)		0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
	1.8502MBTU		0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43	0.43
CASH PRODUCTION COSTS	Sodium in Ash%		8.38	8.38	8.38	8.38	8.38	8.38	8.38	8.38	8.38	8.38	8.38	8.38	8.38	8.38
	Controlleable Costs															
	Labor, Materials and Supplies															
	OH Removed Dragline	0.306	2,138	5,700	5,700	5,700	5,700	28,350	28,350	28,350	28,350	28,350	28,350	28,350	111	390,813
	OH Tracks - Shovel	0.406	3,841	10,611	10,611	10,611	10,611	53,055	53,055	53,055	53,055	53,055	53,055	53,055	214	671,444
	Drilling & Explosives	0.220	1,584	4,411	4,411	4,411	4,411	22,055	22,055	22,055	22,055	22,055	22,055	22,055	88	272,792
	Coal Loading - Haulage	0.250	1,818	5,061	5,061	5,061	5,061	25,305	25,305	25,305	25,305	25,305	25,305	25,305	101	308,775
	Other Support Equipment	0.200	1,454	4,011	4,011	4,011	4,011	20,055	20,055	20,055	20,055	20,055	20,055	20,055	80	240,800
	Other Supplies & Services	0.100	727	2,006	2,006	2,006	2,006	10,028	10,028	10,028	10,028	10,028	10,028	10,028	40	120,400
	Coal Handling Plant	0.200	1,454	4,011	4,011	4,011	4,011	20,055	20,055	20,055	20,055	20,055	20,055	20,055	80	240,800
NON-CONTROLLABLE COSTS	Reclamation	0.099	315	765	765	765	765	3,825	3,825	3,825	3,825	3,825	3,825	3,825	15	30,150
	Total Controllable Costs		8,356	21,319	21,319	21,319	21,319	105,585	105,585	105,585	105,585	105,585	105,585	105,585	426	670,200
	\$/SALES TON		2.29	2.48	2.48	2.48	2.48	2.48	2.48	2.48	2.48	2.48	2.48	2.48	2.48	2.48
	NON-CONTROLLABLE COSTS															
	Black Lung Tax	0.306	2,138	5,700	5,700	5,700	5,700	28,350	28,350	28,350	28,350	28,350	28,350	28,350	111	390,813
	Severance Tax	15.0%	2,449	6,811	6,811	6,811	6,811	34,055	34,055	34,055	34,055	34,055	34,055	34,055	136	421,792
	Gross Receipts Tax	5.0%	981	2,706	2,706	2,706	2,706	13,530	13,530	13,530	13,530	13,530	13,530	13,530	54	165,816
	Reclamation Fees	0.350	2,535	7,011	7,011	7,011	7,011	35,055	35,055	35,055	35,055	35,055	35,055	35,055	140	435,840
	Reclamation Bonding (premium)	150	1,080	2,970	2,970	2,970	2,970	14,850	14,850	14,850	14,850	14,850	14,850	14,850	59	182,550
	General Insurance	0.010	975	2,713	2,713	2,713	2,713	13,565	13,565	13,565	13,565	13,565	13,565	13,565	54	166,926
TOTAL CASH COSTS	Corporate Overhead + Joint Facilities	0.060	542	1,396	1,396	1,396	1,396	6,980	6,980	6,980	6,980	6,980	6,980	6,980	28	87,840
	Other	0.050	452	1,261	1,261	1,261	1,261	6,305	6,305	6,305	6,305	6,305	6,305	6,305	25	78,825
	Total Non-Controllable Cash Costs		8,610	21,480	21,480	21,480	21,480	105,940	105,940	105,940	105,940	105,940	105,940	105,940	451	689,025
	\$/SALES TON		2.29	2.49	2.49	2.49	2.49	2.49	2.49	2.49	2.49	2.49	2.49	2.49	2.49	2.49
	\$/SALES TON		18.364	40.599	40.599	40.599	40.599	202.995	202.995	202.995	202.995	202.995	202.995	202.995	812	2,535,770
	TOTAL CASH COSTS															
	Depreciation															
	Total Non-Cash Costs															
	\$/SALES TON		12.205	12.205	12.205	12.205	12.205	61.025	61.025	61.025	61.025	61.025	61.025	61.025	61.025	61.025
	TOTAL MINING COSTS															
	\$/SALES TON		3.49	4.70	4.70	4.70	4.70	2.69	2.69	2.69	2.69	2.69	2.69	2.69	2.69	2.69
CAPITAL	Land Acquisition		28,571	52,004	52,004	52,004	52,004	260,020	260,020	260,020	260,020	260,020	260,020	260,020	1,040	3,355,770
	Permitting - Engineering	3,000														
	Exploration Drilling	2,000														
	Mine Facilities	9,000														
	Coal Handling Plant	28,000														
	Miscellaneous Equipment and supplies	3,000														
	Engines - 70 cyd	44,000														
	Engines - 110 cyd	4,300														
	30 cyd Rock Shovel	13,500														
	30 cyd Rock Shovel	6,400														
TOTAL	210 to 240 Ton Rock Truck	19,200														
	200 to 320 Coal Bottom Dump Trucks	13,400														
	Mobile Equipment	4,200														
	Reclamation Equipment															

Table 3.6 LMU 2 -A2-A3 Mine Cost Model

PRODUCTION		Units	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6 to 10	Year 11 to 15	Year 16 to 20	Year 21 to 25	Year 26 to 30	Year 31 to 35	Year 36 to 40	Year 41 +	Totals	
Tons Produced (000s)	95.0%	tms/yr Recovery	5,368	13,368	13,368	13,368	13,368	66,842	66,842	66,842	66,842	66,842	66,842	66,842	211	524,737	
Tons Sold (000s)		5,100	12,700	12,700	12,700	12,700	63,500	63,500	63,500	63,500	63,500	63,500	63,500	63,500	200	498,500	
BCY - DRAGLINE Produced (000s)		11,750	34,000	43,125	44,125	52,250	236,625	241,500	249,875	248,500	246,500	255,875	246,875	246,875	375	1,911,375	
BCY - TRUCKS/SHOVEL Produced (000s)		420	755	1,995	3,565	8,580	39,100	40,470	61,095	73,165	98,290	162,295	132,190	132,190	210	623,130	
Total Units (BCY + tons)		17,270	47,455	57,820	60,390	73,530	339,225	345,470	374,470	385,265	408,290	481,670	440,365	440,365	785	3,032,005	
Strip Ratio (BCY /ROM Ton)		2.39	2.74	3.55	3.76	4.79	4.34	4.44	4.90	5.06	5.43	6.59	6.18	6.18	2.93	5.08	
BTU/bb (DB)		11,955	11,978	11,971	12,005	11,993	11,992	11,918	11,970	11,970	11,977	11,978	11,974	11,974	11,981	11,973	
Sulfur % (DB)		0.30	0.30	0.30	0.29	0.30	0.30	0.29	0.30	0.28	0.28	0.28	0.28	0.28	0.26	0.29	
LiSO2/MBTU		0.51	0.50	0.50	0.49	0.50	0.49	0.48	0.47	0.47	0.47	0.47	0.47	0.47	0.44	0.48	
Sodium in Ash%		7.60	7.76	7.77	7.89	7.22	7.16	7.20	7.32	7.31	7.34	7.25	7.26	7.25	7.36	7.31	
CASH PRODUCTION COSTS																	
Controllable Costs																	
Materials and Supplies																	
OB Removal Dragline	0.300	\$/BCY	3,525	10,200	12,938	13,238	15,075	70,988	72,450	74,963	74,550	73,950	76,763	74,063	113	573,413	
OB Truck - Shovel	0.400	\$/BCY	168	302	798	1,426	3,432	15,640	16,188	24,438	29,266	39,316	64,918	52,876	84	248,852	
Drilling & Explosives	0.220	\$/UNIT	7,112	13,793	16,529	16,839	19,273	74,585	76,031	78,554	78,141	77,543	80,356	77,655	3,707	620,117	
Coal Loading - Haulage	0.250	\$/TON	1,275	3,175	3,175	3,175	3,175	15,875	15,875	15,875	15,900	15,875	15,875	15,325	50	124,625	
Other Support Equipment	0.200	\$/TON	1,020	2,540	2,540	2,540	2,540	12,700	12,700	12,700	12,720	12,700	12,700	12,600	40	99,700	
Other Supplies & Services	0.100	\$/TON	510	1,270	1,270	1,270	1,270	6,350	6,350	6,350	6,360	6,350	6,350	6,130	20	49,850	
Coal Handling Plant	0.250	\$/TON	1,020	2,540	2,540	2,540	2,540	12,700	12,700	12,700	12,720	12,700	12,700	12,600	40	99,700	
Reclamation	0.09	\$/TON	38	68	180	321	772	3,519	3,642	5,498	6,585	8,846	14,607	11,897	19	55,992	
Total Controllable Costs			14,607	33,888	39,969	41,348	48,077	212,356	215,937	231,078	236,242	247,280	284,506	262,465	4,072	1,872,249	
NON-CONTROLLABLE COSTS																	
Black Lung Tax	0.550	\$/Ton	1,571	3,912	3,912	3,912	3,912	19,558	19,558	19,558	19,558	19,558	19,558	18,880	62	153,538	
Severance Tax	15.0%	% of Revenue	4,297	10,700	10,700	10,700	10,700	53,502	53,502	53,502	53,586	53,502	53,502	51,648	169	420,011	
Gross Receipts Tax	5.0%	% of Revenue	1,432	3,567	3,567	3,567	3,567	17,834	17,834	17,834	17,862	17,834	17,834	17,216	56	140,011	
Reclamation Fees	0.350	\$/Ton	1,785	4,445	4,445	4,445	4,445	22,225	22,225	22,225	22,260	22,225	22,225	21,455	70	174,475	
Reclamation Bonding (premium)	150	\$/000s	150	150	150	150	150	150	150	150	150	150	150	150	150	1,950	
General Insurance	0.010	\$/Unit	173	475	578	604	735	3,392	3,455	3,345	3,853	4,083	4,817	4,404	8	30,320	
Corporate Overhead - Joint Facilities	0.090	\$/Unit	1,554	4,271	5,204	5,435	6,618	30,530	31,092	33,702	34,674	36,746	43,350	39,633	71	277,880	
Other	0.050	\$/Unit	864	2,373	2,394	3,020	3,677	16,961	17,274	18,724	19,263	20,415	24,084	22,018	39	151,600	
Total Non-Controllable Cash Costs			11,826	29,892	31,447	31,832	33,803	164,153	165,089	169,439	171,337	174,512	185,519	175,405	624	1,344,779	
TOTAL CASH COSTS																	
TOTAL CASH COSTS																	
TOTAL CASH COSTS																	
NON-CASH COSTS																	
Depreciation		\$/Unit	18,905	18,905	18,905	18,905	18,905	94,525	94,525	94,525	94,525	94,525	94,525	94,525		598,200	
Total Non-Cash Costs			18,905	18,905	18,905	18,905	18,905	94,525	94,525	94,525	94,525	94,525	94,525	94,525	0	598,200	
TOTAL MINING COSTS																	
TOTAL MINING COSTS																	
TOTAL MINING COSTS																	
CAPITAL																	
CAPITAL																	
CAPITAL																	
Land Acquisition																	
Permitting - Engineering	1,000																
Exploration Drilling	2,800																
Mine Facilities	21,000																
Coal Handling Plant	37,000																
Miscellaneous Equipment and supplies	3,000																
Dragline - 70 cyd	92,000																
Dragline - 110 cyd	8,600																
30 cyd Rock Shovel	27,600																
210 to 240 Ton Rock Trucks	6,400																
20 cyd Coal Excavators	25,600																
290 to 320 Coal Bottom Dump Trucks	15,640																
Mobile Equipment	4,200																
Reclamation Equipment																	

Table 3.7 LMU 3 – B2 Mine Cost Model

		Year 1	Year 2	Year 3	Year 4	Year 5	Year 6 To 10	Year 11 To 15	Year 16 To 20	Year 21 To 25	Year 26 To 30	Year 31 To 35	Year 36 To 40	Year 41 +	Total
PRODUCTION	Tons Produced (000s)	2,526	6,316	6,316	6,316	6,316	31,579	31,579	31,579	31,579	31,579	31,579	31,579	737	249,579
	Tons Sold (000s)	2,400	6,000	6,000	6,000	6,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	700	237,100
	BCY - DRAGLINE Produced (000s)	6,500	16,750	17,250	17,125	15,625	83,875	83,875	89,625	89,625	88,875	86,250	81,500	2,000	670,500
	BCY - TRUCK/SHOVEL Produced (000s)	105	315	865	865	795	16,340	24,235	27,640	27,640	48,215	54,815	71,860	1,980	256,355
	Total Units (BCY + tons)	9,005	23,665	24,115	23,990	22,640	115,080	130,405	142,860	146,640	167,090	171,065	183,360	4,980	1,163,955
	Strip Ratio (BCY ROM/Ton)	2.75	2.84	3.02	3.00	2.77	2.84	3.35	3.76	3.89	4.57	4.70	5.11	5.69	2.69
	BTU/b (DB)	12,030	12,007	12,005	12,010	12,019	12,045	12,058	12,023	12,015	11,984	11,976	11,984	11,988	12,012
	Sulfur % (DB)	0.29	0.26	0.26	0.26	0.26	0.26	0.26	0.27	0.26	0.26	0.26	0.25	0.25	0.27
	LiSO ₂ /MTU	0.49	0.43	0.44	0.44	0.43	0.48	0.46	0.45	0.44	0.43	0.43	0.41	0.42	0.44
	Sodium in Ash%	8.19	7.49	7.44	7.46	7.22	7.90	8.72	8.78	9.04	9.20	9.37	9.20	9.26	8.73
CASH PRODUCTION COSTS															
Controlable Costs	Labor, Materials and Supplies	1,950	5,025	5,175	5,138	4,688	23,138	25,163	26,588	26,700	26,663	25,875	24,450	600	201,150
	Oil Removal Dragline	42	126	346	390	382	3,182	6,612	9,044	11,056	19,286	21,926	28,744	792	102,542
	Drilling & Explosives	2,577	6,464	6,695	6,667	6,361	32,265	35,636	38,177	39,208	43,707	44,582	47,287	1,192	310,977
	Coal Loading - Haulage	600	1,500	1,500	1,500	1,500	7,500	7,500	7,500	7,500	7,500	7,500	7,500	175	59,275
	Other Support Equipment	480	1,200	1,200	1,200	1,200	6,000	6,000	6,000	6,000	6,000	6,000	6,000	140	47,420
	Other Supplies & Services	240	600	600	600	600	3,000	3,000	3,000	3,000	3,000	3,000	3,000	70	23,710
	Cost Handling Plant	480	1,200	1,200	1,200	1,200	6,000	6,000	6,000	6,000	6,000	6,000	6,000	140	47,420
	Reclamation	216	540	540	540	540	2,700	2,700	2,700	2,700	2,700	2,700	2,700	63	21,339
	Total Controlable Costs	6,545	16,655	17,256	17,191	16,479	83,784	92,611	99,858	102,164	114,856	117,583	125,681	3,172	813,833
	\$/SALES TON	2.73	2.78	2.88	2.87	2.75	2.79	3.09	3.33	3.41	3.83	3.92	4.19	4.53	3.43
NON-CONTROLABLE COSTS	Black Lung Tax	719	1,848	1,848	1,848	1,848	9,240	9,240	9,240	9,240	9,240	9,240	9,240	216	73,027
	Severance Tax	2,022	5,055	5,055	5,055	5,055	25,277	25,277	25,277	25,277	25,277	25,277	25,277	590	197,769
	Gross Receipts Tax	674	1,685	1,685	1,685	1,685	8,426	8,426	8,426	8,426	8,426	8,426	8,426	197	66,500
	Reclamation Fees	840	2,100	2,100	2,100	2,100	10,500	10,500	10,500	10,500	10,500	10,500	10,500	245	82,985
	Reclamation Bonding (premium)	150	350	350	350	350	1,750	1,750	1,750	1,750	1,750	1,750	1,750	40	13,500
	General Insurance	90	231	241	240	226	1,131	1,304	1,429	1,466	1,671	1,711	1,834	47	11,640
	Corporate Overhead - Joint Facilities	810	2,076	2,170	2,159	2,034	10,357	11,736	12,857	13,198	15,038	15,396	16,502	421	104,756
	Other	450	1,153	1,206	1,200	1,130	5,754	6,520	7,143	7,332	8,355	8,553	9,168	234	58,198
	Total Non-Controlable Cash Costs	5,776	14,238	14,256	14,437	14,238	70,854	73,153	75,021	75,588	78,656	79,252	81,096	2,099	598,913
	\$/SALES TON	2.41	2.38	2.41	2.41	2.27	2.36	2.44	2.50	2.52	2.62	2.64	2.70	3.00	2.53
TOTAL CASH COSTS															
NON-CASH COSTS	Depreciation	513	516	529	527	512	515	553	583	593	645	656	689	753	596
	Total Non-Cash Costs	10,005	10,005	10,005	10,005	10,005	50,025	50,025	50,025	50,025	50,025	50,025	50,025	30,775	323,200
	\$/SALES TON	4.17	1.67	1.67	1.67	1.67	1.67	1.67	1.67	1.67	1.67	1.67	1.67	0	323,200
	TOTAL MINING COSTS	22,326	40,958	41,716	41,633	40,712	204,663	215,789	224,904	208,527	224,386	227,609	237,552	5,271	1,735,947
	\$/SALES TON	9.30	6.83	6.95	6.94	6.79	6.83	7.19	7.50	6.95	7.48	7.49	7.92	7.53	7.32
CAPITAL	Land Acquisition	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Permitting - Engineering	3,000	-	-	-	-	-	-	-	-	-	-	-	-	-
	Exploration Drilling	2,000	-	-	-	-	-	-	-	-	-	-	-	-	-
	Mine Facilities	9,000	-	-	-	-	-	-	-	-	-	-	-	-	-
	Coal Handling Plant	22,000	-	-	-	-	-	-	-	-	-	-	-	-	-
	Miscellaneous Equipment and supplies	3,000	-	-	-	-	-	-	-	-	-	-	-	-	-
	Dragline - 70 cyl	38,000	-	-	-	-	-	-	-	-	-	-	-	-	-
	Dragline - 110 cyl	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	30 cyl Rock Shovel	3,800	-	-	-	-	-	-	-	-	-	-	-	-	-
	210 to 240 Ton Rock Trucks	12,400	-	-	-	-	-	-	-	-	-	-	-	-	-
200 to 320 Coal Bottom Dump Trucks	Mobile Equipment	3,200	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reclamation Equipment	12,400	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reclamation Equipment	4,200	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reclamation Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reclamation Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reclamation Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reclamation Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reclamation Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reclamation Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Reclamation Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table 3.8 LMI 4 - B2 Mine Cost Model

PRODUCTION	Units	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6 to 10	Year 11 to 15	Year 16 to 20	Year 21 to 25	Year 26 to 30	Year 31 to 35	Year 36 to 40	Year 41 +	Totals
Tons Produced (000s)	tons/yr	2,526	6,316	6,316	6,316	6,316	31,579	31,579	31,579	31,579	31,579	31,579	31,579	1,684	250,526
BCY - DRAGLINE Produced (000s)	Recovery	2,402	6,000	6,000	6,000	6,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	1,500	398,500
BCY - TRUCK/SHOVEL Produced (000s)		5,625	9,125	9,250	10,875	11,250	64,875	69,125	77,750	77,750	77,250	89,000	92,125	4,500	598,500
Total Units (BCY + tons)		8,130	15,440	15,450	17,500	17,670	98,130	106,475	122,125	119,615	121,320	146,000	167,800	11,350	1,049,026
Strip Ratio (BCY / ROM Ton)		2.39	1.57	1.61	1.92	1.95	2.27	2.55	3.07	2.99	3.04	3.87	4.59	6.09	2.39
BTU/b (DB)		12,033	12,042	11,995	11,879	11,926	11,915	11,870	11,855	11,923	11,934	11,951	11,941	11,946	11,932
Sulfur % (DB)		0.29	0.29	0.30	0.32	0.31	0.31	0.31	0.27	0.29	0.29	0.28	0.27	0.29	0.29
Li2SO4/MTB		0.49	0.48	0.50	0.54	0.51	0.51	0.53	0.45	0.49	0.50	0.48	0.47	0.45	0.49
Sodium in Ash%		7.41	7.45	7.44	7.14	7.25	7.83	8.13	8.02	7.58	7.68	7.24	7.52	8.30	7.68
CASH PRODUCTION COSTS															
Controllable Costs															
Labor, Materials and Supplies		1,688	2,738	2,775	3,263	3,375	19,463	20,738	23,325	23,325	23,175	26,700	27,638	1,350	179,550
OB Removal Drilling	\$/BCY	42	126	168	252	168	1,302	1,302	5,754	4,746	5,628	10,836	18,270	2,100	52,132
OB Trucks - Shovel	\$/UNIT	2,344	4,786	4,837	5,241	5,277	28,536	30,372	33,817	33,263	33,638	39,087	43,863	2,868	267,938
Coal Loading - Haulage	\$/TON	600	1,500	1,500	1,500	1,500	7,500	7,500	6,000	7,500	7,500	7,500	7,500	400	59,500
Other Support Equipment	\$/TON	480	1,200	1,200	1,200	1,200	6,000	6,000	6,000	6,000	6,000	6,000	6,000	300	47,600
Other Supplies & Services	\$/TON	240	600	600	600	600	3,000	3,000	3,000	3,000	3,000	3,000	3,000	150	23,800
Coal Handling Plant	\$/TON	480	1,200	1,200	1,200	1,200	6,000	6,000	6,000	6,000	6,000	6,000	6,000	300	47,600
Reclamation	\$/TON	216	540	540	540	540	2,700	2,700	2,700	2,700	2,700	2,700	2,700	144	21,420
Total Controllable Costs	\$/TON	6,090	12,690	12,820	13,795	13,860	74,500	79,249	88,096	86,534	87,641	101,823	114,971	7,662	699,730
NON-CONTROLLABLE COSTS															
Black Lung Tax	\$/Ton	719	1,848	1,848	1,848	1,848	9,240	9,240	9,240	9,240	9,240	9,240	9,240	493	73,104
Severance Tax	% of Revenue	2,022	5,055	5,055	5,055	5,055	25,277	25,277	25,277	25,277	25,277	25,277	25,277	1,348	200,527
Gross Receipts Tax	% of Revenue	674	1,685	1,685	1,685	1,685	8,426	8,426	8,426	8,426	8,426	8,426	8,426	449	66,842
Reclamation Fees	\$/Ton	840	2,100	2,100	2,100	2,100	10,500	10,500	10,500	10,500	10,500	10,500	10,500	560	83,300
Reclamation Bonding (premium)	\$/Ton	150	350	350	350	350	1,500	1,500	1,500	1,500	1,500	1,500	1,500	150	19,500
General Insurance	\$/Unit	81	154	157	175	177	981	1,065	1,221	1,196	1,213	1,461	1,678	114	9,673
Corporate Overhead - Joint Facilities	\$/Unit	732	1,390	1,410	1,575	1,590	8,832	9,583	10,992	10,765	10,919	13,148	15,102	1,022	87,060
Other	\$/Unit	407	772	784	875	884	4,907	5,324	6,107	5,981	6,066	7,305	8,390	568	48,367
Total Non-Controllable Cash Costs	\$/Unit	5,645	13,154	13,189	13,464	13,489	68,312	69,563	71,912	71,534	71,790	75,506	78,762	4,703	571,023
TOTAL CASH COSTS	\$/SALES TON	11,735	25,844	26,009	27,259	27,349	142,812	148,813	160,008	158,068	159,431	177,329	193,733	12,364	1,270,753
NON-CASH COSTS															
Depreciation	\$/Unit	4,89	4,31	4,33	4,54	4,56	4,76	4,96	5,33	5,27	5,31	5,91	6,46	7,73	5,34
Total Non-Cash Costs	\$/Unit	10,255	10,255	10,255	10,255	10,255	51,275	51,275	51,275	51,275	51,275	51,275	51,275	338,200	338,200
TOTAL MINING COSTS	\$/SALES TON	21,990	36,099	36,264	37,514	37,604	194,087	200,088	211,283	209,343	210,706	228,604	245,008	15,668	1,608,953
CAPITAL															
Land Acquisition		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Permitting - Engineering	3,000														
Exploration Drilling	2,000														
Mine Facilities	14,000														
Coal Handling Plant	22,000														
Miscellaneous Equipment and supplies	3,000														
Dragline - 70 cyd	38,000														
Dragline - 110 cyd	-														
30 cyd Rock Shovel	3,000														
210 to 240 Ton Rock Trucks	12,600														
20 cyd Coal Excavators	3,200														
290 to 320 Coal Bottom Dump Trucks	12,800														
Mobile Equipment	12,600														
Reclamation Equipment	4,200														

Table 3.9 LMU 5-A1-A2-A3 Mine Cost Model

	Unit	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6 to 10	Year 11 to 15	Year 16 to 20	Year 21 to 25	Year 26 to 30	Year 31 to 35	Year 36 to 40	Year 41 -	Totals
PRODUCTION															
Tons Produced (000s)		9,053	22,316	22,316	22,316	22,316	111,579	111,579	111,579	111,579	111,579	111,579	109,158	316	877,368
Tons Sold (000s)	95.0%	8,600	21,200	21,200	21,200	21,200	106,000	106,000	106,000	106,000	106,000	106,000	103,700	300	833,500
BCY - DRAGLINE Produced (000s)		18,875	54,625	68,625	67,000	75,875	366,625	372,250	365,125	366,375	369,375	381,000	374,125	625	2,880,500
BCY - TRUCK/SHOVEL Produced (000s)		630	1,385	4,305	4,825	11,835	67,345	73,750	73,750	73,750	73,750	73,750	183,220	210	891,245
Total Units (BCY + tons)		28,105	77,210	94,130	93,025	108,910	539,970	554,105	548,495	566,115	610,205	722,795	661,045	1,135	4,605,245
Strip Ratio (BCY / TON)		2.27	2.64	3.44	3.39	4.14	4.09	4.23	4.17	4.34	4.76	5.82	5.37	2.78	3.58
BTU/b (DB)		11,900	11,940	11,967	11,965	11,949	11,976	11,945	11,946	11,947	11,946	11,986	11,955	11,958	11,958
Sulfur % (DB)		0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.27	0.27	0.25	0.28
Li602/MBTU		0.48	0.47	0.47	0.47	0.47	0.47	0.46	0.45	0.46	0.47	0.46	0.45	0.43	0.46
Sodium in Ash%		7.92	7.94	7.58	8.01	7.61	7.18	6.96	6.97	6.89	6.68	7.34	7.42	7.36	7.14
CASH PRODUCTION COSTS															
Controllable Costs															
Labor: Materials and Supplies															
OB Removed Dragline	0.300	5,663	16,388	20,588	20,100	22,763	109,988	111,675	109,538	109,538	110,813	114,300	112,238	188	864,150
OB Trucks - Shovel	0.400	252	554	1,722	1,930	4,734	26,938	30,342	30,548	37,456	37,456	94,318	73,288	84	356,498
Drilling & Explosives	0.220	8,175	21,896	25,618	25,375	28,870	143,341	146,450	145,216	149,116	158,792	183,562	169,445	319	1,206,175
Coal Loading - Haulage	0.250	2,150	5,300	5,300	5,300	5,300	26,500	26,500	26,500	26,500	26,500	26,500	25,925	75	208,375
Other Support Equipment	0.200	1,720	4,240	4,240	4,240	4,240	21,200	21,200	21,200	21,200	21,200	21,200	20,740	60	166,700
Other Supplies & Services	0.100	860	2,120	2,120	2,120	2,120	10,600	10,600	10,600	10,600	10,600	10,600	10,370	30	83,350
Coal Handling Plant	0.200	1,720	4,240	4,240	4,240	4,240	21,200	21,200	21,200	21,200	21,200	21,200	20,740	60	166,700
Reclamation	0.69	774	1,908	1,908	1,908	1,908	9,540	9,540	9,540	9,540	9,540	9,540	9,333	27	75,013
Total Controllable Costs		21,313	56,645	65,736	65,213	74,174	369,366	377,507	374,142	385,606	412,577	481,220	442,078	843	3,126,963
NON-CONTROLLABLE COSTS															
Black Lung Tax	0.408	2,640	6,530	6,530	6,530	6,530	32,648	32,648	32,648	32,648	32,648	32,648	31,940	92	256,718
Severance Tax	15.0%	7,246	17,862	17,862	17,862	17,862	89,310	89,310	89,310	89,310	89,310	89,310	87,372	253	702,265
Gross Receipts Tax	5.0%	2,415	5,954	5,954	5,954	5,954	29,770	29,770	29,770	29,770	29,770	29,770	29,124	84	234,088
Reclamation Fee	0.350	3,010	7,420	7,420	7,420	7,420	37,100	37,100	37,100	37,100	37,100	37,100	36,395	105	291,725
Reclamation Bonding (premium)	150	150	150	150	150	150	150	150	150	150	150	150	150	150	1,950
General Insurance	0.010	281	772	847	930	1,089	5,400	5,541	5,485	5,661	6,102	7,228	6,610	11	46,052
Corporate Overhead - Joint Facilities	0.090	2,529	6,949	8,472	8,372	9,802	48,597	49,869	49,365	50,550	54,918	65,032	59,494	102	414,472
Other	0.050	1,405	3,861	4,207	4,651	5,446	26,999	27,705	27,425	28,306	30,510	36,140	33,052	57	230,262
Total Non-Controllable Cash Costs		19,686	49,497	52,035	51,869	54,252	269,974	271,094	271,253	274,074	280,509	297,398	284,038	855	2,177,534
TOTAL CASH COSTS		40,999	106,142	117,771	117,082	128,426	639,380	649,602	645,394	659,682	693,086	778,618	726,116	1,697	5,304,497
NON-CASH COSTS															
Depreciation		25,845	25,845	25,845	25,845	25,845	129,225	129,225	129,225	129,225	129,225	129,225	129,225	75,975	820,800
Total Non-Cash Costs		25,845	25,845	25,845	25,845	25,845	129,225	129,225	129,225	129,225	129,225	129,225	129,225	75,975	820,800
TOTAL MINING COSTS		66,844	131,987	143,616	142,927	154,271	768,605	778,827	775,219	735,657	769,061	854,593	802,091	1,697	6,125,297
CAPITAL															
Land Acquisition	-														
Permitting - Engineering	3,000														
Exploration Drilling	2,000														
Mine Facilities	15,000														
Coal Handling Plant	52,000														
Miscellaneous Equipment and supplies	3,000														
Dragline - 70 cyd	138,000														
Dragline - 110 cyd	30,000														
30 cyd Rock Shovel	5,600														
210 to 240 Ton Rock Trucks	27,600														
20 cyd Coal Excavators	9,600														
200 to 320 Coal Bottom Dump Trucks	44,800														
Mobile Equipment	22,560														
Reclamation Equipment	8,400														

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Table 3.10 LMU B B1-B2 Mine Cost Model

PRODUCTION	Units	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6 to 10	Year 11 to 15	Year 16 to 20	Year 21 to 25	Year 26 to 30	Year 31 to 35	Year 36 to 40	Year 41 +	Totals
Tons Produced (000s)		5,053	12,632	12,632	12,632	12,632	63,158	63,158	63,158	63,158	63,158	63,158	63,158	2,421	500,105
Tons Sold (000s)	95.0%	4,800	12,000	12,000	12,000	12,000	60,000	60,000	60,000	60,000	60,000	60,000	60,000	2,300	475,100
BCY - DRAGLINE Produced (000s)		12,125	25,875	26,500	28,000	28,875	142,000	153,000	166,375	166,750	166,125	173,625	173,625	6,500	1,269,000
BCY - TRUCK/SHOVEL Produced (000s)		210	630	1,285	1,495	1,395	11,210	23,880	39,505	62,285	81,905	117,535	117,535	7,230	387,185
Total Units (BCY + tons)		17,135	38,505	39,785	41,495	40,270	213,210	236,880	264,995	266,255	288,410	317,155	351,160	16,030	2,131,285
Strip Ratio (BCY / ROM Ton)		2.57	2.21	2.32	2.46	2.36	2.55	2.95	3.42	3.44	3.81	4.29	4.85	5.97	2.54
BTU/b (DB)		12,031	12,031	12,031	12,031	12,031	12,031	12,031	12,031	12,031	12,031	12,031	12,031	12,031	
Sulfur % (DB)		0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	
LiS02/MBTU		0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	0.49	
Sodium in Ash%		7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	7.80	
CASH PRODUCTION COSTS															
Controllable Costs															
Labor, Materials and Supplies		3,638	7,763	7,950	8,400	8,063	42,600	45,900	49,913	50,025	49,838	52,575	52,088	1,950	380,700
OB Removal Dragline	0.300														
OB Truck - Shovel	0.400														
Drilling & Explosives	0.220														
Coal Loading - Haulage	0.250														
Other Support Equipment	0.200														
Other Supplies & Services	0.100														
Coal Handling Plant	0.200														
Reclamation	0.090														
Total Controllable Costs		12,635	29,345	30,076	30,906	30,339	158,285	171,860	187,954	188,698	202,496	219,406	240,651	10,833	1,513,564
NON-CONTROLLABLE COSTS															
Black Lung Tax	0.308														
Severance Tax	15.0%														
Gross Receipts Tax	5.0%														
Reclamation Fee	0.350														
Reclamation Bonding (premium)	150														
General Insurance	0.010														
Corporate Overhead - Joint Facilities	0.090														
Other	0.050														
Total Non-Controllable Cash Costs		11,271	27,303	27,495	27,751	27,567	139,016	142,566	146,783	146,972	150,296	154,407	159,708	6,652	1,167,986
TOTAL CASH COSTS															
NON-CASH COSTS															
Depreciation		23,906	56,647	57,570	58,737	57,906	297,300	314,426	334,737	335,670	352,792	374,013	400,359	17,485	2,681,550
Total Non-Cash Costs		4,98	4.72	4.80	4.89	4.83	4.96	5.24	5.58	5.59	5.88	6.23	6.67	7.60	5.64
TOTAL MINING COSTS															
CAPITAL															
Land Acquisition		15,633	15,633	15,633	15,633	15,633	78,163	78,163	78,163	78,163	78,163	78,163	78,163	78,163	497,300
Permitting - Engineering	3,000														
Exploration Drilling	2,000														
Mine Facilities	9,000														
Coal Handling Plant	35,000														
Miscellaneous Equipment and supplies	3,000														
Dragline - 70 cyd	76,000														
Dragline - 110 cyd															
30 cyd Rock Shovel	4,300														
210 to 240 Ton Rock Trucks	13,000														
20 cyd Coal Excavators	6,000														
290 to 320 Coal Bottom Dump Trucks	25,600														
Mobile Equipment	19,560														
Reclamation Equipment	4,200														

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Table 3.11 Great Northern Properties Capital Expenditures

INITIAL EQUIPMENT REQUIREMENTS

EQUIPMENT	LMU 1 AREA A1	LMU 2 AREA A2-A3	LMU 3 AREA A1-A2-A3	LMU 4 AREA B1	LMU 5 AREA B2	LMU 6 AREA B1-B2	EQUIPMENT COSTS/UNIT
Dragline - 70 cyd				1	1	2	\$38,000
Dragline - 110 cyd	1	2	3				\$46,000
Coal - Shovel 20 cyd	2	2	3	1	1	2	\$3,200
Rock-Shovel 30 cyd	1	2	2			1	\$4,300
Rock Shovel 20 cyd				1	1		\$3,800
OB Trucks - 210 ton				6	6		\$2,100
OB Trucks - 240 ton	6	12	12			6	\$2,300
Coal Trucks - 320 ton	6	8	14	4	4	8	\$3,200
R.T. Dozers	2	2	3	1	1	2	\$700
Dozers	3	3	4	3	3	4	\$1,800
Water Trucks	2	2	3	2	2	3	\$720
Motor Graders	2	2	3	2	2	3	\$1,400
Coal Handling Plant	1	1	1	1	1	1	Varied
Mine Facilities	1	1	1	1	1	1	Varied
OB-Coal Drills	1	2	3	1	1	2	\$2,300
Rec - Scrapers	2	2	4	2	2	2	\$1,250
Rec - Dozers	1	1	2	1	1	1	\$1,800

INITIAL CAPITAL COSTS

Capital x (000's)	LMU 1 AREA A1	LMU 2 AREA A2-A3	LMU 3 AREA A1-A2-A3	LMU 4 AREA B1	LMU 5 AREA B2	LMU 6 AREA B1-B2
Land Acquisition						
Permitting - Engineering	\$5,000	\$5,000	\$5,000	\$5,000	\$5,000	\$5,000
Exploration Drilling	\$2,000	\$2,000	\$2,000	\$2,000	\$2,000	\$2,000
Mine Facilities	\$9,000	\$21,000	\$15,000	\$9,000	\$14,000	\$9,000
Coal Handling Plant	\$28,000	\$37,000	\$52,000	\$22,000	\$22,000	\$35,000
Miscellaneous Equipment and supplies	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000	\$3,000
Dragline - 70 cyd	\$0	\$0	\$0	\$38,000	\$38,000	\$76,000
Dragline - 110 cyd	\$46,000	\$92,000	\$138,000	\$0	\$0	\$0
30 cyd Rock Shovel	\$4,300	\$8,600	\$8,600	\$0	\$0	\$4,300
30 cyd Rock Shovel	\$0	\$0	\$0	\$3,800	\$3,800	\$0
210 to 240 Ton Rock Trucks	\$13,800	\$27,600	\$27,600	\$12,600	\$12,600	\$13,800
20 cyd Coal Excavators	\$6,400	\$6,400	\$9,600	\$3,200	\$3,200	\$6,400
290 to 320 Coal Bottom Dump Trucks	\$19,200	\$25,600	\$44,800	\$12,800	\$12,800	\$25,600
Mobile Equipment	\$13,340	\$15,640	\$22,560	\$12,640	\$12,640	\$19,560
Reclamation Equipment	\$4,300	\$4,300	\$8,600	\$4,300	\$4,300	\$4,300
TOTAL CAPITAL	\$154,240	\$248,040	\$336,560	\$128,240	\$133,240	\$203,860

MARKETING

ELECTRIC UTILITIES

Montana coal, the Northern PRB, is noted for its higher heating value than most of the Southern PRB mines, its varying sulfur levels and its higher sodium levels. The sodium content of Otter Creek coal ranges from 5.8% to 8.8% and is high in comparison to other coals in the western US. but about the same as other Montana PRB mines. For example: coals from the southern Powder River Basin of Wyoming typically average 1.2% sodium while currently produced coals from Colorado average about 2.5% sodium. Sodium in ash can cause slagging problems in certain types of boilers in electric generating plants. Higher sodium levels generally create greater slagging problems. As a result, most plants avoid burning high sodium coals. Exceptions include the following ten plants which are within the competitive area for Otter Creek currently accept higher sodium coals:

1. St. Clair - Detroit Edison
2. Bell River – Detroit Edison
3. Trenton Channel – Detroit Edison
4. Shiras – Marquette Board of Light & Power
5. Clay-Boswell – Minnesota Power
6. Hoot Lake – Otter Tail Corp.
7. Syl Laskin – Minnesota Power
8. King – Northern States Power
9. Sherburne County – Northern States Power
10. Bay Front (or Bayfront) – Northern States Power

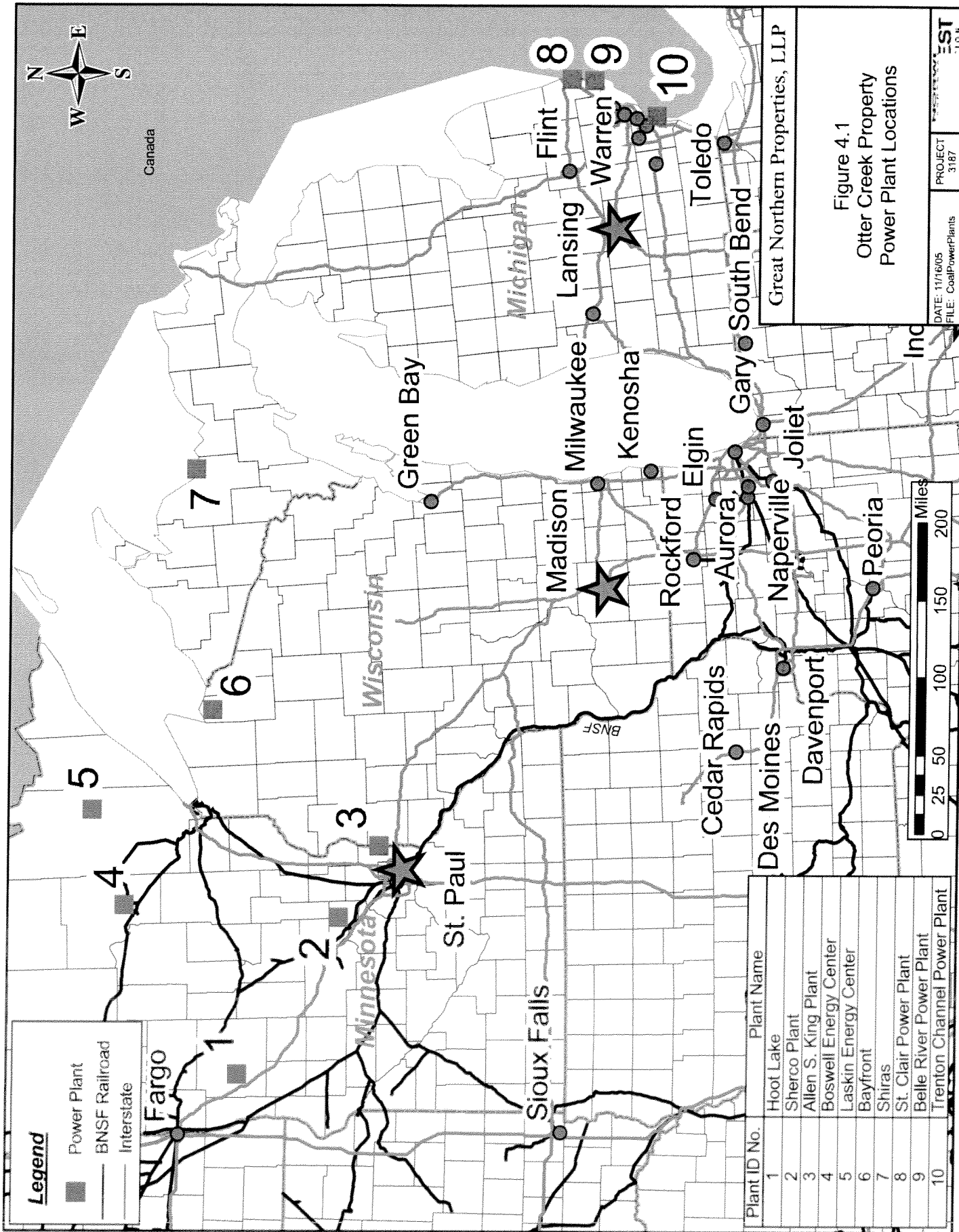
The plants shown in the table would likely constitute the initial target market for Otter Creek coals. The plants are shown on Figure 4.1 numbered from the closest to the most distant plants. Total 2004 volume to these ten plants totaled 20.3 million tons in 2004. Through July of 2005 the annualized total consumption decreased to 16.1 million tons. The difference in consumption rates appears to be due to the intrusion of coal from the Southern PRB. In Table 4.1 below coal quality and delivered prices (discussed below) are also shown.

Table 4.1 Otter Creek Prices of Coal to Potential Customers

2004 FERC data																									2005 FERC through July 2005																								
A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y																									
																												Contract Name	Plant Name	State	Source	Quantity K tons	Cost \$/ton	Subst %	Heat Btu/lb	Cost \$/Btu	U.S. \$	Subst %	Heat Btu/lb	Cost \$/Btu	U.S. \$	Quantity K tons	Contract Name	Subst %	Heat Btu/lb	Cost \$/Btu	U.S. \$	Subst %	Heat Btu/lb
1	Other Tail Corporation	Hoot Lake	MN	Spring Creek	442	9,258	0.38	4.6	143.38	\$ 26.55	600	\$ 0.021	\$ 12.60	\$ 13.95	341	9,247	0.37	4.8	158.42	\$ 29.30	\$ 12.60	\$ 16.70	C-12/07	\$ 10.00																									
2	No States / So MN/Mn: Pwr Agy	Sherburne County	MN	Abasloka	5,851	8,704	0.64	9.2	95.38	\$ 16.64	700	\$ 0.020	\$ 14.00	\$ 2.64	912	8,716	0.63	9.2	115.65	\$ 20.16	\$ 14.00	\$ 6.16	S&C-06/07	\$ 5.85																									
3	Northern States Power	King	MN	Abasloka	351	8,727	0.63	9.07	113.66	\$ 19.84	750	\$ 0.020	\$ 15.00	\$ 4.84	164	8,708	0.58	9.1	115.36	\$ 20.09	\$ 15.00	\$ 5.09	C-12/06	\$ 4.84																									
4	Minnesota Power	Clay Roswell	MN	Decker	777	9,417	0.37	4.5	97.14	\$ 18.30	750	\$ 0.019	\$ 14.25	\$ 4.05	555	9,444	0.40	4.5	105.07	\$ 19.85	\$ 14.25	\$ 5.60	C	\$ 5.32																									
4	Minnesota Power	Clay Roswell	MN	Spring Creek	867	9,273	0.34	4.2	100.12	\$ 18.57	750	\$ 0.019	\$ 14.25	\$ 4.32	693	9,211	0.36	4.5	106.08	\$ 19.54	\$ 14.25	\$ 5.29	C	\$ 5.03																									
5	Minnesota Power	Syl Laskin	MN	Rosebud	2,083	8,773	0.70	8.9	97.02	\$ 17.02	750	\$ 0.019	\$ 14.25	\$ 2.77	1,503	8,693	0.72	9.1	100.89	\$ 17.54	\$ 14.25	\$ 3.29	C	\$ 3.13																									
6	Northern States Power	Bayfront	MN	Decker	408	9,468	0.37	4.4	106.07	\$ 20.09	800	\$ 0.019	\$ 15.20	\$ 4.89	265	9,413	0.37	4.3	117.79	\$ 22.17	\$ 15.20	\$ 6.97	C	\$ 6.63																									
7	Marquette Bd of Light and Power	Shiras	MI	Spring Creek	197	9,321	0.32	4.1	153.39	\$ 29.04	800	\$ 0.019	\$ 19.20	\$ 9.84	34	9,487	0.32	3.9	151.63	\$ 28.77	\$ 19.20	\$ 9.57	S	\$ 9.09																									
8	Detroit Edison	St Clair	MI	Decker	2,552	9,515	0.37	4.1	133.61	\$ 24.91	800	\$ 0.019	\$ 19.70	\$ 5.21	64	9,309	0.31	4.3	142.35	\$ 26.50	\$ 19.70	\$ 6.80	C	\$ 6.46																									
8	Detroit Edison	St Clair	MI	Spring Creek	1,438	9,330	0.33	4.5	146.04	\$ 27.79	800	\$ 0.019	\$ 21.70	\$ -	1,036	9,478	0.38	4.4	125.30	\$ 23.75	\$ 21.70	\$ 2.05	S	\$ 1.95																									
9	Detroit Edison	Belle River	MI	Decker	2,452	9,515	0.37	4.5	146.03	\$ 27.79	800	\$ 0.019	\$ 21.70	\$ 6.09	772	9,295	0.32	4.3	96.41	\$ 17.92	\$ 17.05	\$ 0.88	C-12/06	\$ 0.83																									
9	Detroit Edison	Belle River	MI	Spring Creek	1,401	9,330	0.33	4.1	91.36	\$ 17.05	800	\$ 0.019	\$ 17.05	\$ -	996	9,477	0.38	4.4	125.61	\$ 23.81	\$ 21.70	\$ 2.11	S	\$ 2.00																									
10	Detroit Edison	Trenton Channel	MI	Spring Creek	1,418	10,850	0.68	6.0	135.25	\$ 29.35	800	\$ 0.019	\$ 17.30	\$ 12.05	742	9,296	0.32	4.3	96.80	\$ 18.00	\$ 17.05	\$ 0.95	C-12/05	\$ 0.90																									
	Sub Total				20,312										16,092	annualized total																																	
	Other potential customers:																																																
	Consumers Energy	B C. Cobb		Rosebud	929	9,045	0.50	6.7	128.28	\$ 23.21					464	9,004	0.47	6.8	\$ 128.23																														
	Colstrip	Colstrip		Rosebud	6,378			6.0	135.25	\$ 29.35					3,867	8,495	0.67	9.5																															
	Salt River Project	Coronado	AZ	Spring Creek	71	10,850	0.68	6.0	135.25	\$ 29.35					167	9,327	0.32	4.0	\$ 144.15																														
	TVA	GRT Terminal		Spring Creek	243			7.3	123.96	\$ 21.51					262			9.4	\$ 136.17																														
	Montana-Dakota Utilities	Heskett		Rosebud	79	8,678	0.49	7.3	123.96	\$ 21.51					83	8,678	0.77	9.4	\$ 136.17																														
	Consumers Energy	J.C. Wadlock		Rosebud	239	9,034	0.50	6.7	123.77	\$ 22.36					302	9,008	0.48	6.8	\$ 118.50																														
	RP&L A Western Resources Co	Lawrence	KS	Spring Creek	246	8,979	0.33	6.90	108.75	\$ 19.53					-																																		
	Montana-Dakota Utilities	Lewis & Clark		Spring Creek	15	8,700	0.72	9.0	127.20	\$ 22.13					3	8,700	0.72	9.0	\$ 139.70																														
	Wisconsin Power & Light	Nelson Dewey		Spring Creek	307	9,354	0.32	4.0	112.00	\$ 20.95					240	9,362	0.32	4.1	\$ 127.99																														
	Wisconsin Power & Light	Presque Isle		Spring Creek	466	9,103	0.28	4.4	110.64	\$ 20.14					274	9,059	0.28	4.9	\$ 117.21																														
	Northern Indiana Public Service	Rollie Shafter		Spring Creek	55	9,257	0.32	4.2	148.30	\$ 27.46					39	9,330	0.35	4.1	\$ 167.17																														
	United Power Association	Stanton		Spring Creek	266	9,228	0.49	7.3	100.59	\$ 18.56					442	9,285	0.33	5.4	\$ 96.76																														
	RP&L A Western Resources Co	Tecumseh	KS	Spring Creek	105	8,979	0.33	6.9	108.80	\$ 19.54					-																																		
	Montongahela Power	Willow Island		Spring Creek	8	11,586	1.33	8.0	179.02	\$ 41.48					-																																		
	Sub Total				9,407										10,529																																		
	Total				29,719										26,621																																		
	Total ex Colstrip				23,341										19,992																																		
	11/16/2005 15:03																																																

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The data in this table is derived from FERC data. It is, from our experience, the best data available but not much audited for accuracy of reporting nor input into their database. Columns 'J' and 'T', for instance, show the delivered price per million Btus. When we subtract our best estimate of loadout, rail, and in some cases loadout to barge and barge transportation costs, the resulting FOB mine prices vary widely and are, in some cases, negative. Averaging these resulting prices, as shown at the bottom of columns 'Q' & 'W', produces apparently unrealistic FOB prices. In further work on the mine feasibility, special focus should be directed to these elements.

Note that the column titled Contract/Spot in Table 4.1 indicates whether a power plant is being supplied via contracts or spot sales. We anticipate that the new prices on expiring contracts will be increased by \$4.00 to \$7.00 per ton plus any increased rail or barge costs. The spot market sales in 2005 to Detroit Edison's lakeside plants shows an upturn of about \$5.50 per ton over 2004 spot prices.

The volume of coal shipped from Montana to the high sodium-accepting power plants is only about 20 million tpy. Careful effort developing a solid market strategy will be necessary to determine how best to nudge into this market without destroying whatever price discipline, if any, currently exists.

The second group of power plants in Table 4.1 are (or were) also served by Montana mines neighboring Otter Creek, including Rosebud, Absaloka, Decker, and Spring Creek

All these mines have been operating for many years and are experiencing higher stripping ratios in the range of 3-4:1 at Spring Creek, climbing up to 9:1 and higher at Decker. These higher strip ratios put these mines at a disadvantage with respect to Otter Creek's projected operating costs, as they each must move more waste to uncover the same amount of coal as at Otter Creek. This higher cost, however, will be offset by Otter Creek's higher capital recovery / depreciation costs.

SYNFUEL PLANTS

Another important potential market for GNP coal is synthetic fuels. Very few properties contain such a huge coal reserve and at such an attractive stripping ratio (less than 3:1). Otter Creek could be considered an ideal property for a large scale synfuel plant.

This would probably entail attracting a large energy company with adequate financial capability to construct a mine mouth conversion plant at Otter Creek. Companies like Shell Oil, ConocoPhillips, Chevron-Texaco and ExxonMobil fit this profile. They would possibly be attracted by the large reserve base of Otter Creek.

TRANSPORTATION

At present there are no established transportation links to the Otter Creek property. Barring more rapid than anticipated construction of the Dakota Minnesota & Eastern railway, the product coal would likely get to market by rail or truck/rail.

RAIL

Sized product coal would be loaded at the mine into trains which would travel via a rail spur to the line at Colstrip, located about 38 rail miles distant. From Colstrip the trains would continue on to their final destination, a power plant among those shown in the prior figure and table. This alternative would require the construction of:

- Typical coal crushing, storage and loadout facilities at the mine to accommodate 12,000-ton unit trains
- A 38-mile rail spur from the mine to Colstrip to connect to the mainline.

Normally, the construction cost of the spur would be funded by the BNSF with the cost then rolled into the freight tariff. Alternatively, the construction cost could be funded by the mining company(ies) who should receive a corresponding (slight) tariff reduction to cover the railroad's avoided capital cost. The construction cost of the rail spur to Colstrip is estimated to be about \$78 million⁴.

Working on the assumption that the construction would be funded by the railroad, we estimate the freight rate to be 21 mills per ton/mile for a hypothetical 600 haul to the nearest power plant. The freight cost for the 600 mile journey would cost optimistically about \$12.60/ton.

TRUCK/RAIL

Sized product coal would be loaded at the mine into trucks which would travel about 50 miles on existing highways (including the towns of Ashland and Lame Deer) to the nearest access point to the mainline at Colstrip where the coal would be transferred onto

⁴ Based on the work performed by TransSystems Corporation (included in the "Tongue River Feasibility Report" prepared by Resource Data International, dated October 1997). Norwest escalated the 1997 capital cost estimates by 2.5% per year.

trains for the final leg to the recipient power plant. This alternative is more complex and would require the construction of:

Coal crushing, storage and loadout facilities at the mine to accommodate the loading of highway trucks with capacity of about 40 tons.

Truck unloading, storage and loadout facilities at Colstrip to accommodate the loading of unit trains.

The construction cost of the unloading, storage and loadout facilities at Colstrip is estimated to be between \$5-10 million. Assuming a work schedule of 350 working days per year, 24 hours per day, about 30 trucks per hour would be needed to move the production of 10 million tons per year. This is equivalent to one loaded truck every two minutes.

The budget trucking rate for the 50-mile haul to Colstrip is \$0.16/ton mile⁵. Therefore, the cost of the leg to Colstrip would be about \$6.40/ton. The balance of the 600 mile journey would cost \$11.87/ton for a total of \$18.27/ton delivered to the power plant.

CONCLUSION

Norwest does not believe that trucking the coal to Colstrip is a viable option for the following reasons:

Unacceptable Environmental and Social Impacts

As stated above, a loaded truck would pass through the communities of Ashland and Lame Deer about every two minutes. However, every two minutes an empty truck would also pass through the towns. This means that, on average, a coal truck would pass through the towns every minute of the day and night.

Norwest believes the impacts of this traffic on local schools and other aspects of the communities would be unacceptable and that approvals would not be granted.

⁵ Provided on September 29, 2005 by Mr. Ken Moizer, Sales Director, Savage Industries, a coal transportation company.

Unattractive Economics

The higher road transportation cost (\$5.67/ton) results in a yearly penalty of about \$56.7 million which means that the \$77 million capital cost of the rail spur (plus the \$5-10 million cost of the additional facilities at Colstrip) would be offset in less than two years.

Powder River Basin Coal -- Resource & Cost Study
Campbell, Converse and Sheridan Counties, Wyoming
Big Horn, Powder River, Rosebud and Treasure Counties Montana
Prepared for XCEL Energy

Prepared by John T. Boyd Company (Report 3155.001, September 2011)

Filed under Public Service of Colorado Electric Resource Plan 2011 as Exhibit NO. MWR-1

[http://www.xcelenergy.com/About Us/Rates & Regulations/Resource Plans/PSCo 2011 Electric Resource Plan](http://www.xcelenergy.com/About%20Us/Rates%20&%20Regulations/Resource%20Plans/PSCo%202011%20Electric%20Resource%20Plan)

MSHA ID	Company	Mine	2012 Production (mm tons)(a)	2011 Strip Ratio from Boyd Report	2020 Strip Ratio from Boyd Report
4800977	Arch	Black Thunder	93.40	3.8	4.6
4801337	Cloud Peak	Antelope	32.99	2.9	4.5
4801353	Peabody	NARM	109.07	3.0	4.4
4801215	Arch	Coal Creek	7.48	2.5	2.5
4800732	Alpha	Belle Ayr	24.24	3.5	4.3
4800992	Cloud Peak	Cordero Rojo	38.83	3.6	3.7
4801034	Peabody	Caballo	17.81	3.7	3.9
4800083	Black Hills	Wyodak	4.29	2.5	2.5
4801078	Alpha	Eagle Butte	21.65	2.6	3.3
4800993	Peabody	Rawhide	14.95	1.6	1.9
4801429	WFI/Phillips	Dry Fork	5.87	1.2	1.8
4801200	Kiewit	Buckskin	18.21	2.4	1.7
Weighted Average Wyoming PRB			388.79	3.2	4.0
2400839	Ambre	Decker	2.68	4.5	-
2400910	Westmoreland	Absaloka	2.59	3.7	3.7
2401457	Cloud Peak	Spring Creek	17.08	2.5	3.3
2401747	Westmoreland	Rosebud	7.56	4.4	3.9
Weighted Average Montana PRB			29.92	3.3	3.2
Other Mines in Report					
	Arch Coal	Otter Cr			2.3
	Consol/Chevron*	Youngs Cr (Montana)			4.0
	Peabody	School Cr. (Wyoming)			3.6

(a) 2012 production from MSHA (compiled by Arch Coal)

* Reserve sold to Cloud Peak in 2012

U.S. Domestic and Foreign Coal Distribution by State of Origin

Domestic and foreign distribution of U.S. coal by State of origin, 2011

(thousand short tons)

Coal Origin State and Region	Domestic Distribution	Coal Exports		Total Exports	Total Distribution
		By Coal Mines	By Brokers & Traders*		
Alabama	9,222.6	9,030.7	1,127.4	10,158.1	19,380.7
Alaska	1,015.6	1,203.2	-	1,203.2	2,218.8
Arizona	7,872.5	-	-	-	7,872.5
Arkansas	7.2	-	-	-	7.2
Colorado	22,949.4	1,713.8	1,286.4	3,000.2	25,949.6
Illinois	31,679.5	4,641.9	830.4	5,472.4	37,151.9
Indiana	36,633.9	120.0	522.2	642.2	37,276.1
Kansas	31.1	-	-	-	31.1
Kentucky Total	96,148.9	3,533.7	3,610.7	7,144.4	103,293.3
East	56,548.9	2,328.7	3,186.2	5,514.9	62,063.7
West	39,600.1	1,205.0	424.5	1,629.5	41,229.6
Louisiana	3,854.7	-	-	-	3,854.7
Maryland	2,203.8	171.3	327.8	499.1	2,702.9
Mississippi	2,701.2	-	-	-	2,701.2
Missouri	350.3	-	-	-	350.3
Montana	25,346.4	4,993.6	8,205.0	13,198.7	38,545.0
New Mexico	24,899.6	-	-	-	24,899.6
North Dakota	28,088.5	-	-	-	28,088.5
Ohio	27,038.1	-	-	-	27,038.1
Oklahoma	773.1	-	-	-	773.1
Pennsylvania Total	42,936.0	13,439.8	1,057.4	14,497.2	57,433.2
Anthracite	350.3	165.9	221.2	387.1	737.4
Bituminous	42,585.7	13,273.8	836.2	14,110.1	56,695.8
Tennessee	1,385.7	-	-	-	1,385.7
Texas	46,725.3	-	-	-	46,725.3
Utah	17,957.6	1,080.7	-	1,080.7	19,038.3
Virginia	14,325.5	10,845.4	-	10,845.4	25,170.9
West Virginia Total	96,145.1	28,633.4	6,412.7	35,046.1	131,191.2
Northern	36,490.4	5,646.1	-	5,646.1	42,136.4
Southern	59,654.8	22,987.4	6,412.7	29,400.1	89,054.8
Wyoming	433,294.9	3,002.2	1,468.8	4,471.0	437,765.9
Appalachian Total	249,805.8	64,449.3	12,111.5	76,560.8	326,366.6
Interior Total	162,356.4	5,966.9	1,777.1	7,744.0	170,100.4
Western Total	561,424.4	11,993.5	10,960.2	22,953.8	584,378.2
East of Mississippi River	360,420.5	70,416.2	13,888.6	84,304.8	444,725.3
West of Mississippi River	613,166.1	11,993.5	10,960.2	22,953.8	636,119.9
U.S. Total	973,586.7	82,409.7	24,848.9	107,258.6	1,080,845.2

* The coal exports by brokers/traders are estimated data.

- = No data are reported.

Note: The coal imports are excluded in this report. Total may not equal sum of components because of independent rounding.

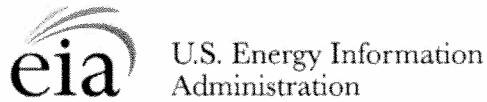
Sources: U.S. Energy Information Administration Form EIA-923, "Power Plant Operations Report," Form EIA-3, "Quarterly Coal Consumption and Quality Report, Manufacturing and Transformation/Processing Coal Plants and Commercial and Institutional Coal Users," Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants," Form EIA-7A, "Coal Production and Preparation Report," and Bureau of the Census, U.S. Department of Commerce, "Monthly Report EM 545."

US Census Foreign Trade Statistics

2012 is through November

Year	District Name	District State	Fuel Code	Transaction Type	Country Name	Fuel Quantity	Unit of Measurement	Number of Transactions
2012	Seattle	WA	Anthracite Coal	Export	Canada	106	Metric Tons	2
2012	Seattle	WA	Anthracite Coal	Import	China	600	Metric Tons	2
2012	Seattle	WA	Bituminous Coal	Import	Canada	20519	Metric Tons	4
2012	Seattle	WA	Coal - generic	Import	Canada	19	Metric Tons	1
2012	Seattle	WA	Coal Based Synfuel	Export	China	131	Metric Tons	1
2012	Seattle	WA	Lignite Coal	Export	Canada	70	Metric Tons	4
2012	Seattle	WA	Lignite Coal	Export	China	537	Metric Tons	9
2012	Seattle	WA	Lignite Coal	Export	Japan	18	Metric Tons	1
2012	Seattle	WA	Lignite Coal	Export	Thailand	539	Metric Tons	14
2012	Seattle	WA	Lignite Coal	Import	Canada	849	Metric Tons	2
2012	Seattle	WA	Liquefied Natural Gas	Export	Canada	3590	Thousand of Cubic Meters	13
2012	Seattle	WA	Subbituminous Coal	Export	Australia	151510	Metric Tons	10
2012	Seattle	WA	Subbituminous Coal	Export	China	313391	Metric Tons	23
2012	Seattle	WA	Subbituminous Coal	Export	South Korea	3344579	Metric Tons	226
2012	Seattle	WA	Subbituminous Coal	Export	Taiwan	91143	Metric Tons	6
2012	Seattle	WA	Waste Coal	Export	Brunei Darussalam	18	Metric Tons	2
2012	Seattle	WA	Waste Coal	Export	Canada	228	Metric Tons	5
2012	Seattle	WA	Waste Coal	Export	Japan	146	Metric Tons	8
2012	Seattle	WA	Waste Coal	Export	Malaysia	11	Metric Tons	1
2012	Seattle	WA	Waste Coal	Export	Singapore	64	Metric Tons	8
2012	Seattle	WA	Waste Coal	Export	South Korea	211	Metric Tons	6
2012	Seattle	WA	Waste Coal	Export	Taiwan	50	Metric Tons	1
2012	Seattle	WA	Waste Coal	Export	Thailand	6	Metric Tons	1
2011	Seattle	WA	Anthracite Coal	Export	Canada	470	Metric Tons	7
2011	Seattle	WA	Anthracite Coal	Import	China	2077	Metric Tons	1
2011	Seattle	WA	Bituminous Coal	Export	Canada	7	Metric Tons	1
2011	Seattle	WA	Bituminous Coal	Import	Canada	43469	Metric Tons	7
2011	Seattle	WA	Coal - generic	Export	South Korea	435649	Metric Tons	29
2011	Seattle	WA	Coal - generic	Import	Canada	39	Metric Tons	2
2011	Seattle	WA	Coal Based Synfuel	Import	China	96	Metric Tons	1
2011	Seattle	WA	Lignite Coal	Export	Canada	1709	Metric Tons	4

2011 Seattle	WA	Lignite Coal	Export	China	80 Metric Tons	2
2011 Seattle	WA	Lignite Coal	Export	India	20 Metric Tons	1
2011 Seattle	WA	Lignite Coal	Export	South Korea	20 Metric Tons	1
2011 Seattle	WA	Lignite Coal	Import	Canada	693 Metric Tons	2
2011 Seattle	WA	Liquefied Natural Gas	Export	Canada	5540 Thousand of Cubic Meters	16
2011 Seattle	WA	Subbituminous Coal	Export	Australia	302278 Metric Tons	20
2011 Seattle	WA	Subbituminous Coal	Export	China	156941 Metric Tons	11
2011 Seattle	WA	Subbituminous Coal	Export	Japan	13535 Metric Tons	1
2011 Seattle	WA	Subbituminous Coal	Export	South Korea	3501534 Metric Tons	238
2011 Seattle	WA	Waste Coal	Export	Canada	147 Metric Tons	5
2011 Seattle	WA	Waste Coal	Export	Japan	107 Metric Tons	6
2011 Seattle	WA	Waste Coal	Export	Malaysia	7 Metric Tons	1
2011 Seattle	WA	Waste Coal	Export	Singapore	49 Metric Tons	6
2011 Seattle	WA	Waste Coal	Export	South Korea	115 Metric Tons	5
2011 Seattle	WA	Waste Coal	Export	Taiwan	15 Metric Tons	1
2011 Seattle	WA	Waste Coal	Export	Thailand	6 Metric Tons	1
2011 Seattle	WA	Waste Coal	Import	Canada	34 Metric Tons	2
2010 Seattle	WA	Bituminous Coal	Export	Canada	41418 Metric Tons	27
2010 Seattle	WA	Bituminous Coal	Import	Canada	82629 Metric Tons	13
2010 Seattle	WA	Coal - generic	Export	Australia	105479 Metric Tons	7
2010 Seattle	WA	Coal - generic	Export	China	723585 Metric Tons	49
2010 Seattle	WA	Coal - generic	Export	South Korea	2302727 Metric Tons	155
2010 Seattle	WA	Coal - generic	Re-Export	Canada	1450 Metric Tons	2
2010 Seattle	WA	Coal Based Synfuel	Import	China	1093 Metric Tons	18
2010 Seattle	WA	Lignite Coal	Export	Canada	1490 Metric Tons	5
2010 Seattle	WA	Lignite Coal	Export	China	597 Metric Tons	8
2010 Seattle	WA	Lignite Coal	Export	South Korea	38 Metric Tons	2
2010 Seattle	WA	Lignite Coal	Import	Canada	495 Metric Tons	1
2010 Seattle	WA	Liquefied Natural Gas	Export	Canada	1641 Thousand of Cubic Meters	7
2010 Seattle	WA	Waste Coal	Export	Brunei Darussalam	26 Metric Tons	3
2010 Seattle	WA	Waste Coal	Export	Canada	302 Metric Tons	7
2010 Seattle	WA	Waste Coal	Export	Japan	90 Metric Tons	4
2010 Seattle	WA	Waste Coal	Export	Malaysia	3 Metric Tons	1
2010 Seattle	WA	Waste Coal	Export	Singapore	28 Metric Tons	4



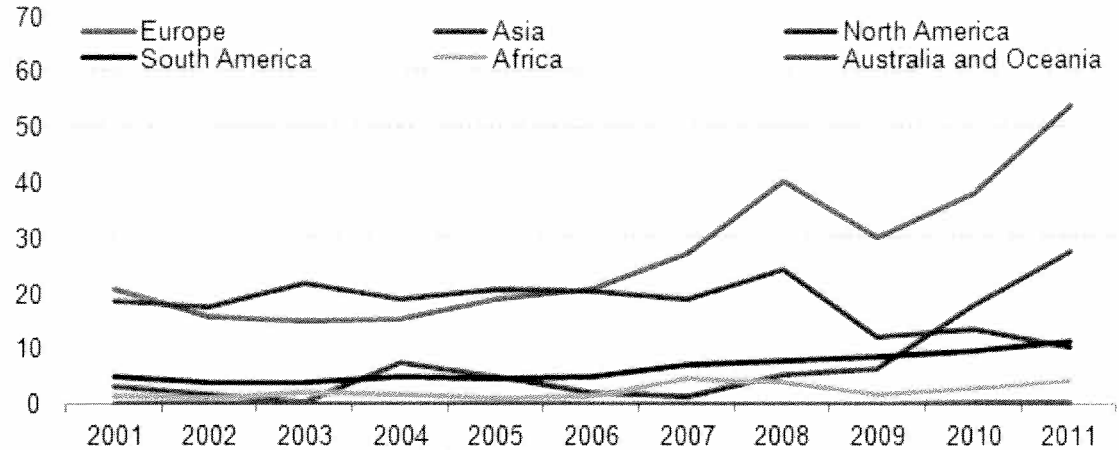
Today in Energy

June 19, 2012

Most U.S. coal exports went to European and Asian markets in 2011

U.S. coal export destinations by region, 2001-2011

million short tons



Source: U.S. Energy Information Administration, based on U.S. Bureau of the Census.

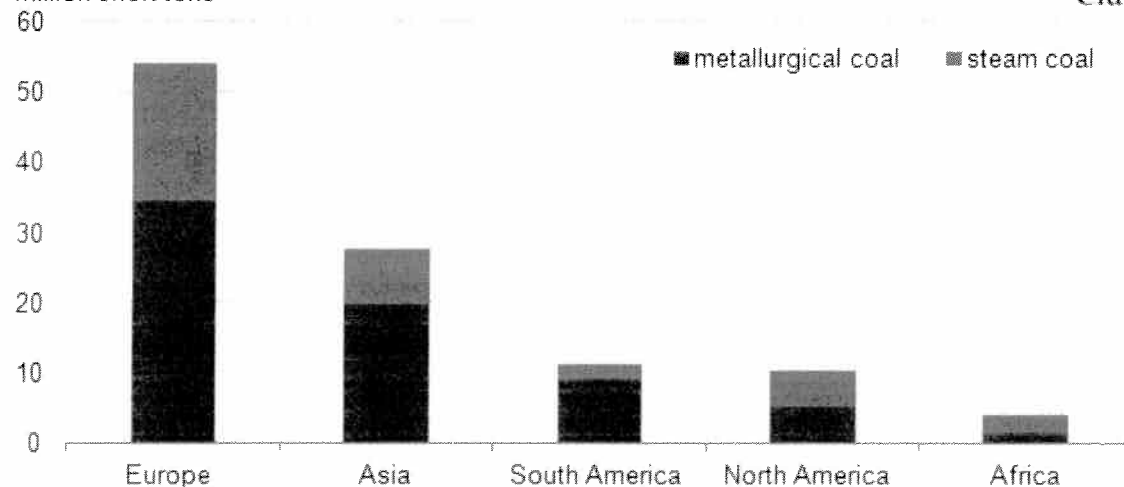
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Coal exports to European and Asian markets represented 76% of total U.S. coal exports in 2011 (see chart above). While European markets have traditionally received a significant portion of U.S. coal exports, the share of coal exported to Asian markets is up since 2009 because of growth in sales to South Korea, China, and India. In 2011, total annual coal exports were up 31% compared to 2010, reaching 107 million short tons, due largely to rising exports to Europe and Asia.

Coal exports come in two forms: metallurgical coal, which can be used for steel production, and steam coal, which can be used for electricity generation. Metallurgical coal dominated U.S. coal exports in 2011 (see chart below); metallurgical coal exports totaled about 70 million short tons compared to about 38 million short tons for steam coal. Demand was high for metallurgical coal in European, Asian, and South American markets.

U.S. coal export destinations by region and by type, 2011

million short tons



Source: U.S. Energy Information Administration, based on U.S. Bureau of the Census.

Note: In addition, the United States exported 333,503 short tons of steam coal (less than 1% of total steam coal exports) to Australia and Oceania collectively in 2011. The United States did not export metallurgical coal to this region.

[Download CSV Data](#)

Here is the coal export summary by region for 2011:

- **Europe.** The Netherlands (11 million short tons) and United Kingdom (7 million short tons) ranked in the top 10 destinations for both U.S. metallurgical coal exports and steam coal exports. Germany (5 million short tons), France (4 million short tons), and Belgium (3 million short tons) ranked among the top 10 U.S. steam coal destinations, while Italy (6 million short tons) and Ukraine (5 million short tons) ranked among the top 10 U.S. metallurgical coal destinations.
- **Asia.** South Korea (10 million short tons) ranked in the top 10 destinations for both U.S. metallurgical coal exports and steam coal exports. In fact, South Korea ranked first for U.S. steam coal destinations. Japan (7 million short tons), China (6 million short tons), and India (5 million short tons) ranked 3rd, 6th, and 9th, respectively, in the top 10 destinations for U.S. metallurgical coal exports.
- **South America.** Brazil (9 million short tons) ranked number 1 for U.S. metallurgical coal destinations, and Chile (2 million short tons) appeared on the list of top 10 U.S. steam coal destinations.
- **North America.** Steam coal exports to Canada and Mexico accounted for 12% of total steam coal exports in 2011. Canada also received 6% of total U.S. metallurgical coal exports.
- **Africa.** Morocco ranked 6th in the top 10 destinations for U.S. steam coal exports with 3 million short tons.

Several major factors contributed to the rise of U.S. coal exports in 2011. In general, coal use abroad continued to grow. U.S. coal exports helped to meet rising Asian demand and provided coal for other emerging markets. Falling domestic coal consumption (down 4.6% in 2011) along with a slight increase in U.S. coal production (0.9%) freed up more coal to export. A series of international coal supply disruptions in 2011 in traditional supply areas such as Australia, Indonesia, and Colombia meant that Asian countries needed to secure coal supplies from alternative markets. Rising spot natural gas prices in Europe, up about 35% in 2011, prompted European electricity generators to use more coal.

AEO2013 Early Release Overview

Executive summary

Projections in the *Annual Energy Outlook 2013* (AEO2013) Reference case focus on the factors that shape U.S. energy markets through 2040, under the assumption that current laws and regulations remain generally unchanged throughout the projection period. This early release focuses on the AEO2013 Reference case, which provides the basis for examination and discussion of energy market trends and serves as a starting point for analysis of potential changes in U.S. energy policies, rules, or regulations or potential technology breakthroughs. Readers are encouraged to review the full range of cases that will be presented when the complete AEO2013 is released in early 2013, exploring key uncertainties in the Reference case. Major highlights in the AEO2013 Reference case include:

Crude oil production, particularly from tight oil plays, rises sharply over the next decade

The advent and continuing improvement of advanced crude oil production technologies continue to lift projected domestic supply. Domestic production of crude oil increases sharply in AEO2013, with annual growth averaging 234 thousand barrels per day (bpd) through 2019, when production reaches 7.5 million bpd (Figure 1). The growth results largely from a significant increase in onshore crude oil production, particularly from shale and other tight formations. After about 2020, production begins declining gradually to 6.1 million bpd in 2040 as producers develop sweet spots first and then move to less productive or less profitable drilling areas.

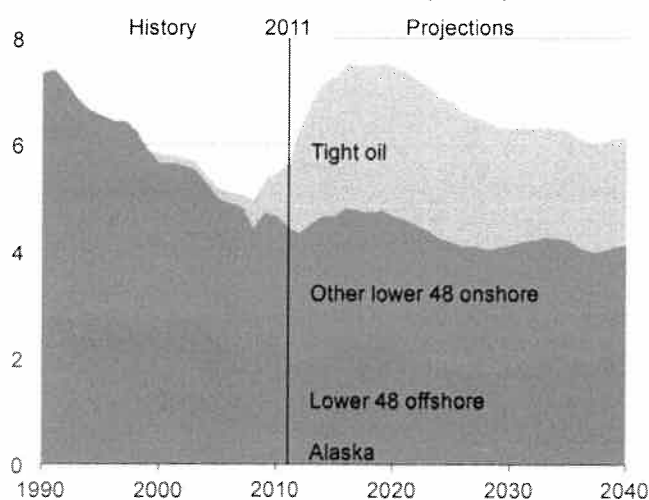
Natural gas production is higher throughout the AEO2013 Reference case projection than it was in AEO2012, with natural gas increasingly serving the industrial and electric power sectors, as well as an expanding export market

Relatively low natural gas prices, facilitated by growing shale gas production, spur increased use in the industrial and electric power sectors, particularly over the next 15 years. Natural gas use (excluding lease and plant fuel) in the industrial sector increases by 16 percent, from 6.8 trillion cubic feet per year in 2011 to 7.8 trillion cubic feet per year in 2025. Although natural gas also continues to capture a growing share of total electricity generation, natural gas consumption by power plants does not increase as sharply as generation because new plants are very efficient. After accounting for 16 percent of total generation in 2000, the natural gas share of generation rose to 24 percent in 2010 and is expected to continue increasing, to 27 percent in 2020 and 30 percent in 2040. In the AEO2013 Reference case, natural gas also reaches other new markets, such as exports, as a fuel for heavy-duty freight transportation (trucking), and as a feedstock for producing diesel and other fuels.

Motor gasoline consumption is lower in AEO2013 relative to the level in AEO2012, reflecting the introduction of more stringent corporate average fuel economy standards; growth in diesel fuel consumption is moderated by increased use of natural gas in heavy-duty vehicles

AEO2013 incorporates the greenhouse gas (GHG) and corporate average fuel economy (CAFE) standards for light-duty vehicles (LDVs)¹ through the 2025 model year, which increases the new vehicle fuel economy from 32.6 miles per gallon (mpg) in 2011 to 47.3 mpg in 2025. The increase in vehicle efficiency reduces gasoline use in the transportation sector by 0.5 million bpd in 2025 and by 1.0 million bpd in 2035 in AEO2013 compared to the *Annual Energy Outlook 2012* (AEO2012) Reference case (Figure 2).

Figure 1. U.S. domestic crude oil production by source, 1990-2040 (million barrels per day)



Furthermore, the improved economics of liquefied natural gas (LNG) for heavy-duty vehicles results in an increase in natural gas use in heavy-duty vehicles that offsets a portion of diesel fuel consumption. The use of petroleum-based diesel fuel is also reduced by the increased use of diesel produced using gas-to-liquids (GTL) technology. Natural gas use in vehicles reaches 1.7 trillion cubic feet (including GTL) by 2040, displacing 0.7 million bpd of other motor fuels.²

The United States exports more natural gas than projected in the AEO2012 Reference case

U.S. dry natural gas production increases throughout the projection period (Figure 3), outpacing domestic consumption by 2020 and spurring net exports of natural gas. Higher volumes of shale gas production in AEO2013 are central to higher total production volumes and an earlier transition to net exports than was projected in the AEO2012 Reference case. U.S. exports of LNG from domestic sources rise to approximately 1.6 trillion cubic feet in 2027, almost double the 0.8 trillion cubic feet projected in AEO2012.

¹U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards: Final Rule," *Federal Register*, Vol. 77, No. 199 (Washington, DC: October 15, 2012), website www.gpo.gov/fdsys/pkg/FR-2012-10-15/pdf/2012-21972.pdf.

²Liquid motor fuels include diesel and liquid fuels from GTL processes. Liquid fuel volumes from GTL for motor vehicle use are estimated based on the ratio of onroad diesel and gasoline to total diesel and gasoline.

Industrial production expands in response to the initial competitive advantage of low natural gas prices

Industrial production grows more rapidly in AEO2013 due to the benefit of strong growth in shale gas production and an extended period of relatively low natural gas prices, which lower the costs of both raw materials and energy, particularly through 2025. Specific industries benefit from the greater availability of natural gas at relatively low prices. For example, industrial production grows by 1.7 percent per year from 2011 to 2025 in the bulk chemicals industries—which also benefit from increased production of natural gas liquids—and by 2.8 percent per year in the primary metals industries, as compared with 1.4 percent and 1.1 percent per year, respectively, in the AEO2012 Reference case. In the long term, growing competition from abroad in these industries limits output growth, as other nations develop and install newer, more energy-efficient facilities. The higher level of production also leads to greater industrial natural gas demand (excluding lease and plant fuel), which grows to more than 8.3 quadrillion Btu in 2035 in AEO2013, compared to 7.2 quadrillion Btu in 2035 in AEO2012. Most of the increase in industrial energy demand is the result of higher output in the manufacturing sector.

Renewable fuel use grows at a much faster rate than fossil fuel use

The share of generation from renewables grows from 13 percent in 2011 to 16 percent in 2040. Electricity generation from solar and, to a lesser extent, wind energy sources grows as recent cost declines make them more economical. However, the AEO2013 projection is less optimistic than AEO2012 about the ability of advanced biofuels to capture a rapidly growing share of the liquid fuels market. As a result, biomass use in AEO2013 totals 4.2 quadrillion Btu in 2035 (compared to 5.4 quadrillion Btu in AEO2012) and 4.9 quadrillion Btu in 2040, up from 2.7 quadrillion Btu in 2011.

With improved efficiency of energy use and a shift away from the most carbon-intensive fuels, U.S. energy-related carbon dioxide (CO₂) emissions remain more than 5 percent below their 2005 level through 2040

Total U.S. energy-related CO₂ emissions do not return to their 2005 level (5,997 million metric tons) by the end of the AEO2013 projection period (Figure 4). Emissions from motor gasoline demand in AEO2013 are lower than in AEO2012 as a result of the adoption of fuel economy standards, biofuel mandates, and shifts in consumer behavior. Emissions from coal use in the generation of electricity are lower as power generation shifts from coal to lower-carbon fuels, including natural gas and renewables.

Introduction

In preparing the AEO2013 Reference case, the U.S. Energy Information Administration (EIA) evaluated a wide range of trends and issues that could have major implications for U.S. energy markets. This overview presents the AEO2013 Reference case and compares it with the AEO2012 Reference case released in June 2012 (see Table 1 on pages 15-16). Because of the uncertainties inherent in any energy market projection, the Reference case results should not be viewed in isolation. Readers are encouraged to review the alternative cases when the complete AEO2013 publication is released, in order to gain perspective on how variations in key assumptions can lead to different outlooks for energy markets.

To provide a basis against which alternative cases and policies can be compared, the AEO2013 Reference case generally assumes that current laws and regulations affecting the energy sector remain unchanged throughout the projection (including the implication that laws that include sunset dates do, in fact, end at the time of those sunset dates). This assumption helps increase the comparability of the Reference case with other analyses, clarifies the relationship of the Reference case to other AEO2013 cases, and enables policy analysis with less uncertainty regarding unstated legal or regulatory assumptions.

Figure 2. Liquids consumption by light-duty vehicles in the United States, AEO2012 and AEO2013 Reference cases, 2010-2040 (million barrels per day)

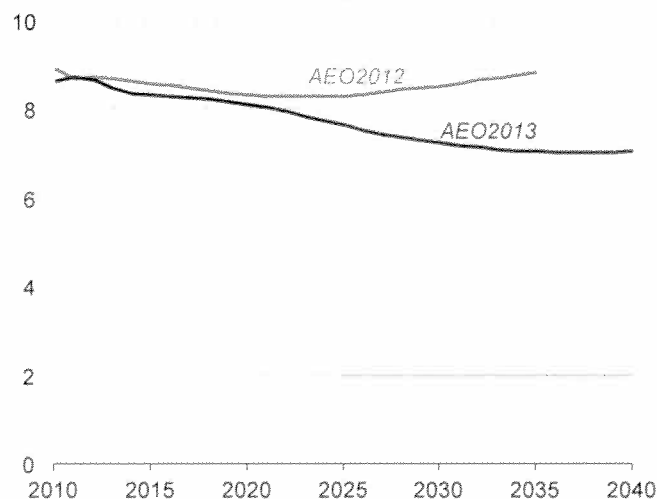
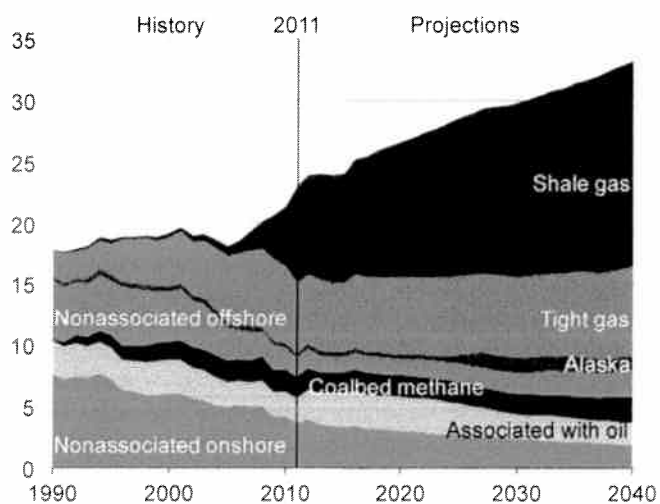


Figure 3. U.S. dry natural gas production by source, 1990-2040 (trillion cubic feet)

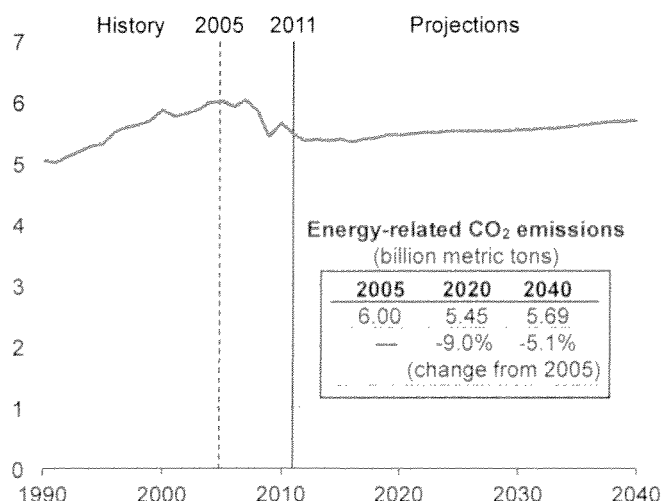


As in past editions, the complete AEO2013 will include additional cases, many of which reflect the impacts of extending a variety of current energy programs beyond their current expiration dates and the permanent retention of a broad set of programs that currently are subject to sunset provisions. In addition to the alternative cases prepared for AEO2013, EIA has examined proposed policies at the request of Congress over the past few years. Reports describing the results of those analyses are available on EIA's website.³

Key updates made for the AEO2013 Reference case include the following:

- Extension of the projection period through 2040, an additional five years beyond AEO2012.
- Adoption of a new Liquid Fuels Market Module (LFMM) in place of the Petroleum Market Module used in earlier AEOs provides for more granular and integrated modeling of petroleum refineries and all other types of current and potential future liquid fuels production technologies. This allows more direct analysis and modeling of the regional supply and demand effects involving crude oil and other feedstocks, current and future processes, and marketing to consumers.
- A shift to the use of Brent spot price as the reference oil price. AEO2013 also presents the average West Texas Intermediate (WTI) spot price of light, low-sulfur crude oil delivered in Cushing, Oklahoma, and includes the U.S. annual average refiners' acquisition cost of imported crude oil, which is more representative of the average cost of all crude oils used by domestic refiners.
- A shift from using regional natural gas wellhead prices to using representative regional natural gas spot prices as the basis of the natural gas supply price. Due to this change, the methodology for estimating the Henry Hub price was revised.
- Updated handling of data on flex-fuel vehicles (FFVs) to better reflect consumer preferences and industry response. FFVs are necessary to meet the Renewable Fuels Standard (RFS), but the phasing out of CAFE credits for their sale and limited demand from consumers reduce their market penetration.
- A revised outlook for industrial production to reflect the impacts of increased shale gas production and lower natural gas prices, which result in faster growth for industrial production and energy consumption. The industries affected include, in particular, bulk chemicals and primary metals.
- Incorporation of a new aluminum process flow model in the industrial sector, which allows for diffusion of technologies through choices made among known commercial and emerging technologies based on relative capital costs and fuel expenditures and provides for a more realistic representation of the evolution of energy consumption than in previous AEOs.
- An enhanced industrial chemical model, in several respects: the baseline liquefied petroleum gas (LPG) feedstock data have been aligned with 2006 survey data; use of an updated propane-pricing mechanism that reflects natural gas price influences in order to allow for price competition between LPG feedstock and petroleum-based (naphtha) feedstock; and specific accounting in the Industrial Demand Model for propylene supplied by the LFMM.
- Updated handling of the U.S. Environmental Protection Agency's (EPA) National Emissions Standards for Hazardous Air Pollutants for industrial boilers and process heaters to address the maximum degree of emissions reduction using maximum achievable control technology. An industrial capital expenditure and fuel price adjustment for coal and residual fuel has been applied to reflect risk perception about the use of those fuels relative to natural gas.

Figure 4. U.S. energy-related CO₂ emissions, 1990-2040 (billion metric tons)



- Augmentation of the construction and mining models in the Industrial Demand Model to better reflect AEO2013 assumptions regarding energy efficiencies in off-road vehicles and buildings, as well as the productivity of coal, oil, and natural gas extraction.
- Adoption of final model year 2017 to 2025 GHG emissions and CAFE standards for LDVs, which increases the projected fuel economy of new LDVs to 47.3 mpg in 2025.
- Updated handling of the representation of purchase decisions for alternative fuels for heavy-duty vehicles. Market factors used to calculate the relative cost of alternative-fuel vehicles, specifically natural gas, now represent first buyer-user behavior and slightly longer breakeven payback periods, significantly increasing the demand for natural gas fuel in heavy trucks.
- Updated modeling of LNG export potential, which includes a rudimentary assessment of pricing of natural gas in international markets.

³See "Congressional Requests," website www.eia.gov/analysis/requests/requests.cfm.

- Updated power generation unit costs that capture recent cost declines for some renewable technologies, which tend to lead to greater use of renewable generation, particularly solar technologies.
- Reinstatement of the Clean Air Interstate Rule (CAIR) after the court's announcement of intent to vacate the Cross-State Air Pollution Rule (CSAPR).
- Modeling of California's Assembly Bill 32, the Global Warming Solutions Act (AB 32), that allows for representation of a cap-and-trade program developed as part of California's GHG reduction goals for 2020. The coordinated regulations include an enforceable GHG cap that will decline over time. AEO2013 reflects all covered sectors, including emissions offsets and allowance allocations.
- Incorporation of the California Low Carbon Fuel Standard, which requires fuel producers and importers who sell motor gasoline or diesel fuel in California to reduce the carbon intensity of those fuels by 10 percent between 2012 and 2020 through the increased sale of alternative low-carbon fuels.

Economic growth

The recovery from the 2008-09 recession continues on a slow path in the AEO2013 Reference case. Consumer confidence surveys are still roughly 25 percent below prerecession levels nearly two years after the official end of the recession in 2009. The slower economic growth in the early years of the projection has implications for the long term, with a lower economic growth rate leading to a slower recovery in employment.

Table 2 compares key long-run economic growth in the AEO2013 and AEO2012 Reference cases to growth rates experienced during the past 30 years. Even though overall GDP growth is slightly lower in the AEO2013 Reference case than the historical period, import growth is slower than export growth, allowing more of the domestic production to satisfy domestic demand. As a result, industrial production growth is higher in AEO2013 than in AEO2012.

Beyond 2013, the economic assumptions underlying the AEO2013 Reference case reflect trend projections that do not include short-term fluctuations. Economic growth projections for 2013 are consistent with those published in EIA's September 2012 *Short-Term Energy Outlook*.

Energy prices

Crude oil

Oil prices are influenced by a number of factors, including some elements that have mainly short-term impacts. Others, such as expectations about future world demand for petroleum and other liquids and production decisions by the Organization of

Table 2. Comparison of key economic growth rates from 2011-2040 to growth from 1980-2010 (percent per year, unless otherwise noted)

	AEO2013	AEO2012 ¹	1980-2010
U.S. Indicators			
Real GDP	2.5	2.6	2.7
Real disposable income	2.3	2.5	2.9
Real consumer spending	2.2	2.3	3.0
Real private investment	4.0	4.2	2.8
Real exports	5.5	5.9	5.3
Real imports	3.8	4.1	6.2
Real government expenditures	0.6	0.5	2.2
Federal funds rate (average rate over period)	3.4	3.6	5.8
Unemployment rate (average rate over period)	5.9	6.4	6.3
Output per hour in nonfarm business	1.9	1.9	2.1
International Indicators			
Real GDP: Major trading countries ²	1.8	1.8	2.4
Real GDP: Other trading countries ³	4.0	4.2	4.5

¹For period from 2011 to 2035.

²Major U.S. trading partners include Australia, Canada, Switzerland, United Kingdom, Japan, Sweden, and the Eurozone.

³Other trading partners include Argentina, Brazil, Chile, China, Colombia, Mexico, Hong Kong, Indonesia, India, Israel, Korea, Malaysia, Philippines, Russia, Saudi Arabia, Singapore, Thailand, Taiwan, and Venezuela.

Source: History: U.S. Bureau of Economic Analysis; Federal Reserve; and U.S. Bureau of Labor Statistics. Projections: AEO2013 National Energy Modeling System, run REF2013.D102312A; and AEO2012 National Energy Modeling System, run REF2012.D020112C.

the Petroleum Exporting Countries (OPEC), affect prices over the longer term. Supply and demand in the world oil market are balanced through responses to price movements, and the underlying supply and demand expectations are both numerous and complex. The key determinants of long-term petroleum and other liquids supply and prices can be summarized in four broad categories: the economics of non-OPEC petroleum liquids supply; OPEC investment and production decisions; the economics of other liquids supply; and world demand for petroleum and other liquids.

For AEO2013, the oil price is represented by spot prices for light, sweet Intercontinental Exchange Brent crude oil instead of WTI crude oil traded on NYMEX. This change was made to better reflect the price refineries pay for imported light, sweet crude oil and takes into account the divergence of WTI prices from those of globally traded benchmark crudes such as Brent. WTI prices have diverged from other benchmark crude prices because of insufficient pipeline capacity to move crude oil to and from Cushing, Oklahoma (the location at which WTI prices are quoted), and the growth of midcontinent and Canadian oil production that has overwhelmed the transportation infrastructure needed to move crude from Cushing to the U.S. Gulf of Mexico.

Among the key assumptions defining the Reference case over the projection period are average economic growth of 1.8 percent per year for major U.S. trading partners; average annual economic growth in other U.S. trading partners of 4.0 percent; and declining liquid fuels consumption per unit of GDP. The OPEC market share of total liquid fuels production remains at approximately 40 to 45 percent over the projection period. Production from non-OPEC countries increases to levels above those in AEO2012. In the AEO2013 Reference case, the Brent spot oil price decreases from \$111 per barrel (in 2011 dollars) in 2011 to \$96 per barrel in 2015. After 2015, the Brent price increases, reaching \$163 per barrel in 2040 (or about \$269 per barrel in nominal dollars) as growing demand leads to the development of more costly resources (Figure 5). A wide range of price scenarios and discussion of the significant uncertainty surrounding future world oil prices will be included in the complete AEO2013 publication released in early 2013.

Liquid products

Real prices (in 2011 dollars) for motor gasoline and diesel delivered to the transportation sector in the AEO2013 Reference case increase from \$3.45 and \$3.58 per gallon, respectively, in 2011 to \$4.32 and \$4.94 per gallon in 2040. Although both prices dip modestly over the early portion of the projection period, increases are steady thereafter. Motor gasoline prices in 2035 are slightly higher in AEO2013 than in AEO2012, but diesel prices are considerably higher in 2035. The diesel share of total domestic liquids production rises, and the gasoline share falls, as a result of incorporation of the model year 2017 to 2025 GHG and CAFE standards for LDVs. Increasing demand for distillate puts pressure on refiners to increase distillate yield and results in higher prices relative to gasoline.

Natural gas

For AEO2013, the Henry Hub spot price is projected using a new methodology. Previously, the Henry Hub prices were based on the average national wellhead price and its historical relationship with the Henry Hub price. Given historical correlations, the projected difference between the Henry Hub price and the national average wellhead price increased as the wellhead price rose over the projection period. The Henry Hub spot prices in the AEO2013 Reference case are based on natural gas prices that balance the supply and demand for Gulf Coast natural gas, which contributes to a lower Henry Hub price projection in AEO2013 than in AEO2012.

With increasing natural gas production, reflecting continued success in tapping the nation's extensive shale gas resource, Henry Hub spot natural gas prices remain below \$4 per million Btu (2011 dollars) through 2018 in the AEO2013 Reference case. The resilience of drilling activity, despite low natural gas prices, is in part a result of high crude oil prices, which significantly improve

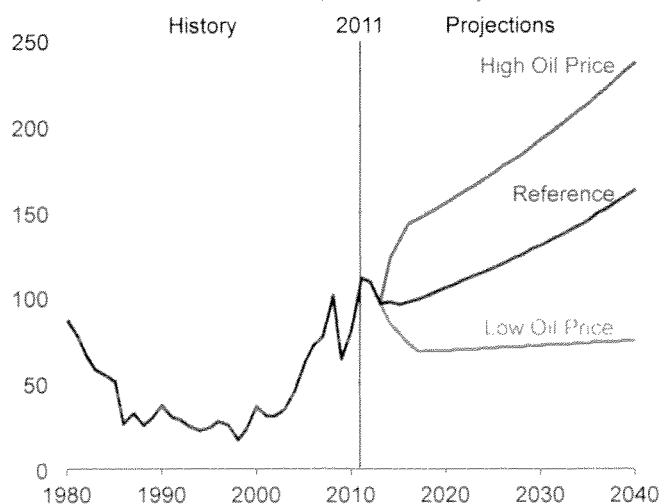
the economics of natural gas plays that have relatively high liquids content (crude oil, lease condensates, and natural gas liquids). Also contributing to growing production volumes are improved drilling efficiencies, which result in a greater number of wells being drilled more quickly, with fewer rigs and higher initial production rates.

After 2018, natural gas prices increase steadily as tight gas and shale gas drilling activity expands to meet growing domestic demand for natural gas and offsets declines in natural gas production from other sources. Natural gas prices rise as lower cost resources are depleted and production gradually shifts to less productive and more expensive resources. Henry Hub spot natural gas prices (in 2011 dollars) reach \$5.40 per million Btu in 2030 and \$7.83 per million Btu in 2040.

Coal

The average minemouth price of coal increases by 1.4 percent per year in the AEO2013 Reference case, from \$2.04

Figure 5. Average annual Brent spot crude oil prices in three cases, 1980–2040 (2011 dollars per barrel)



per million Btu in 2011 to \$3.08 per million Btu in 2040 (2011 dollars). The upward trend of coal prices primarily reflects an expectation that cost savings from technological improvements in coal mining will be outweighed by increases in production costs associated with moving into reserves that are more costly to mine. The upward trend in the minemouth price of coal in the AEO2013 Reference case is similar to the trend in the AEO2012 Reference case, but the average price through the projection period in AEO2013 is generally higher, primarily because of the smaller share of total coal production accounted for by production from lower-cost mines in the West and higher price projections for coking coal.

Electricity

Following the recent rapid decline of natural gas prices, real average delivered electricity prices in the AEO2013 Reference case fall from 9.9 cents per kilowatthour in 2011 to as low as 9.2 cents per kilowatthour in 2015, as natural gas prices remain relatively low. Retail electricity prices are influenced by fuel prices, particularly natural gas prices. However, the relationship between retail electricity prices and natural gas prices is complex, and many factors influence the degree to which and the timeframe over which they are linked. These factors include the share of natural gas generation in a region, the level of costs associated with electricity transmission and distribution systems not directly linked to fuel costs, the mix of competitive versus cost-of-service pricing, and the number of customers who purchase power directly from wholesale power markets. As a result, it can take time for fuel price changes to affect electricity prices, and the impacts will vary from region to region.

In the AEO2013 Reference case, electricity prices are lower throughout the projection than they were in the AEO2012 Reference case. Natural gas prices to electricity generators are significantly lower than those in AEO2012 in the first few years and are between 3 percent and 5 percent lower from 2025 to 2035, while the cost of coal is higher after 2015. As a result, reliance on natural gas-fired generation in the electric power sector increases, with lower operating costs per kilowatthour than in AEO2012. In the long term, however, both natural gas prices and electricity prices rise. Electricity prices in 2035 are 10.1 cents per kilowatthour (2011 dollars) in the AEO2013 Reference case, compared with 10.3 cents per kilowatthour in the AEO2012 Reference case. In AEO2013, the prices continue rising to 10.8 cents per kilowatthour in 2040.

Energy consumption by sector

Transportation

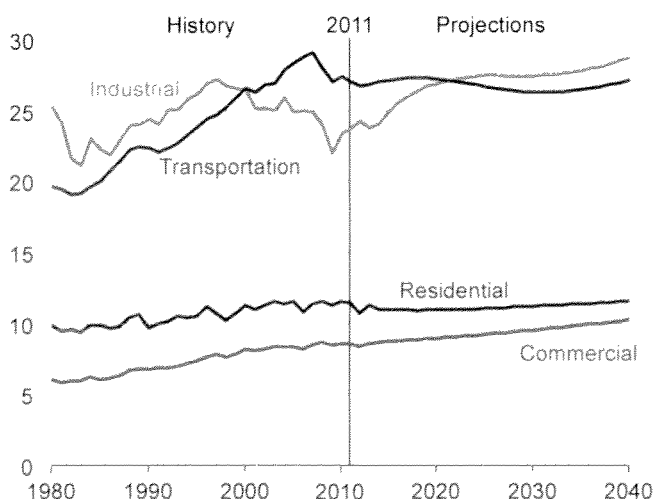
Delivered energy consumption in the transportation sector remains relatively constant at about 27 quadrillion Btu from 2011 to 2040 in the AEO2013 Reference case (Figure 6). Energy consumption by LDVs (including commercial light trucks) declines in the Reference case, from 16.1 quadrillion Btu in 2011 to 14.0 quadrillion Btu in 2025, due to incorporation of the model year 2017 to 2025 GHG and CAFE standards for LDVs. Despite the projected increase in LDV miles traveled, energy consumption for LDVs further decreases after 2025, to 13.0 quadrillion Btu in 2035, as a result of fuel economy improvements achieved through stock turnover as older, less efficient vehicles are replaced by newer, more fuel-efficient vehicles. Beyond 2035, LDV energy demand begins to level off as increases in travel demand begin to exceed fuel economy improvements in the vehicle stock.

Sales of alternative-fuel vehicles in the AEO2013 Reference case are lower than those in AEO2012. The majority of the reduction relative to AEO2012 is reflected in sales of flex-fuel vehicles (FFVs), which in 2035 are about 1.3 million, or less than one-half the 2.9 million FFV sales in the AEO2012 Reference case. Sales of battery-powered electric vehicles also are considerably lower in the AEO2013 Reference case than in AEO2012, with annual sales in 2035 estimated to be about 119,000, or 65 percent lower. Reductions in battery electric vehicles are offset by increased sales of hybrid and plug-in hybrid vehicles, which grow to about

1.3 million vehicles in 2035—about 20 percent higher than in the AEO2012 Reference case. Continued fuel economy improvement in vehicles using other alternative fuels, gasoline, and diesel, combined with growth in the use of hybrid technologies (including micro, mild, full, and plug-in hybrid vehicles), limit the use of electric vehicles over the projection. Although about one-half of new LDV sales in 2040 use diesel, alternative fuels, or hybrid technology, only a small share, less than 1 percent, are all-electric.

Energy demand for heavy trucks increases from 5.2 quadrillion Btu in 2011 to 7.1 quadrillion Btu in 2035 (compared with 6.2 quadrillion Btu in 2035 in the AEO2012 Reference case) and then to 7.6 quadrillion Btu in 2040. Higher industrial output in AEO2013 leads to greater growth in vehicle-miles traveled by freight trucks, which leads to higher energy demand by heavy vehicles in AEO2013 as compared with AEO2012. Factors used to calculate the economic effectiveness of heavy-duty alternative-fuel vehicles have been updated to represent the travel behavior of first-time buyers and

Figure 6. Delivered energy consumption by sector, 1980-2040 (quadrillion Btu)



economic breakeven hurdles that, when coupled with very competitive natural gas prices, significantly increase demand for natural gas fuel in heavy trucks. As a result, natural gas use in heavy-duty vehicles increases to 1.7 trillion cubic feet in 2040, displacing 0.7 million barrels of liquid fuels per day. The AEO2013 Reference case includes the GHG Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles published by the EPA and the National Highway Traffic Safety Administration in September 2011.⁴

Industrial

Approximately one-third of total U.S. delivered energy, 24.0 quadrillion Btu, was consumed in the industrial sector in 2011. In the AEO2013 Reference case, total industrial delivered energy consumption grows by 16 percent, to 27.8 quadrillion Btu in 2035 (0.8 quadrillion Btu higher than in the AEO2012 Reference case) and 28.7 quadrillion Btu in 2040. The rate of growth in total industrial energy consumption is greater from 2011 to 2025 than after 2025 in AEO2013, as industry responds to the lower natural gas prices resulting from the expansion of shale gas production in the near term. After 2025, increased international competition and rising natural gas prices as a result of more modest growth in shale gas production lead to slower growth in industrial energy consumption. The industry that consumes the most energy is bulk chemicals, where energy consumption grows from 5.7 quadrillion Btu in 2011 to 6.6 quadrillion Btu in 2024, before declining to 6.0 quadrillion Btu in 2035 and 5.8 quadrillion Btu in 2040.

The energy-intensive industries initially exhibit strong growth in shipments and energy consumption, but most of the growth in shipments and energy consumption occurs before 2025. In 2011, the energy-intensive industries constitute 27 percent of shipments and 63 percent of industrial energy consumption. In 2040, the energy-intensive industry share of shipments falls to 20 percent, and their share of energy consumption falls to 56 percent. Shipments decline noticeably after 2025 for the aluminum, bulk chemicals, and iron and steel industries, because those industries are more affected by international competition than others. Energy use in the energy-intensive industries increases by 0.9 percent per year from 2011 to 2025 and then falls by 0.2 percent per year from 2025 to 2035.

Non-energy-intensive industries show a different pattern of shipment growth and energy consumption, in part because they are not affected as much as the energy-intensive industries by international competition and energy prices. Non-energy-intensive industry shipments and energy consumption grow throughout the period from 2011 to 2035 in the AEO2013 Reference case, with shipments increasing by 51 percent from 2011 to 2025 and 22 percent from 2025 to 2035, and energy consumption growing at an annual rate of 1.2 percent from 2011 to 2035 (plastics is the only non-energy-intensive industry that shows a decline in energy use). However, the rate of growth in their energy consumption from 2011 to 2025 is roughly twice as high as the rate after 2025, because growth in shipments is slower after 2025. In 2035, the non-energy-intensive industries constitute 53 percent of total industrial shipments and 41 percent of industrial energy consumption.

Two new environmental policies that affect parts of the industrial sector are incorporated in the AEO2013 Reference case. California's AB 32 is a comprehensive law limiting the state's GHG emissions, including those from stationary sources; and the extension of the National Emissions Standards for Hazardous Air Pollutants to industrial boilers and process heaters addresses the maximum degree of emission reduction possible using the maximum achievable control technology (Boiler MACT). Although both AB 32 and the Boiler MACT policies have minimal effects on industrial energy consumption, AB 32 results in a relatively low GHG allowance price, as is also shown in California's own analyses.⁵

Residential

Residential delivered energy consumption remains roughly constant in the AEO2013 Reference case from 2011 to 2040, reflecting consumption levels lower than those in AEO2012. Delivered electricity consumption is 5.7 quadrillion Btu and natural gas consumption is 4.3 quadrillion Btu in 2035 in the AEO2013 Reference case, compared with 5.9 quadrillion Btu and 4.8 quadrillion Btu, respectively, in the AEO2012 Reference case. The lower consumption levels in the AEO2013 Reference case are explained in part by a change in the handling of data on heating and cooling degree days in the projection. The AEO2013 Reference case uses a 30-year trend of historical data as the basis for degree days in both the residential and commercial sectors. Previously, average data for the most recent historical decade were used to represent degree days for the projection period without reflecting any trend over time, which tended to underestimate cooling demand and overestimate heating demand. The change, in combination with updated population projections, results in 6 percent fewer population-weighted heating degree days and 12 percent more population-weighted cooling degree days in 2035, which reduces energy consumption for space heating and increases energy consumption for space cooling. Since more energy is consumed for heating than cooling, this results in a net reduction of delivered energy in AEO2013 when compared with AEO2012.

The updated technology and cost parameters for residential lighting lead to lower electricity consumption. The first round of standards in the Energy Independence and Security Act of 2007 (EISA) are implemented in years 2012 through 2014, with 2014 lighting consumption about 18 percent below its 2011 level. EISA also established a second-tier standard in 2020. In the AEO2012

⁴U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles; Final Rule," *Federal Register*, Vol. 76, No. 179 (September 15, 2011), pp. 57106-57513, website www.epa.gov/ghgs/ghgs.html, FR 2011-09-15; EISA 2007, 101 Stat. 1331, 1332.

⁵See California Environmental Protection Agency, Air Resources Board, "Allowance Price Containment Reserve Analysis," website www.arb.ca.gov/permit/allowance/pricecontainment/pricecontainment.htm.

Reference case, the standard was assumed to be met with improved, halogen-type incandescent technology; but in AEO2013, halogen-type incandescent bulbs are not available in 2020 and beyond, and households adopt more efficient technologies, such as compact fluorescent and light-emitting diode bulbs.

Commercial

Commercial sector energy consumption grows from 8.6 quadrillion Btu in 2011 to 10.2 quadrillion Btu in 2040 in the AEO2013 Reference case, slower than in the AEO2012 Reference case, despite similar growth in square footage in both cases. Growth in commercial electricity consumption averages 0.8 percent per year from 2011 to 2040 in AEO2013, lower than the 1.0-percent average annual growth in commercial floorspace. Changing trends for personal computer adoption, increasing data center efficiency, and slower-than-expected adoption of new data centers as a result of the recent recession all lead to lower electricity consumption in the AEO2013 Reference case than in AEO2012. In addition, decreasing costs for solid-state lighting technologies contribute to an increase in shipments throughout the commercial sector. Distributed generation and combined heat-and-power systems generate 63 billion kilowatthours of electricity in 2035, 47 percent more than in the AEO2012 Reference case. Decreasing technology costs and rapidly increasing capacity in the near term, especially in existing construction, account for higher levels of electricity generation in the commercial sector in the AEO2013 Reference case. Growth of natural gas consumption in the commercial sector continues to average roughly 0.4 percent annually in the AEO2013 Reference case, similar to the rate in the AEO2012 Reference case.

Energy consumption by primary fuel

Total primary energy consumption grows by 7 percent in the AEO2013 Reference case, from 98 quadrillion Btu in 2011 to 104 quadrillion Btu in 2035—2.5 quadrillion Btu less than in AEO2012—and continues to grow at a rate of 0.6 percent per year, reaching about 108 quadrillion Btu in 2040 (Figure 7). The fossil fuel share of energy consumption falls from 82 percent in 2011 to 78 percent in 2040, as consumption of petroleum-based liquid fuels falls, largely as a result of the incorporation of new fuel efficiency standards for LDVs.

While total liquid fuels consumption falls, consumption of domestically produced biofuels increases significantly, from 1.3 quadrillion Btu in 2011 to 2.1 quadrillion Btu in 2040, and its share of total U.S. liquid fuels consumption grows from 3.5 percent in 2011 to 5.8 percent in 2040. The increases are much smaller than those in AEO2012, however, as a result of diminished FFV penetration, a smaller motor gasoline pool for blending ethanol, and reduced production of cellulosic biofuels, which to date has been well under the targets set by the EISA. (EPA issued waivers that substantially reduced the cellulosic biofuels obligation under the RFS for 2010, 2011, and 2012.) In addition, the production tax credit for cellulosic biofuels is scheduled to expire at the end of 2012.

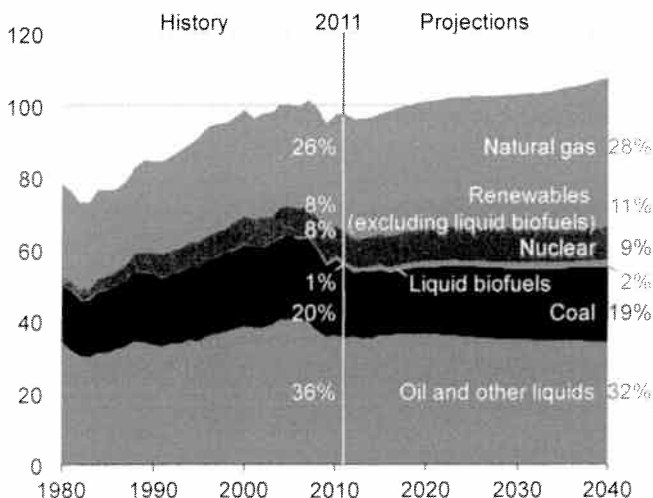
Total U.S. consumption of liquid fuels, including both petroleum-based fuels and biofuels, which was 37.0 quadrillion Btu (18.9 million bpd) in 2011, increases to 37.6 quadrillion Btu (19.8 million bpd) in 2019 in the AEO2013 Reference case, then declines to 35.8 quadrillion Btu (18.9 million bpd) in 2035 before rising to 36.1 quadrillion Btu (about 18.9 million bpd) in 2040. Biofuel consumption increases over most of the projection period. The transportation sector dominates demand for liquid fuels, although its share (as measured by energy content) declines modestly, from 71 percent of total liquids consumption in 2011 to 70 percent in 2040.

In the AEO2013 Reference case, natural gas consumption rises from 24.4 trillion cubic feet in 2011 to 28.7 trillion cubic feet in 2035 (about 2.1 trillion cubic feet higher than in the AEO2012 Reference case) and continues to grow to 29.5 trillion cubic feet in 2040.

The largest share of the growth is for electricity generation. Demand for natural gas in the electric power sector increases from 7.6 trillion cubic feet in 2011 to approximately 9.5 trillion cubic feet in 2040, with a portion of the growth attributable to the retirement of 49 gigawatts of coal-fired capacity by 2022. Natural gas consumption in the industrial sector is also higher in AEO2013 than was projected in AEO2012, due to the rejuvenation of the industrial sector as it benefits from surging shale gas production that is accompanied by slow price growth, particularly from 2011 through 2019, when the price of natural gas remains below 2010 levels. Some industries, such as bulk chemicals, are more strongly affected than others. In the residential sector, natural gas consumption declines throughout the projection period. Because natural gas is used in the residential sector directly for heating but not for cooling, residential natural gas consumption is affected by the 6-percent reduction in heating degree days described above.

Total coal consumption—including the portion of coal-to-liquids (CTL) consumed as liquids—increases from 19.7 quadrillion Btu (999 million short tons) in 2011 to 20.5

Figure 7. U.S. primary energy consumption by fuel, 1980-2040 (quadrillion Btu per year)



quadrillion Btu (1,071 million short tons) in 2040 in the AEO2013 Reference case. Coal consumption, mostly for electric power generation, falls off through 2016. After 2016, coal-fired electricity generation increases slowly as the remaining coal-fired capacity is used more intensively, but little capacity is added. Coal consumption in the electric power sector in 2035 in the AEO2013 Reference case is about 0.6 quadrillion Btu (23 million short tons) lower than projected in the AEO2012 Reference case. The startup of the first CTL plants is delayed to 2023 in the AEO2013 Reference case, with penetration of the technology far more modest than in AEO2012.

Total consumption of marketed renewable fuels grows by 1.6 percent per year in the AEO2013 Reference case. Growth in consumption of renewable fuels results mainly from the implementation of the federal RFS for transportation fuels and state renewable portfolio standard (RPS) programs for electricity generation. Marketed renewable energy includes wood, municipal waste, biomass, and hydroelectricity in the end-use sectors; hydroelectricity, geothermal, municipal solid waste, biomass, solar, and wind for generation in the electric power sector; and ethanol for gasoline blending and biomass-based diesel in the transportation sector, of which 2.2 quadrillion Btu is included with liquid fuel consumption in 2040. Excluding hydroelectricity, renewable energy consumption in the electric power sector grows from 1.6 quadrillion Btu in 2011 to 4.5 quadrillion Btu in 2040, with biomass accounting for 24 percent of the growth and wind 44 percent. Generation of electricity from solar photovoltaic (PV) energy exhibits the fastest growth. Starting from a small base, PV accounts for 17 percent of total electricity generated from renewable energy sources, excluding hydropower, in 2040.

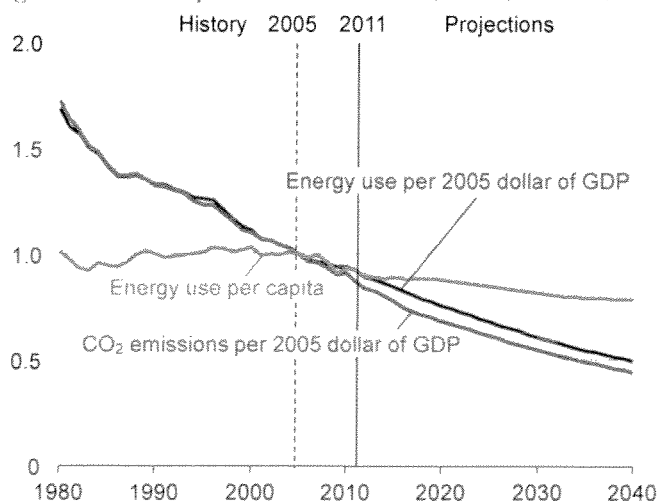
Energy intensity

Population is a key determinant of energy consumption through its influence on demand for travel, housing, consumer goods, and services. U.S. energy use per capita was fairly constant from 1990 to 2007, but it began to fall after 2007. In the AEO2013 Reference case, energy use per capita continues to decline due to the impacts of improving energy efficiency (e.g., new appliance and CAFE standards) and changes in the ways energy is used in the U.S. economy. Total U.S. population increases by 29 percent from 2011 to 2040, but energy use grows by only 10 percent, with energy use per capita declining by 15 percent from 2011 to 2040 (Figure 8).

From 1990 to 2011, energy use per dollar of GDP declined on average by 1.7 percent per year, in large part because of shifts within the economy from manufactured goods to the service sectors, which use relatively less energy per dollar of GDP. The dollar-value increase in the service sectors (in constant dollar terms) was 16 times the corresponding increase for the industrial sector over the same period. As a result, the share of total shipments accounted for by the industrial sector fell from 30 percent in 1991 to 22 percent in 2011. In the AEO2013 Reference case, the industrial share of total shipments reverses the earlier trend, largely due to the benefits of increased domestic production of natural gas, and increases to more than 23 percent in 2016. After 2016, however, the share resumes its decline, falling to less than 22 percent in 2040. Energy use per 2005 dollar of GDP declines by 46 percent from 2011 to 2040 in AEO2013 as the result of a continued shift from manufacturing to services (and, even within manufacturing, to less energy-intensive manufacturing industries), rising energy prices, and the adoption of policies that promote energy efficiency.

CO₂ emissions per 2005 dollar of GDP have historically tracked closely with energy use per dollar of GDP. In the AEO2013 Reference case, however, as lower-carbon fuels account for a larger share of total energy use, CO₂ emissions per 2005 dollar of GDP decline more rapidly than energy use per 2005 dollar of GDP, falling by 56 percent from 2005 to 2040, at an annual rate of 2.3 percent per year.

Figure 8. Energy use per capita and per dollar of gross domestic product and emissions per dollar of gross domestic product, 1980-2040 (index, 2005=1)



Energy production and imports

Net imports of energy decline both in absolute terms and as a share of total U.S. energy consumption in the AEO2013 Reference case (Figure 9). The decline in energy imports reflects increased domestic petroleum and natural gas production, increased use of biofuels (much of which are produced domestically), and demand reductions resulting from rising energy prices and the adoption of new efficiency standards for vehicles. The net import share of total U.S. energy consumption is 9 percent in 2040, compared with 19 percent in 2011 (the share was 30 percent in 2005).

Liquids

U.S. production of crude oil in the AEO2013 Reference case increases from 5.7 million bpd in 2011 to 7.5 million bpd in 2019, 13 percent higher than in AEO2012 (Figure 10). Despite a decline after 2019, U.S. crude oil production remains above 6.0 million bpd through 2040. Higher production volumes result mainly from increased onshore oil production, predominantly from tight (very low permeability) formations.

In AEO2013, onshore tight oil production accounts for 51 percent of total lower 48 onshore oil production in 2040, up from 33 percent in 2011. As with shale gas, the application of horizontal drilling and hydraulic fracturing significantly increases the development of tight oil resources. Offshore crude oil production trends upward over time, fluctuating between 1.4 and 1.8 million bpd, as the pace of development activity quickens and new large development projects, predominantly in the deepwater and ultra-deepwater portions of the Gulf of Mexico, are brought into production.

The faster growth of tight oil production through 2020 in AEO2013 results in higher domestic crude oil production than in AEO2012 throughout most of the projection. Tight oil production declines after 2020 as more development moves into lower-productivity areas (with lower initial production rates and flatter decline curves), resulting in flattening of production after 2030. Total U.S. liquids production in AEO2013 is higher than in AEO2012 due to increased tight oil production through 2025; however, lower production of biofuels and natural gas plant liquids, as well as the decline in tight oil production beginning in 2021, results in lower levels of total domestic liquids production after 2025 in AEO2013 than in AEO2012.

U.S. dependence on imported liquid fuels continues to decline in the AEO2013 Reference case, primarily as a result of increased domestic oil production. Imported liquid fuels as a share of total U.S. liquid fuel use reached 60 percent in 2005 before dipping below 50 percent in 2010 and falling further to 45 percent in 2011. The import share continues to decline to 34 percent in 2019 and then rises to about 37 percent in 2040, due to a decline in domestic production of tight oil that begins in about 2021 (Figure 11).

Natural gas

Cumulative production of dry natural gas from 2011 through 2035 in the AEO2013 Reference case is about 8 percent higher than in AEO2012, primarily reflecting continued increases in shale gas production that result from the dual application of horizontal drilling and hydraulic fracturing. Another contributing factor is ongoing drilling in shale and other plays with high concentrations of natural gas liquids and crude oil, which, in energy-equivalent terms, have a higher value than dry natural gas. Cumulative production levels for tight gas and coalbed methane exceed those in the AEO2012 Reference case through 2035 by 3 percent and make material contributions to the overall increase in production. Lower 48 offshore natural gas production fluctuates between 1.8 and 2.8 trillion cubic feet per year, about the same as in AEO2012. New, larger-volume development projects, particularly in the deepwater Gulf of Mexico, remain directed principally toward liquids rather than natural gas. Offshore natural gas production is expected to reverse a years-long overall decline in about 2015, however, after which annual volumes generally increase to 2.8 trillion cubic feet in 2035 and remain at about that level through the balance of the projection period.

Figure 9. Total energy production and consumption, 1980-2040 (quadrillion Btu)

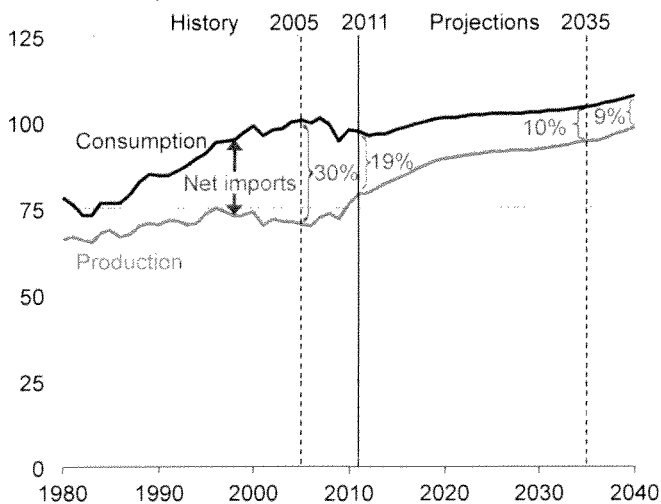
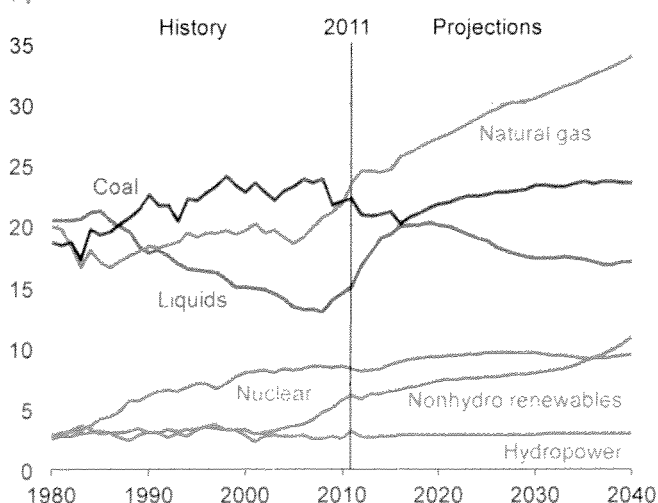


Figure 10. U.S. energy production by fuel, 1980-2040 (quadrillion Btu)



Lower 48 offshore natural gas production fluctuates between 1.8 and 2.8 trillion cubic feet per year, about the same as in AEO2012. New, larger-volume development projects, particularly in the deepwater Gulf of Mexico, remain directed principally toward liquids rather than natural gas. Offshore natural gas production is expected to reverse a years-long overall decline in about 2015, however, after which annual volumes generally increase to 2.8 trillion cubic feet in 2035 and remain at about that level through the balance of the projection period.

In the AEO2013 Reference case, the United States becomes a net exporter of LNG starting in 2016, as it did in the AEO2012

Figure 11. U.S. liquid fuels supply, 1970-2040 (million barrels per day)



Reference case, and an overall net exporter of natural gas in 2020, two years earlier than in AEO2012. U.S. exports of LNG from new liquefaction capacity are assumed to start at a level of 0.6 billion cubic feet per day in 2016 and increase to 4.5 billion cubic feet per day in 2027, as peak export volumes are shipped out of facilities in the Gulf Coast and Alaska. Over the projection period, cumulative net pipeline imports of natural gas from Canada and Mexico in the AEO2013 Reference case are considerably lower than those projected in the AEO2012 Reference case, with the United States becoming a net pipeline exporter of natural gas in 2021, or three years earlier than in AEO2012. In the AEO2013 Reference case, net pipeline imports from Canada fall steadily over most of the projection period, and net pipeline exports to Mexico grow by 387 percent. U.S. cumulative net LNG exports from 2011 through 2035 are up by 69 percent in AEO2013 compared with AEO2012, due in part to increased use of LNG in markets outside North America, strong domestic production, and low U.S. natural gas prices relative to other global markets. As in the AEO2012 Reference case, the Alaska natural gas pipeline is not constructed in the AEO2013 Reference case, because assumed high capital costs and low natural gas prices in the lower 48 states make it uneconomical to proceed with the pipeline project over the projection period.

Coal

While coal remains the leading fuel for U.S. electricity generation, its share of total generation in all years is slightly lower in the AEO2013 Reference case than was projected in the AEO2012 Reference case, and coal consumption in the electricity sector is lower than in AEO2012 in most years of the projection period. While still growing in most years after 2016, coal consumption in the power sector and for the production of coal-based synthetic liquids increases more slowly than in AEO2012; however, higher coal exports combined with lower imports keep the differences in coal production between the AEO2013 and AEO2012 Reference cases relatively small.

In the AEO2013 Reference case, domestic coal production increases at an average rate of only 0.2 percent per year, from 22.2 quadrillion Btu (1,096 million short tons) in 2011 to 23.5 quadrillion Btu (1,167 million short tons) in 2040. Over the projection period, however, production growth is uneven. From 2011 to 2016, low natural gas prices and the retirement of a sizable amount of coal-fired generating capacity lead to a substantial decline in electricity sector coal consumption, which, in turn, contributes to a 2.0-quadrillion-Btu decline in coal production over those years. After 2016, increases in coal use for electricity generation and exports lead to a gradual recovery in U.S. coal production. From 2016 to 2040, coal production grows at an average rate of 0.6 percent per year, from 20.2 quadrillion Btu to 23.5 quadrillion Btu. Regionally, coal producers in both the Interior and Western regions see their shares of total U.S. coal production increase over the projection period, while Appalachia's share declines. From 2011 to 2040, the Appalachian region's share of total coal production (on a Btu basis) falls from 38 percent to 32 percent.

Electricity generation in 2011 accounts for 91 percent of total U.S. coal consumption on a Btu basis. In the AEO2013 Reference case, projected coal consumption in the electric power sector in 2035 (18.5 quadrillion Btu) is 0.6 quadrillion Btu lower than in the AEO2012 Reference case (19.0 quadrillion Btu). The reduced outlook for coal consumption in this sector is generally attributable to lower natural gas prices and higher coal prices that, taken together, support increased generation from natural gas in the AEO2013 Reference case. More generation from nonhydroelectric renewables also contributes to the reduced outlook for electricity sector coal consumption in AEO2013. Coal consumed at CTL plants is lower in this year's outlook, reaching 0.2 quadrillion Btu in 2035 as compared with 1.2 quadrillion Btu in AEO2012. With a more robust outlook for coal imports by Asian countries, AEO2013 shows higher U.S. coal exports than AEO2012.

Total U.S. coal consumption increases from 19.7 quadrillion Btu in 2011 to 20.4 quadrillion Btu in 2040, reflecting average growth of 0.1 percent per year. As with production, growth rates for coal consumption are uneven over the projection, with consumption declining by 2.7 percent per year from 2011 to 2016, but then increasing by 0.7 percent per year from 2016 to 2040.

Electricity generation

Total electricity consumption in the AEO2013 Reference case, including both purchases from electric power producers and on-site generation, grows from 3,841 billion kilowatthours in 2011 to 4,930 billion kilowatthours in 2040, an average annual rate of 0.9 percent—about the same rate as in the AEO2012 Reference case through 2035.

The combination of slow growth in electricity demand, competitively priced natural gas, programs encouraging renewable fuel use, and the implementation of new environmental rules dampens future coal use. The AEO2013 Reference case assumes implementation of the CAIR as a result of an August 2012 federal court decision to vacate the CSAPR. The lower natural gas prices in the early years of the AEO2013 Reference case result in switching from coal to natural gas-fired generation, more than offsetting any increase in coal-fired generation that might have occurred in the absence of CSAPR. AEO2013 continues to model the implementation of the Mercury and Air Toxics Standards (MATS), although the implementation date is assumed to move from 2015 to 2016 due to the large number of plants requesting extensions to comply. Once MATS is in place, SO₂ levels are reduced to well below the levels resulting from either CAIR or CSAPR.

Coal remains the largest energy source for electricity generation throughout the projection period, but its share of total generation declines from 42 percent in 2011 to 35 percent in 2040 (Figure 12). Market concerns about GHG emissions continue to dampen the expansion of coal-fired capacity in the AEO2013 Reference case, even under current laws and policies. Low projected fuel prices for new natural gas-fired plants also affect the relative economics of coal-fired capacity, as does the continued rise in

construction costs for new coal-fired power plants. As retirements far outpace new additions, total coal-fired generating capacity falls from 318 gigawatts in 2011 to 278 gigawatts in 2040 in the AEO2013 Reference case.

Electricity generation using natural gas is higher in the AEO2013 Reference case than was projected in the AEO2012 Reference case because of lower projected natural gas prices. New natural gas-fired plants also are much cheaper to build than new renewable or nuclear plants. In 2016, the year that MATS is assumed to be implemented and coal-fired generation hits its lowest point, natural gas-fired generation in AEO2013 is 10 percent higher than in AEO2012 (and in 2035 it is still 9 percent higher).

Electricity generation from nuclear power plants grows by 14 percent in the AEO2013 Reference case, from 790 billion kilowatthours in 2011 to 903 billion kilowatthours in 2040, accounting for about 17 percent of total generation in 2040 (compared with 19 percent in 2011). Nuclear generating capacity increases from 101 gigawatts in 2011 to a high of 114 gigawatts in 2025 through a combination of new construction (5.5 gigawatts), uprates at existing plants (8.0 gigawatts), and retirements (0.6 gigawatts). After 2025, retirements outpace additions, resulting in a slight decline to 113 gigawatts in 2040. AEO2013 incorporates the latest information about planned nuclear plant construction and continues to use the updated estimate of the potential for capacity uprates at existing units developed for AEO2012. About 7 gigawatts of existing nuclear capacity is retired, primarily after 2030, because not all owners of existing nuclear capacity are expected to apply for and receive license renewals to operate their plants beyond 60 years.

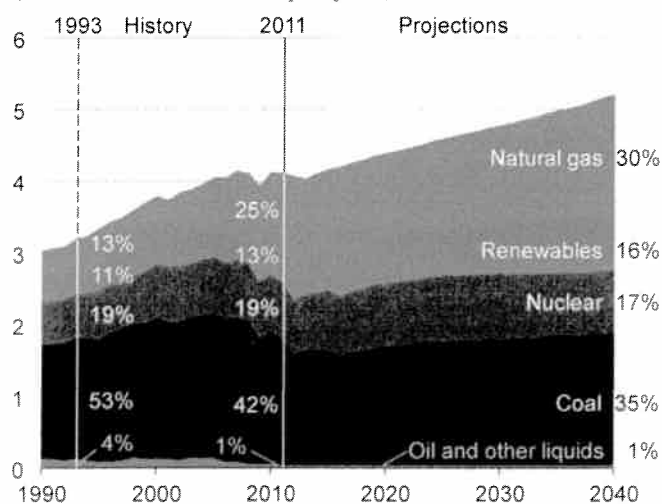
Increased generation from renewable energy, excluding hydropower, accounts for 32 percent of the overall growth in electricity generation from 2011 to 2040. Generation from renewable resources grows in response to federal tax credits, state-level policies, and federal requirements to use more biomass-based transportation fuels, some of which can produce electricity as a byproduct of their production process. Capital costs for new technologies were updated for AEO2013, resulting in fairly significant initial cost reductions for wind (13 percent) and solar PV (22 percent) relative to AEO2012. Reported renewable capacity already under construction has increased in recent years and is represented in AEO2013. Growth in renewable generation is supported by many state requirements, as well as new regulations on CO₂ emissions in California. The share of U.S. electricity generation coming from renewable fuels (including conventional hydropower) grows from 13 percent in 2011 to 16 percent in 2040. In the AEO2013 Reference case, federal subsidies for renewable generation are assumed to expire as enacted. Extensions of such subsidies could have a large impact on renewable generation. The long-run projections for renewable capacity are also sensitive to natural gas prices and the relative costs of alternative generation sources.

Energy-related CO₂ emissions

Total U.S. energy-related CO₂ emissions do not return to their 2005 level (5,997 million metric tons) by the end of the AEO2013 projection period.⁶ Growth in demand for transportation fuels is moderated by rising fuel prices and new, stricter federal CAFE standards for model years 2017 to 2025, which reduce transportation emissions from 2018 until they begin to rise near the end of the projection period. Transportation emissions in 2040 are 26 million metric tons below the 2011 level. Largely as a result of the inclusion of the new CAFE standards in AEO2013, transportation-related CO₂ emissions in 2035 are 94 million metric tons below their level in the AEO2012 Reference case.

State RPS requirements and abundant low-cost natural gas help shift the fuel mix for electricity generation away from coal and reduce emissions in both the residential and commercial sectors from the levels in AEO2012. Growth in residential sector emissions is flat over the projection period, and commercial sector emissions rise only slightly, by 0.3 percent annually.

Figure 12. Electricity generation by fuel, 1990-2040
(trillion kilowatthours per year)

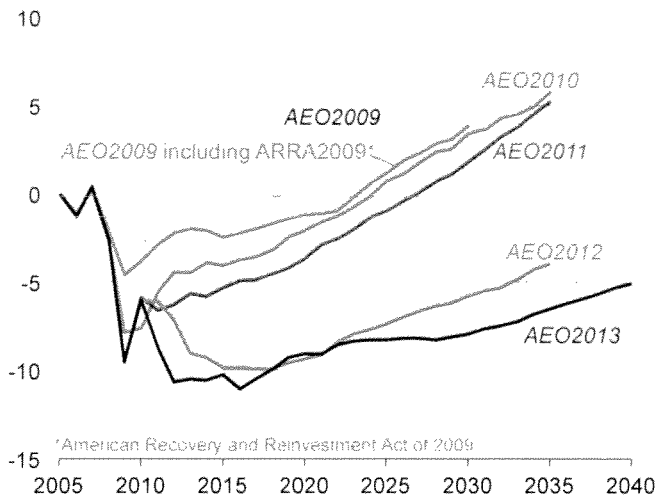


Only industrial energy-related CO₂ emissions are higher in AEO2013 as compared to AEO2012. While industrial coal emissions in AEO2013 are 48 million metric tons lower than in AEO2012 by 2035, natural gas emissions from the industrial sector are 67 million metric tons higher by 2035, and electricity-related emissions allocated to the industrial sector are 77 million metric tons higher. With emissions from petroleum slightly lower, the net result is that industrial sector emissions are 80 million metric tons higher in the AEO2013 Reference case than in AEO2012. Over the projection period from 2011 to 2040, industrial emissions grow at a rate of 0.3 percent annually.

The projected growth rate for U.S. energy-related CO₂ emissions has declined successively in each *Annual Energy Outlook* since AEO2005 (see Figure 13, which shows projections starting with AEO2009), reflecting both market and policy drivers. Using 2030 as a common year, the AEO2006 projection for total energy-related CO₂ emissions was 8,114 million metric tons, with coal accounting for 3,226

⁶The year 2005 is the base year for the Obama Administration's goal for emission reductions of 17 percent by 2020. In 2020, energy-related CO₂ emissions in the AEO2013 Reference case are 9 percent below their 2005 level.

Figure 13. U.S. energy-related carbon dioxide emissions in recent AEO Reference cases (percent change from 2005)



million metric tons (40 percent) and natural gas 1,452 million metric tons (18 percent). In AEO2010, total energy-related CO₂ emissions had dropped to 6,176 million metric tons in 2030, with 2,296 million metric tons (37 percent) coming from coal and 1,315 million metric tons (21 percent) from natural gas. In AEO2013, the 2030 values have fallen to 5,523 million metric tons for total energy-related CO₂ emissions, with 1,874 million metric tons (34 percent) coming from coal and 1,468 metric tons (27 percent) from natural gas. The change reflects both market and policy factors, including the adoption of tighter economy fuel standards, the implementation of efficiency standards, and a continued shift to less carbon-intensive fuels.

List of Acronyms

AB 32	Global Warming Solutions Act of 2006	LDVs	Light-duty vehicles
AEO	<i>Annual Energy Outlook</i>	LFMM	Liquid Fuel Market Module
AEO2011	<i>Annual Energy Outlook 2011</i>	LNG	Liquefied natural gas
AEO2012	<i>Annual Energy Outlook 2012</i>	MACT	Maximum achievable control technology
AEO2013	<i>Annual Energy Outlook 2013</i>	MATS	Mercury and Air Toxics Standards
bpd	barrels per day	mpg	miles per gallon
Btu	British thermal units	NGL	Natural gas liquids
CAFE	Corporate average fuel economy	NHTSA	National Highway Traffic Safety Administration
CAIR	Clean Air Interstate Rule	NO _x	Nitrogen oxides
CHP	Combined heat and power	OCS	Outer Continental Shelf
CO ₂	Carbon dioxide	OECD	Organization for Economic Cooperation and Development
CTL	Coal-to-liquids	OPEC	Organization of the Petroleum Exporting Countries
CSAPR	Cross-State Air Pollution Rule	PV	Photovoltaics
EIA	U.S. Energy Information Administration	RFS	Renewable fuel standard
EISA2007	Energy Independence and Security Act of 2007	RPS	Renewable portfolio standard
EOR	Enhanced oil recovery	SO ₂	Sulfur dioxide
EPA	U.S. Environmental Protection Agency	TRR	Technically recoverable resource
FFV	Flex-fuel vehicle	USGS	United States Geological Survey
GDP	Gross domestic product	WTI	West Texas Intermediate
GHG	Greenhouse gas		
GTL	Gas-to-liquids		

Table 1. Comparison of projections in the *AEO2013* and *AEO2012* Reference cases, 2010-2040

Energy and economic factors	2010	2011	2025 AEO2013	2035 AEO2012	2035 AEO2013	2040 AEO2012	2040 AEO2013
Primary energy production (quadrillion Btu)							
Petroleum	14.37	15.05	18.70	17.69	17.27	16.82	17.01
Dry natural gas	21.82	23.51	29.22	26.91	32.04	28.60	33.87
Coal	22.04	22.21	22.54	22.25	23.60	24.14	23.54
Nuclear/Uranium	8.43	8.26	9.54	9.60	9.14	9.28	9.44
Hydropower	2.54	3.17	2.86	2.99	2.90	3.04	2.92
Biomass	4.05	4.05	5.27	6.26	5.83	9.07	6.96
Other renewable energy	1.31	1.58	2.32	2.22	2.91	2.81	3.84
Other	0.76	1.20	0.85	0.69	0.90	0.91	0.89
Total	75.31	79.02	91.29	88.61	94.59	94.67	98.46
Net imports (quadrillion Btu)							
Liquid fuels and other petroleum ^a	20.53	18.62	15.89	15.85	16.00	16.09	15.99
Natural gas (- indicates exports)	2.69	2.02	-1.56	-0.76	-2.53	-1.33	-3.55
Coal/other (- indicates exports)	-1.58	-2.32	-3.02	-1.75	-3.32	-2.32	-2.95
Total	21.64	18.31	11.31	13.34	10.14	12.44	9.49
Consumption (quadrillion Btu)							
Liquid fuels and other petroleum ^a	37.76	37.02	36.87	36.58	35.82	37.70	36.07
Natural gas	24.32	24.91	27.28	26.14	29.06	27.26	29.83
Coal	20.81	19.66	19.35	20.02	20.09	21.15	20.35
Nuclear/Uranium	8.43	8.26	9.54	9.60	9.14	9.28	9.44
Hydropower	2.54	3.17	2.86	2.99	2.90	3.04	2.92
Biomass	2.87	2.74	3.82	4.17	4.23	5.44	4.91
Other renewable energy	1.31	1.58	2.32	2.22	2.91	2.81	3.84
Other	0.31	0.35	0.30	0.28	0.26	0.24	0.29
Total	98.35	97.70	102.34	101.99	104.41	106.93	107.64
Liquid fuels (million barrels per day)							
Domestic crude oil production	5.47	5.67	6.79	6.40	6.26	5.99	6.13
Other domestic production	4.25	4.74	5.63	5.75	5.56	6.75	5.83
Net imports	9.43	8.51	7.08	7.14	7.06	7.25	7.00
Consumption	19.17	18.95	19.50	19.20	18.86	19.90	18.95
Natural gas (trillion cubic feet)							
Dry gas production + supplemental gas	21.40	23.06	28.65	26.34	31.41	27.99	33.21
Net imports (- indicates exports)	2.60	1.95	-1.58	-0.79	-2.55	-1.36	-3.55
Consumption	23.78	24.37	26.87	25.53	28.71	26.63	29.54
Coal (million short tons)							
Production and waste coal	1,098	1,108	1,134	1,134	1,194	1,231	1,195
Net exports	64	96	124	71	136	94	123
Consumption	1,049	999	1,010	1,063	1,058	1,137	1,071

**Table 1. Comparison of projections in the AEO2013 and AEO2012 Reference cases, 2010-2040
(continued)**

	2025				2035		2040
Energy and economic factors	2010	2011	AEO2013	AEO2012	AEO2013	AEO2012	AEO2013
Prices (2011 dollars)							
Brent spot crude oil (dollars per barrel)	81.31	111.26	117.36	--	145.41	--	162.68
West Texas Intermediate spot crude oil (dollars per barrel)	81.08	94.86	115.36	135.35	143.41	148.03	160.68
Natural gas at Henry Hub (dollars per million Btu)	4.46	3.98	4.87	5.75	6.32	7.52	7.83
Domestic coal at minemouth (dollars per short ton)	36.37	41.16	52.02	44.97	58.57	51.59	61.28
Average electricity price (cents per kilowatthour)	10.0	9.9	9.5	9.9	10.1	10.3	10.8
Economic indicators							
Real gross domestic product (billion 2005 dollars)	13,063	13,299	18,985	19,185	24,095	24,539	27,277
GDP chain-type price index (2005 = 1.000)	1.110	1.134	1.429	1.424	1.713	1.758	1.871
Real disposable personal income (billion 2005 dollars)	10,017	10,150	14,259	14,286	17,752	18,217	19,785
Value of industrial shipments (billion 2005 dollars)	5,842	6,019	8,548	7,973	9,779	8,692	10,616
Primary energy intensity (thousand Btu per 2005 dollar of GDP)	7.53	7.35	5.39	5.32	4.33	4.36	3.95
Energy-related carbon dioxide emissions (million metric tons)	5,634	5,471	5,501	5,552	5,607	5,758	5,691

^aIncludes petroleum-derived fuels and non-petroleum-derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids and crude oil consumed as a fuel.

-- = not applicable.

Notes: Quantities reported in quadrillion Btu are derived from historical volumes and assumed thermal conversion factors. Other production includes liquid hydrogen, methanol, and some inputs to refineries. Net imports of petroleum include crude oil, petroleum products, unfinished oils, alcohols, ethers, and blending components. Other net imports include coal coke and electricity. Both coal consumption and coal production include waste coal consumed in the electric power and industrial sectors.

Sources: AEO2013 National Energy Modeling System, run REF2013.D102312A; and AEO2012 National Energy Modeling System, run REF2012.D020112C.