7. Coal

The next three chapters cover the representation and underlying assumptions for fuels in EPA 2023 Reference Case. Chapter 7 focuses on coal, Chapter 8 on natural gas, and Chapter 9 on other fuels (fuel oil, biomass, nuclear fuel, and waste fuels).

This chapter presents four main topics. The first topic discusses how the coal market is represented. Included are discussions of coal supply and demand regions, coal quality characteristics, and the assignment of coal to power plants.

The second topic concerns coal supply curves which were developed using a bottom-up, mine-based approach. The approach depicts the coal choices and associated prices that power plants face over the modeling time horizon. Included are discussions of the methods and data used to quantify the economically recoverable coal reserves, characterize their cost, and build the 71 coal supply curves implemented in EPA 2023 Reference Case. Also, step-by-step illustrative examples of the approach are provided.

The third topic covers coal transportation. Included are discussions of the transport network, the methodology used to assign costs to the links in the network, and the geographic, infrastructure, and regulatory considerations that come into play in developing specific rail, barge, and truck transport rates.

Finally, issues concerning competition among sources of coal supply and demand are addressed. Competition on the supply side includes imported coal that arrives from non-U.S. or non-Canadian basins. Competition on the demand side includes demand for international thermal exports, as well as domestic industrial, residential, and commercial demand for thermal coal. These assumptions are discussed in Section 7.4.

The assumptions for the coal supply curves and coal transportation were finalized in January 2021, and were developed through a collaborative process with EPA supported by the following independent team of coal experts (with key areas of responsibility noted in parenthesis): ICF (IPM model integration and team coordination), Wood Mackenzie (coal supply curve development), and Hellerworx (coal transportation cost development).

7.1 Coal Market Representation

Coal supply, coal demand, coal quality, and the assignment of specific types of coals to individual coal-fired generating units are the four key components of the endogenous coal market modeling framework in EPA 2023 Reference Case. The modeling representation attempts to reflect the actual options available to each existing coal-fired power plant while aggregating data sufficiently to keep the model size and solution time within acceptable limits.

Each coal-fired power plant modeled is reflected as its own coal demand region. The demand regions are defined to reflect the coal transportation options, including rail, barge, truck, and conveyor belt, that are available to the plant. These demand regions are interconnected by a transportation network to at least one of the 34 geographically dispersed coal supply regions. The model's supply-demand region links reflect actual on-the-ground transportation pathways. Each coal supply region can supply, and each coal demand region can demand at least one grade of coal. Based on historical and engineering data (as described in Section 7.1.5), each coal-fired power plant is also assigned several coal grades, which it may use if available within its demand region.

The endogenous demand for coal is generated by coal-fired power plants interacting with a set of exogenous supply curves (see Table 7-26 for coal supply curve data) for each coal grade in each supply region. The curves show the supply of coal (by coal supply region and coal grade) that is available to meet the demand at a given price. The supply and demand for each coal grade is linked to and affected by the supply and demand for every other coal grade across supply and demand regions. The transportation network, which is also called the coal transportation matrix, in Table 7-25 provides the delivery cost to move coal from a free-on-board point of sale in the coal basin to the end-use power plant. The transportation cost combined with the free-on-board supply cost reflects the delivered cost a plant considers when making its coal selection. IPM derives the equilibrium coal consumption and prices that result when the entire electric system is operating at the least cost while meeting emission constraints and other operating requirements over the modeling time horizon.

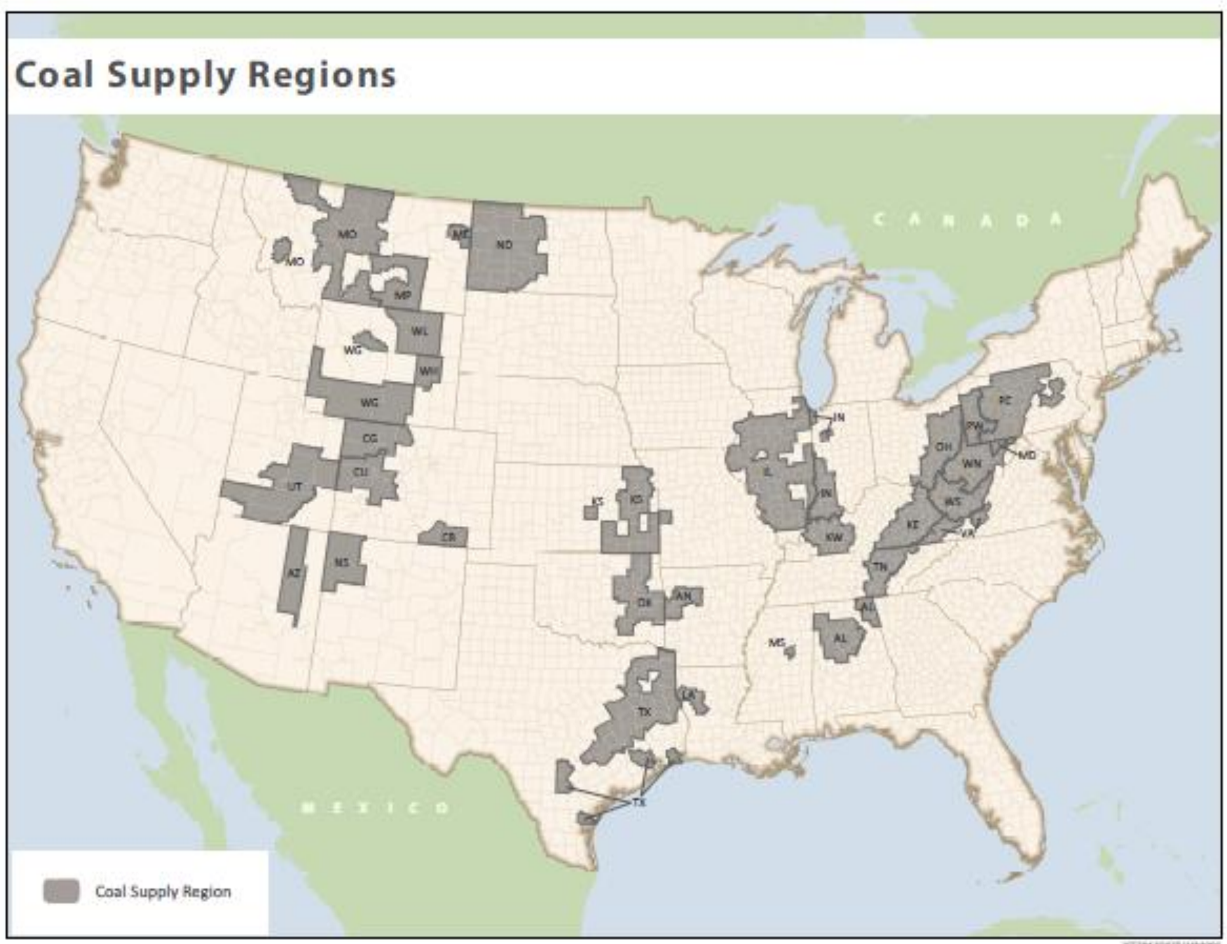
7.1.1 Coal Supply Regions

There are 34 coal supply regions, each representing geographic aggregations of coal-mining areas that supply one or more coal grades. Coal supply regions may differ from one another in the types and quality of coal they can supply. Table 7-1 lists the coal supply regions included in EPA 2023 Reference Case. Figure 7-1 provides a map showing the location of the coal supply regions listed in Table 7-1 and the broader supply basins commonly used when referring to U.S. coal reserves.

Table 7-1 Coal Supply Regions in EPA 2023 Reference Case

Region	State	Supply Region
Central Appalachia	Kentucky, East	KE
Central Appalachia	Tennessee	TN
Central Appalachia	Virginia	VA
Central Appalachia	West Virginia, South	WS
Dakota Lignite	Montana, East	ME
Dakota Lignite	North Dakota	ND
East Interior	Indiana	IN
East Interior	Kentucky, West	KW
East Interior	Illinois	IL
Gulf Lignite	Texas	TX
Gulf Lignite	Louisiana	LA
Gulf Lignite	Mississippi	MS
Northern Appalachia	Maryland	MD
Northern Appalachia	Ohio	OH
Northern Appalachia	Pennsylvania, Central	PC
Northern Appalachia	Pennsylvania, West	PW
Northern Appalachia	West Virginia, North	WN
Rocky Mountains	Utah	UT
Rocky Mountains	Colorado, Green River	CG
Rocky Mountains	Colorado, Raton	CR
Rocky Mountains	Colorado, Uinta	CU
Southern Appalachia	Alabama	AL
Southwest	Arizona	AZ
Southwest	New Mexico, San Juan	NS
West Interior	Oklahoma	OK
Western Montana	Montana, Bull Mountains	MT
Western Montana	Montana, Powder River	MP
Western Wyoming	Wyoming, Green River	WG
Wyoming Northern PRB	Wyoming, Powder River Basin (8800)	WH
Wyoming Southern PRB	Wyoming, Powder River Basin (8400)	WL
Alaska	Alaska	AK
Alberta	Alberta	AB
British Columbia	British Columbia	BC
Saskatchewan	Saskatchewan	SK

Figure 7-1 Map of the Coal Supply Regions in the EPA 2023 Reference Case



7.1.2 Coal Demand Regions

Coal demand regions are designed to reflect coal transportation options available to power plants. Each existing coal-fired power plant is reflected as its own individual demand region. The transportation infrastructure (i.e., rail, barge, truck, or conveyor belt), proximity to mine (i.e., mine mouth or not mine mouth), and transportation competitiveness levels (i.e., non-competitive, low-cost competitive, or high-cost competitive) are developed specific to each plant (demand region).

IPM determines the amount and type of new generation capacity to add within each of the 67 U.S. IPM model regions. The model regions reflect the administrative, operational, and transmission geographic structure of the U.S. electricity grid. Since new plants could be located at various locations within a region, a generic transportation cost for different coal types is developed for these new plants. The methodology for deriving that cost is described in Section 7.3.

7.1.3 Coal Quality Characteristics

Coal varies by heat content, SO_2 content, HCl content, and mercury content, among other characteristics. A two-letter coal grade nomenclature is used to capture differences in the sulfur and heat content of coal. The first letter indicates the coal rank (i.e., bituminous, subbituminous, or lignite) with their associated heat content ranges (as shown in Table 7-2). The second letter indicates their sulfur grade, (i.e., the SO_2 ranges associated with a given type of coal). The sulfur grades and associated SO_2 ranges are shown in Table 7-3.

Table 7-2 Coal Rank Heat Content Ranges

Coal Type	Heat Content (Btu/lb)	Classification
Bituminous	>10,260 – 13,000	B
Subbituminous	> 7,500 – 10,260	S
Lignite	less than 7,500	L

Table 7-3 Coal Grade SO_2 Content Ranges

SO_2 Grade	SO_2 Content Range (lbs/MMBtu)
A	0.00 – 0.80
B	0.81 – 1.20
D	1.21 – 1.66
E	1.67 – 3.34
G	3.35 – 5.00
H	> 5.00

The EPA 2023 Reference Case assumptions on the heat, HCl, mercury, SO_2, and ash contents of coal are derived from EPA's Information Collection Request for Electric Utility Steam Generating Unit Mercury Emissions Information Collection Effort (ICR).[64]

A two-year effort initiated in 1998 and completed in 2000, the ICR had three main components: (1) identifying all coal-fired units owned and operated by publicly-owned utility companies, federal power agencies, rural electric cooperatives, and investor-owned utility generating companies, (2) obtaining "accurate information on the amount of mercury contained in the as-fired coal used by each electric utility steam generating unit with a capacity greater than 25 megawatts electric, as well as accurate information on the total amount of coal burned by each such unit,", and (3) obtaining data by coal sampling and stack testing at selected units to characterize mercury reductions from representative unit configurations. Data regarding the coal's SO_2, chlorine, and ash contents was obtained along with mercury content. The ICR captured the origin of the coal burned and thus provided a pathway for linking emission properties to coal basins.

The 1998-2000 ICR resulted in more than 40,000 data points indicating the coal type, sulfur content, mercury content, ash content, chlorine content, and other characteristics of coal burned at coal-fired utility boilers greater than 25 MW.

Annual fuel characteristic and delivery data reported on EIA Form 923 also provide data points on coal heat content, sulfur content, and geographic origin, which are used to check against characteristics initially identified through the ICR.

7.1.4 Coal Emission Factors

To make the data usable in EPA 2023 Reference Case, the ICR data points were first grouped by IPM coal grades and IPM coal supply regions. Using the grouped ICR data, the average heat, SO_2, mercury, HCl, and ash contents were calculated for each coal grade and supply region combination. In instances where no data was available for a particular coal grade in a specific supply region, the national average SO_2 and mercury values for the coal grade were used. The coal characteristics of Canadian coal supply regions are based on the coal characteristics of the adjacent U.S. coal supply regions. The resulting values are shown in Table 7-4. The CO_2 values were derived from data in the Energy Information Administration's Annual Energy Outlook 2016.

[64] Data from the ICR can be found at http://www.epa.gov/ttn/atw/combust/utiltox/mercury.html

Table 7-4 Coal Quality Characteristics by Supply Region and Coal Grade in the EPA 2023 Reference Case

Coal Supply Region	Coal Grade	SO_2 Content (lbs/MMBtu)	Mercury Content (lbs/TBtu)	Ash Content (lbs/MMBtu)	HCl Content (lbs/MMBtu)	CO_2 Content (lbs/MMBtu)	Cluster Number
AB	SA	0.59	5.29	5.47	0.009	215.5	1
	SB	0.94	6.06	6.94	0.013	215.5	4
	SD	1.43	5.35	11.60	0.008	215.5	1
AK	SA	0.59	5.29	5.47	0.009	216.1	1
AL	BB	1.09	4.18	9.76	0.012	204.7	4
	BD	1.35	7.28	10.83	0.029	204.7	1
	BE	2.68	12.58	10.70	0.028	204.7	1
AZ	BB	1.05	5.27	7.86	0.067	207.1	2
BC	BD	1.40	6.98	8.34	0.096	216.1	3
CG	BB	0.90	4.09	8.42	0.021	209.6	4
	SB	0.93	2.03	7.06	0.007	212.8	1
CR	BB	1.05	5.27	7.86	0.067	209.6	2
CU	BB	0.86	4.01	7.83	0.009	209.6	4
IL	BE	2.25	6.52	6.61	0.214	203.1	2
	BG	4.56	6.53	8.09	0.113	203.1	3
	BH	5.58	5.43	9.06	0.103	203.1	1
IN	BE	2.31	5.21	7.97	0.036	203.1	3
	BG	4.27	7.20	8.22	0.028	203.1	3
	BH	6.15	7.11	8.63	0.019	203.1	3
KE	BB	1.04	4.79	6.41	0.112	206.4	5
	BD	1.44	5.97	7.45	0.087	206.4	2
	BE	2.12	7.93	7.71	0.076	206.4	4
KW	BG	4.46	6.90	8.01	0.097	203.1	3
	BH	5.73	8.16	10.21	0.053	203.1	3
LA	LE	2.49	7.32	17.15	0.014	212.6	1
MD	BE	2.78	15.62	11.70	0.072	204.7	5
	BG	3.58	16.64	16.60	0.018	204.7	5
ME	LE	1.83	11.33	11.69	0.019	219.3	2
MP	SA	0.62	4.24	3.98	0.007	215.5	1
	SD	1.49	4.53	10.13	0.006	215.5	1
MS	LE	2.76	12.44	21.51	0.018	216.5	3
MT	BB	1.05	5.27	7.86	0.067	215.5	2
ND	LE	2.27	8.30	12.85	0.014	219.3	1
NS	SB	0.89	4.60	14.51	0.014	209.2	2
	SD	1.55	7.54	23.09	0.007	209.2	2
	SE	1.90	8.65	23.97	0.008	209.2	1
OH	BE	3.08	18.70	7.08	0.075	204.7	6
	BG	3.99	18.54	8.00	0.071	204.7	5
	BH	6.43	13.93	9.13	0.058	204.7	4
OK	BG	4.65	26.07	13.54	0.051	202.8	4
PC	BE	2.57	17.95	9.23	0.096	204.7	6
	BG	3.79	21.54	9.59	0.092	204.7	2
	BH	6.29	34.71	13.89	0.148	204.7	5
PW	BE	2.51	8.35	5.37	0.090	204.7	4
	BG	3.69	8.56	6.48	0.059	204.7	1
	BH	7.78	16.46	11.56	0.046	204.7	2
SK	LD	1.51	7.53	11.57	0.014	219.3	1

Coal Supply Region	Coal Grade	SO_2 Content (lbs/MMBtu)	Mercury Content (lbs/TBtu)	Ash Content (lbs/MMBtu)	HCl Content (lbs/MMBtu)	CO_2 Content (lbs/MMBtu)	Cluster Number
	LE	2.76	12.44	21.51	0.018	219.3	3
TN	BB	1.14	3.78	10.35	0.083	206.4	3
	BE	2.13	8.43	6.47	0.043	206.4	4
TX	LE	3.00	14.65	25.65	0.020	212.6	4
	LG	3.91	14.88	25.51	0.036	212.6	1
	LH	5.67	30.23	23.95	0.011	212.6	1
UT	BA	0.67	4.37	7.39	0.015	209.6	1
	BB	0.94	3.93	8.58	0.016	209.6	4
	BD	1.37	4.38	10.50	0.026	209.6	3
	BE	2.34	9.22	7.41	0.095	209.6	4
VA	BB	1.05	4.61	6.97	0.054	206.4	5
	BD	1.44	5.67	7.97	0.028	206.4	2
	BE	2.09	8.40	8.05	0.028	206.4	4
WG	BB	1.13	1.82	5.58	0.005	214.3	3
	SB	1.06	4.22	8.72	0.009	214.3	3
	SD	1.33	4.33	10.02	0.008	214.3	1
WH	SA	0.52	5.61	5.51	0.010	214.3	2
WL	SA	0.71	5.61	7.09	0.010	214.3	3
	SB	0.93	6.44	7.92	0.012	214.3	4
WN	BE	2.55	10.28	7.89	0.092	204.7	7
	BH	6.09	8.82	9.62	0.045	204.7	3
WS	BB	1.09	5.75	9.15	0.091	206.4	1
	BD	1.32	8.09	9.25	0.098	206.4	4
	BE	1.94	8.83	9.89	0.102	206.4	4

Next, a clustering algorithm was used to further aggregate the data for model size management purposes. Using the SAS statistical software package, the clustering analysis was performed on the SO_2, mercury, and HCl content data shown in Table 7-4. Clustering analysis places objects into groups or clusters such that data in a given cluster tend to be similar to each other and dissimilar to data in other clusters. The clustering analysis involved two steps. First, the number of clusters of SO_2, mercury, and HCl contents for each coal grade was determined based on the range in SO_2, mercury, and HCl contents across all coal supply regions. Each coal grade used one to seven clusters. The number of clusters for each coal grade was limited to keep the model size and run time within acceptable limits. Second, for each coal grade, the clustering procedure was applied to all the regional SO_2, mercury, and HCl contents shown in Table 7-4. Using the SAS cluster procedure, each of the constituent regional contents was assigned to a cluster, and the cluster average SO_2, mercury, and HCl contents were estimated. The resulting contents are shown in Table 7-5 through Table 7-9.

Table 7-5 Coal Clustering by Coal Grade – SO_2 Emission Factors (lbs/MMBtu)

Coal Type by Sulfur Grade	SO_2 Emission Factors (lbs/MMBtu)																				
	Cluster #1			Cluster #2			Cluster #3			Cluster #4			Cluster # 5			Cluster # 6			Cluster # 7		
	Cluster Value	Data Range Low	Data Range High	Cluster Value	Data Range Low	Data Range High	Cluster Value	Data Range Low	Data Range High	Cluster Value	Data Range Low	Data Range High	Cluster Value	Data Range Low	Data Range High	Cluster Value	Data Range Low	Data Range High	Cluster Value	Data Range Low	Data Range High
Low Sulfur Bituminous (BA)	0.67	0.67	0.67	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Low Sulfur Bituminous (BB)	1.10	1.09	1.10	1.05	1.05	1.05	1.14	1.13	1.14	0.95	0.86	1.09	1.04	1.04	1.05	--	--	--	--	--	--
Low Medium Sulfur Bituminous (BD)	1.35	1.35	1.35	1.44	1.44	1.44	--	--	--	1.39	1.37	1.40	1.32	1.32	1.32	--	--	--	--	--	--
Medium Sulfur Bituminous (BE)	2.68	2.68	2.68	2.25	2.25	2.25	2.31	2.31	2.31	2.19	1.94	2.51	2.78	2.78	2.78	2.82	2.57	3.08	2.55	2.55	2.55
High Sulfur Bituminous (BG)	3.69	3.69	3.69	3.79	3.79	3.79	4.43	4.27	4.56	--	--	--	--	--	--	4.65	4.65	4.65	3.78	3.58	3.99
High Sulfur Bituminous (BH)	5.58	5.58	5.58	7.78	7.78	7.78	5.99	5.73	6.15	6.43	6.43	6.43	6.29	6.29	6.29	--	--	--	--	--	--
Low Sulfur Subbituminous (SA)	0.60	0.59	0.62	0.52	0.52	0.52	0.71	0.71	0.71	--	--	--	--	--	--	--	--	--	--	--	--
Low Sulfur Subbituminous (SB)	0.93	0.93	0.93	--	--	--	0.89	0.89	0.89	1.06	1.06	1.06	0.94	0.93	0.94	--	--	--	--	--	--
Low Medium Sulfur Subbituminous (SD)	1.42	1.33	1.49	1.55	1.55	1.55	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Medium Sulfur Subbituminous (SE)	1.90	1.90	1.90	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Low Medium Sulfur Lignite (LD)	1.51	1.51	1.51	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Medium Sulfur Lignite (LE)	2.38	2.27	2.49	1.83	1.83	1.83	2.76	2.76	2.76	3.00	3.00	3.00	--	--	--	--	--	--	--	--	--
High Sulfur Lignite (LG)	3.91	3.91	3.91	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
High Sulfur Lignite (LH)	5.67	5.67	5.67	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--

Table 7-6 Coal Clustering by Coal Grade – Mercury Emission Factors (lbs/TBtu)

Coal Type by Sulfur Grade	Mercury Emission Factors (lbs/TBtu)																				
	Cluster #1			Cluster #2			Cluster #3			Cluster #4			Cluster # 5			Cluster # 6			Cluster # 7		
	Cluster Value	Data Range Low	Data Range High	Cluster Value	Data Range Low	Data Range High	Cluster Value	Data Range Low	Data Range High	Cluster Value	Data Range Low	Data Range High	Cluster Value	Data Range Low	Data Range High	Cluster Value	Data Range Low	Data Range High	Cluster Value	Data Range Low	Data Range High
Low Sulfur Bituminous (BA)	4.37	4.37	4.37	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Low Sulfur Bituminous (BB)	6.74	5.75	7.74	5.27	5.27	5.27	2.80	1.82	3.78	4.05	3.93	4.18	4.70	4.61	4.79	--	--	--	--	--	--
Low Medium Sulfur Bituminous (BD)	7.28	7.28	7.28	5.82	5.67	5.97	--	--	--	5.68	4.38	6.98	8.09	8.09	8.09	--	--	--	--	--	--
Medium Sulfur Bituminous (BE)	12.58	12.58	12.58	6.52	6.52	6.52	5.21	5.21	5.21	8.53	7.93	9.22	15.62	15.62	15.62	18.33	17.95	18.70	10.28	10.28	10.28
High Sulfur Bituminous (BG)	8.56	8.56	8.56	21.54	21.54	21.54	6.88	6.53	7.20	--	--	--	--	--	--	26.07	26.07	26.07	17.59	16.64	18.54
High Sulfur Bituminous (BH)	5.43	5.43	5.43	16.46	16.46	16.46	8.03	7.11	8.82	13.93	13.93	13.93	34.71	34.71	34.71	--	--	--	--	--	--
Low Sulfur Subbituminous (SA)	4.94	4.24	5.29	5.61	5.61	5.61	5.61	5.61	5.61	--	--	--	--	--	--	--	--	--	--	--	--
Low Sulfur Subbituminous (SB)	2.03	2.03	2.03	--	--	--	4.60	4.60	4.60	4.22	4.22	4.22	6.25	6.06	6.44	--	--	--	--	--	--
Low Medium Sulfur Subbituminous (SD)	4.74	4.33	5.35	7.54	7.54	7.54	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Medium Sulfur Subbituminous (SE)	8.65	8.65	8.65	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Low Medium Sulfur Lignite (LD)	7.53	7.53	7.53	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Medium Sulfur Lignite (LE)	7.81	7.32	8.30	11.33	11.33	11.33	12.44	12.44	12.44	14.65	14.65	14.65	--	--	--	--	--	--	--	--	--
High Sulfur Lignite (LG)	14.88	14.88	14.88	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
High Sulfur Lignite (LH)	30.23	30.23	30.23	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--

Table 7-7 Coal Clustering by Coal Grade – Ash Emission Factors (lbs/MMBtu)

Coal Type by Sulfur Grade	Ash Emission Factors (lbs/MMBtu)																				
	Cluster #1			Cluster #2			Cluster #3			Cluster #4			Cluster # 5			Cluster # 6			Cluster # 7		
	Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range	
		Low	High		Low	High		Low	High		Low	High		Low	High		Low	High		Low	High
Low Sulfur Bituminous (BA)	7.39	7.39	7.39	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Low Sulfur Bituminous (BB)	6.98	4.81	9.15	7.86	7.86	7.86	7.97	5.58	10.35	8.65	7.83	9.76	6.69	6.41	6.97	--	--	--	--	--	--
Low Medium Sulfur Bituminous (BD)	10.83	10.83	10.83	7.71	7.45	7.97	--	--	--	9.42	8.34	10.50	9.25	9.25	9.25	--	--	--	--	--	--
Medium Sulfur Bituminous (BE)	10.70	10.70	10.70	6.61	6.61	6.61	7.97	7.97	7.97	7.48	5.37	9.89	11.70	11.70	11.70	8.16	7.08	9.23	7.89	7.89	7.89
High Sulfur Bituminous (BG)	6.48	6.48	6.48	9.59	9.59	9.59	8.10	8.01	8.22	--	--	--	--	--	--	13.54	13.54	13.54	12.30	8.00	16.60
High Sulfur Bituminous (BH)	9.06	9.06	9.06	11.56	11.56	11.56	9.49	8.63	10.21	9.13	9.13	9.13	13.89	13.89	13.89	--	--	--	--	--	--
Low Sulfur Subbituminous (SA)	4.97	3.98	5.47	5.51	5.51	5.51	7.09	7.09	7.09	--	--	--	--	--	--	--	--	--	--	--	--
Low Sulfur Subbituminous (SB)	7.06	7.06	7.06	--	--	--	14.51	14.51	14.51	8.72	8.72	8.72	7.43	6.94	7.92	--	--	--	--	--	--
Low Medium Sulfur Subbituminous (SD)	10.58	10.02	11.60	23.09	23.09	23.09	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Medium Sulfur Subbituminous (SE)	23.97	23.97	23.97	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Low Medium Sulfur Lignite (LD)	11.57	11.57	11.57	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Medium Sulfur Lignite (LE)	15.00	12.85	17.15	11.69	11.69	11.69	21.51	21.51	21.51	25.65	25.65	25.65	--	--	--	--	--	--	--	--	--
High Sulfur Lignite (LG)	25.51	25.51	25.51	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
High Sulfur Lignite (LH)	23.95	23.95	23.95	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--

Table 7-8 Coal Clustering by Coal Grade – HCl Emission Factors (lbs/MMBtu)

Coal Type by Sulfur Grade	HCl Emission Factors (lbs/MMBtu)																				
	Cluster #1			Cluster #2			Cluster #3			Cluster #4			Cluster # 5			Cluster # 6			Cluster # 7		
	Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range	
		Low	High		Low	High		Low	High		Low	High		Low	High		Low	High		Low	High
Low Sulfur Bituminous (BA)	0.015	0.015	0.015	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Low Sulfur Bituminous (BB)	0.054	0.018	0.091	0.067	0.067	0.067	0.044	0.005	0.083	0.015	0.009	0.021	0.083	0.054	0.112	--	--	--	--	--	--
Low Medium Sulfur Bituminous (BD)	0.029	0.029	0.029	0.057	0.028	0.087	--	--	--	0.061	0.026	0.096	0.098	0.098	0.098	--	--	--	--	--	--
Medium Sulfur Bituminous (BE)	0.028	0.028	0.028	0.214	0.214	0.214	0.036	0.036	0.036	0.072	0.028	0.102	0.072	0.072	0.072	0.085	0.075	0.096	0.092	0.092	0.092
High Sulfur Bituminous (BG)	0.059	0.059	0.059	0.092	0.092	0.092	0.079	0.028	0.113	--	--	--	--	--	--	0.051	0.051	0.051	0.045	0.018	0.071
High Sulfur Bituminous (BH)	0.103	0.103	0.103	0.046	0.046	0.046	0.039	0.019	0.053	0.058	0.058	0.058	0.148	0.148	0.148	--	--	--	--	--	--
Low Sulfur Subbituminous (SA)	0.008	0.007	0.009	0.010	0.010	0.010	0.010	0.010	0.010	--	--	--	--	--	--	--	--	--	--	--	--
Low Sulfur Subbituminous (SB)	0.007	0.007	0.007	--	--	--	0.014	0.014	0.014	0.009	0.009	0.009	0.013	0.012	0.013	--	--	--	--	--	--
Low Medium Sulfur Subbituminous (SD)	0.007	0.006	0.008	0.007	0.007	0.007	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Medium Sulfur Subbituminous (SE)	0.008	0.008	0.008	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Low Medium Sulfur Lignite (LD)	0.014	0.014	0.014	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Medium Sulfur Lignite (LE)	0.014	0.014	0.014	0.019	0.019	0.019	0.018	0.018	0.018	0.020	0.020	0.020	--	--	--	--	--	--	--	--	--
High Sulfur Lignite (LG)	0.036	0.036	0.036	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
High Sulfur Lignite (LH)	0.011	0.011	0.011	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--

Table 7-9 Coal Clustering by Coal Grade – CO_2 Emission Factors (lbs/MMBtu)

Coal Type by Sulfur Grade	CO_2 Emission Factors (lbs/MMBtu)																				
	Cluster #1			Cluster #2			Cluster #3			Cluster #4			Cluster # 5			Cluster # 6			Cluster # 7		
	Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range		Cluster Value	Data Range	
		Low	High		Low	High		Low	High		Low	High		Low	High		Low	High		Low	High
Low Sulfur Bituminous (BA)	209.6	209.6	209.6	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Low Sulfur Bituminous (BB)	206.8	206.4	207.1	210.7	207.1	215.5	210.4	206.4	214.3	208.4	204.7	209.6	206.4	206.4	206.4	--	--	--	--	--	--
Low Medium Sulfur Bituminous (BD)	204.7	204.7	204.7	206.4	206.4	206.4	--	--	--	212.9	209.6	216.1	206.4	206.4	206.4	--	--	--	--	--	--
Medium Sulfur Bituminous (BE)	204.7	204.7	204.7	203.1	203.1	203.1	203.1	203.1	203.1	206.7	204.7	209.6	204.7	204.7	204.7	204.7	204.7	204.7	204.7	204.7	204.7
High Sulfur Bituminous (BG)	204.7	204.7	204.7	204.7	204.7	204.7	203.1	203.1	203.1	--	--	--	--	--	--	202.8	202.8	202.8	204.7	204.7	204.7
High Sulfur Bituminous (BH)	203.1	203.1	203.1	204.7	204.7	204.7	203.6	203.1	204.7	204.7	204.7	204.7	204.7	204.7	204.7	--	--	--	--	--	--
Low Sulfur Subbituminous (SA)	215.7	215.5	216.1	214.3	214.3	214.3	214.3	214.3	214.3	--	--	--	--	--	--	--	--	--	--	--	--
Low Sulfur Subbituminous (SB)	212.8	212.8	212.8	--	--	--	209.2	209.2	209.2	214.3	214.3	214.3	214.9	214.3	215.5	--	--	--	--	--	--
Low Medium Sulfur Subbituminous (SD)	215.1	214.3	215.5	209.2	209.2	209.2	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Medium Sulfur Subbituminous (SE)	209.2	209.2	209.2	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Low Medium Sulfur Lignite (LD)	219.3	219.3	219.3	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
Medium Sulfur Lignite (LE)	216.0	212.6	219.3	219.3	219.3	219.3	217.9	216.5	219.3	212.6	212.6	212.6	--	--	--	--	--	--	--	--	--
High Sulfur Lignite (LG)	212.6	212.6	212.6	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--
High Sulfur Lignite (LH)	212.6	212.6	212.6	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--

7.1.5 Coal Grade Assignments

The grades of coal that may be used by specific generating units were determined by an expert assessment of the ranks of coal that a unit had used in the past, the removal efficiency of the installed FGD, and the SO_2 permit rate of the unit. Examples of the coal grade assignments made for individual plants in EPA 2023 Reference Case are shown in Table 7-10. Not all the coal grades allowed to a plant by the coal grade assignment are necessarily available in the plant's assigned coal demand region (due to transportation limitations). IPM endogenously selects the coal consumed by a plant by considering both the constraint of the plant's coal grade assignment and the constraint of the coals available within a plant's coal demand region.

Table 7-10 Example of Coal Assignments Made in the EPA 2023 Reference Case

Plant Name	Unit	Permit Rate (lbs/MMBtu)	Scrubber?	Fuels Allowed
Mt Storm	3	0.15	Yes	BA, BB, BD
Mitchell	1	1.2	Yes	BA, BB, BD, BE, BG, BH
Scherer	1	1.2	Yes	SA, SB, SD, SE
Limestone	LIM1	0.6	Yes	LD, LE, LG, LH, SA, SB, SD, SE
San Miguel	SM-1	1.2	Yes	LD, LE, LG, LH

7.2 Coal Supply Curves

7.2.1 Nature of Supply Curves Developed for EPA 2023 Reference Case

In keeping with IPM's data-driven bottom-up modeling framework, a bottom-up approach (relying heavily on detailed economic and resource geology data and assessments) was used to prepare the thermal coal supply curves for EPA 2023 Reference Case.[65] EPA utilized Wood Mackenzie to develop the curves based on their extensive experience in preparing mine-by-mine estimates of cash operating costs for operating mines in the U.S., their access to both public and proprietary data sources, and their active updating of the data through research and interviews.

In order to establish consistent nomenclature, Wood Mackenzie first mapped its internal list of coal regions and qualities to EPA's 34 coal supply regions (described above in section 7.1.1) and the 14 coal rank/grade combinations (described above in section 7.1.3). The combined code list is shown in Table 7-11 below, with the IPM coal supply regions appearing in the rows and the coal grades in the columns. Wood Mackenzie then created supply curves for each region and coal-grade combination (indicated by the "x" in Table 7-11) for forecast years 2023, 2025, 2028, 2030, 2035, 2040, 2045, and 2050.

Table 7-11 Basin-Level Groupings Used in Preparing the EPA 2023 Reference Case Coal Supply Curves

			Bituminous						Lignite				Subbituminous			
Coal Supply Region	Geo Region	Geo. Sub-Region	BA	BB	BD	BE	BG	BH	LD	LE	LG	LH	SA	SB	SD	SE
AB	Canada	Alberta, Canada											x	x	x	
AK	Alaska	Alaska											x			
AL	Appalachia	Southern Appalachia		x	x	x										
AZ	West	Southwest		x												

[65] These coal supply curves are initialized for the start year of 2023. Since the first run year in the EPA 2023 Base Case is 2028, the resource base underlying the coal supply curves is depleted for the expected coal produced during the 2023-2027 period. The depletion amount is calculated as five times the coal consumed by the power sector in 2022 per the 2022 EIA Form 923.

			Bituminous						Lignite				Subbituminous			
Coal Supply Region	Geo Region	Geo. Sub-Region	BA	BB	BD	BE	BG	BH	LD	LE	LG	LH	SA	SB	SD	SE
BC	Canada	British Columbia			x											
CG	West	Rocky Mountain		x										x		
CR	West	Rocky Mountain		x												
CU	West	Rocky Mountain		x												
IL	Interior	East Interior (Illinois Basin)				x	x	x								
IN	Interior	East Interior (Illinois Basin)				x	x	x								
KE	Appalachia	Central Appalachia		x	x	x										
KW	Interior	East Interior (Illinois Basin)					x	x								
LA	Interior	Gulf Lignite								x						
MD	Appalachia	Northern Appalachia				x	x									
ME	West	Dakota Lignite								x						
MP	West	Powder River Basin											x		x	
MS	Gulf	Gulf Lignite Coast								x						
MT	West	Western Montana		x												
ND	West	Dakota Lignite								x						
NS	West	Southwest												x	x	x
OH	Appalachia	Northern Appalachia				x	x	x								
OK	West	West Interior					x									
PC	Appalachia	Northern Appalachia				x	x	x								
PW	Appalachia	Northern Appalachia				x	x	x								
SK	Canada	Saskatchewan							x	x						
TN	Appalachia	Central Appalachia		x		x										
TX	Interior	Gulf Lignite								x	x	x				
UT	West	Rocky Mountain	x	x	x	x										
VA	Appalachia	Central Appalachia		x	x	x										
WG	West	Western Wyoming		x										x	x	
WH	West	Powder River Basin											x			
WL	West	Powder River Basin											x	x		
WN	Appalachia	Northern Appalachia				x		x								
WS	Appalachia	Central Appalachia		x	x	x										

7.2.2 Cost Components in the Supply Curves

Costs are represented as total cash costs, which is a combination of a mine's operating cash costs plus royalty & levies. These costs are estimated on a Free on Board (FOB) basis at the point of sale. Capital costs (either expansionary or sustaining) are not included in the cash cost estimate for existing mines. For projects, the expansionary capital is spread across the mine life and included in the costs. The total cash cost is the best metric for the supply curves as coal prices tend to be ultimately determined by the incremental cost of production (i.e., total cash cost).

Operating cash cost

These are the direct operating cash costs and include, where appropriate, mining, coal preparation, product transport, and overheads. No capital cost component or depreciation & amortization charge is included for operating mines. Expansionary capital is included for new greenfield projects. Operating cash costs consist of the following elements:

Mining costs - Mining costs are the direct cost of mining coal and associated waste material for surface and underground operations. It includes any other mine site costs, such as ongoing rehabilitation / reclamation, security, community development costs. It also includes the cost of transporting raw coal from the mining location to the raw coal stockpile at the coal preparation plant.

Coal preparation - The cost of coal preparation includes raw coal stockpile reclaim, crushing and screening, washing and marketable coal product stockpiling (if applicable).

Transport - This covers all transport costs of product coal to point of sale. Transport routes with multiple modes (e.g., truck and rail) are shown as total cost per marketable ton for all stages of the transport route. Loading charges are included in this cost if relevant.

Overheads - This is any non-production related general and administration overheads that are essential to the production and sale of a mine's coal product. Examples would be mine site staff not related to mining, essential corporate management or a sales and marketing charge.

It is important to note that although the formula for calculating mine costs is consistent across regions, some tax rates and fees vary by state and mine type. In general, there are two mine types: underground (deep) or surface mines. Underground mining is categorized as being either a longwall (LW) or a continuous room-and-pillar mine (CM). Geologic conditions and characteristics of the coal seams determine which method will be used. Surface mines are typically categorized by the type of mining equipment used in their operation such as draglines (DL), or truck & shovels (TS). These distinctions are important because the equipment used by the mine affects productivity measures and ultimately mine costs. Further information on operating cost methodology and assumptions can be found in Attachment 7-1.

Royalties and Levies

These include, where appropriate, coal royalties, mine safety levies, health levies, industry research levies and other production taxes. These taxes, fees and levies vary on a regional basis.

7.2.3 Procedures Employed in Determining Mining Costs

The total cash costs of mines have been estimated in current year terms using public domain information including; geological reports, reported statistics on production, labor and input costs, and company reports. The estimates have been validated by reference to information gained by visits to operations, and discussions with industry participants.

Because the estimates are based only on public information and analysis, and do not represent private knowledge of an operation's actual costs, there may be deviations from actual costs. In instances where confidential information is held by Wood Mackenzie, it has not been used to produce the published estimates. Several methods are employed for cost estimation depending on the availability of information and the diversity of mining operations. When possible, Wood Mackenzie analysts developed detailed lists of mine-related costs. Costs such as employee wages & benefits, diesel fuel, spare parts, roof bolts, and explosives among a host of others are summed to form a mine's operating cash costs.

Where information is incomplete, cost items are grouped into categories that can be compared with industry averages by mine type and location. These averages can be adjusted up or down based on new information or added assumptions. The adjustments take the form of cost multipliers or parameter values. Specific cost multipliers are developed with the aid of industry experts and proprietary formulas. This method is at times used to convert materials and supplies, on-site trucking costs and mine and division overhead categories into unit removal costs by equipment type. To check the accuracy of these cost estimates, cash flow analysis of publicly traded companies is used. Mine cash-costs are extracted from corporate cash flows and compared with the initial estimates. Adjustments for discrepancies are made on a case-by-case basis.

Many of the cost assumptions associated with labor and productivity were taken from the Mine Safety Health Administration (MSHA) database. All active mines report information specific to production levels, number of employees and employee hours worked. Wood Mackenzie supplements the basic MSHA data with information obtained from mine personnel interviews and industry contacts. Phone conversations and conferences with industry professionals provide additional non-reported information such as work schedules, equipment types, percentages of washed coal, and trucking distances from the mine to wash-plants and load-out terminals.

For each active or proposed mine, Wood Mackenzie reports the estimated cost to take coal from the mine to a logical point-of-sale. The logical point-of-sale may be a truck or railcar load-out or even a barge facility. This is done to produce a consistent cost comparison between mines. Any transport costs beyond the point-of-sale terminal are not part of this analysis and are not reflected in the supply curves themselves.

7.2.4 Procedure Used in Determining Mine Productivity

Projected production and stripping ratios are the key determinants of surface mine productivity. Wood Mackenzie assumes mining costs increase as stripping ratios increase. The stripping ratio is the quantity of overburden removed relative to the quantity of coal recovered. Assuming that reserves are developed where they are easiest to mine and deliver to market, general theory suggests that as the easy reserves are depleted, greater amounts of overburden must be handled for the same amount of coal production; thus causing a decrease in mining productivity. However, some productivity loss may be offset by technological improvements in labor saving equipment.

In order to calculate the amount of employee hours, and therefore the labor cost, of future production Wood Mackenzie uses a multi-step process. First, employee hours associated with coal production for each mine are obtained from MSHA. Total production is then divided by these hours to calculate productivity, measured in short tons per employee hour. Future production levels are divided by this productivity measurement to obtain future employee hours needed to produce that volume of coal. From there, the total staffing level can be determined, and the associated cost calculated.

A similar approach is used for underground mines. First, as background, the specific factors affecting productivity at such mines are identified. For example, underground mines do not have stripping ratios. Productivity estimates for these mines largely depend on the type of mining technique used (which is a function of the region’s geology). For instance, longwall-mines can produce a high volume of low-cost coal but geologic constraints like small reserve blocks and the occurrence of faulting tends to limit this technique to certain regions. In addition to geologic constraints, there are variables that can impact underground-mine productivity that are often difficult to quantify and forecast.

7.2.5 Procedure to Determine Total Recoverable Reserves by Region and Type

Before mine operators are allowed to mine coal, they must request various permits, conduct environmental impact studies (EIS) and, in many cases, notify corporate shareholders. In each of these instances, mine operators are asked to estimate annual production and total recoverable reserves. Wood

Mackenzie uses the mine operators' statements as the starting point for production and reserves forecasts. If no other material is available, interviews with company personnel will provide an estimate.

Region and coal type determinations for unlisted reserves are based on public information reported for similarly located mines. Classifying reserves this way means considering not only a mine's geographic location but also its geologic conditions such as depth and type of overburden and the specific identity of the coal seam(s) being mined. For areas where public information is not available or is incomplete, Wood Mackenzie engineers and geologists estimate reserve amounts based on land surveys and reports of coal depth and seam thickness provided by the U.S. Geologic Service (USGS). This information is then used to extrapolate reserve estimates from known coal sources to unknown sources. Coal quality determinations for unknown reserves are assigned in much the same way.

Once a mine becomes active, actual production numbers reported in corporate SEC filings and MSHA reports are subtracted from the total reserve number to arrive at current reserve amounts. Wood Mackenzie consistently updates the reserves database when announcements of new or amended reserves are made public. As a final check, the Wood Mackenzie supply estimates are balanced against the Demonstrated Reserve Base (DRB)[66] estimates to ensure that they do not exceed the DRB estimates.

7.2.6 New Mine Assumptions

New mines have been included based on information that Wood Mackenzie maintains on each supply region. They include announced projects, coal lease applications and unassigned reserves reported by mining companies. Where additional reserves are known to exist, additional incremental steps have been added and designated with the letter "N" in the "Step Name" field of the supply curves. These incremental steps were added based on characteristics of the specific region, typical mine size, and cost trends. They do not necessarily imply a specific mine or mine type.

Wood Mackenzie has also identified technical coal reserves that may be commercial in the longer-term, but would most likely not be developed until after the completion of mine development already underway or announced. These reserves are often the "last step" in a coal supply curve due to the more difficult geologic conditions and have been designated using the above methodology.

In addition to new mines, Wood Mackenzie also identifies extension mines. These are denoted with the letter "A", "B", "C" or "D" at the end of an existing mine step name (e.g., E2A). These mine steps reflect the extension of a particular mine operating through a new lease covering tracts not previously recoverable under the existing mine operation. These mine expansions, like new mines, include the capital expansionary component in their cost of production.

7.2.7 Other Notable Procedures

<u>Currency Assumptions</u>

For consistency with the cost basis used in EPA 2023 Reference Case, costs are converted to real 2019$.

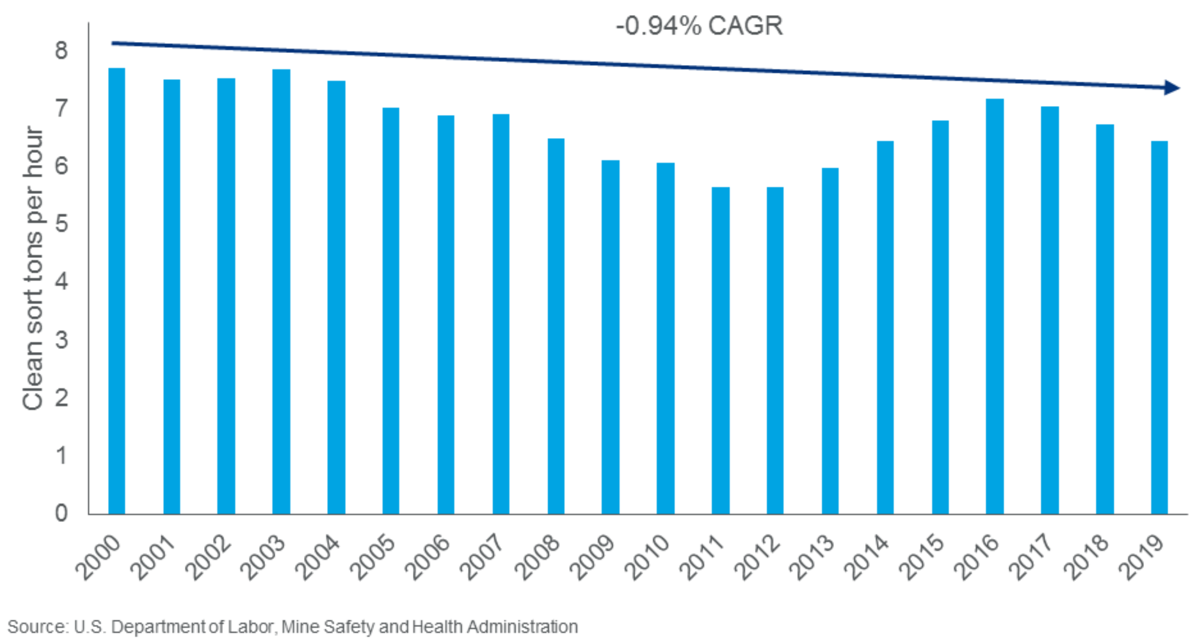
<u>Future Cost Adjustments</u>

Changes in mine productivity are a key factor impacting the evolution of costs over time. In general, mine productivity is expected to continue to decline – in large part due to worsening geology and more difficult

[66] Posted by the Energy Information Administration (EIA) in its Coal Production Report.

to mine reserves. Productivity has declined at a -0.94% compound annual growth rate (CAGR) from 2000-2019 as shown in Figure 7-2.

Figure 7-2 Coal Mine Productivity (2000-2019)



Source: U.S. Department of Labor, Mine Safety and Health Administration

Figure 7-3 Average Annual Cost Growth Assumptions by Region (2021-2050)

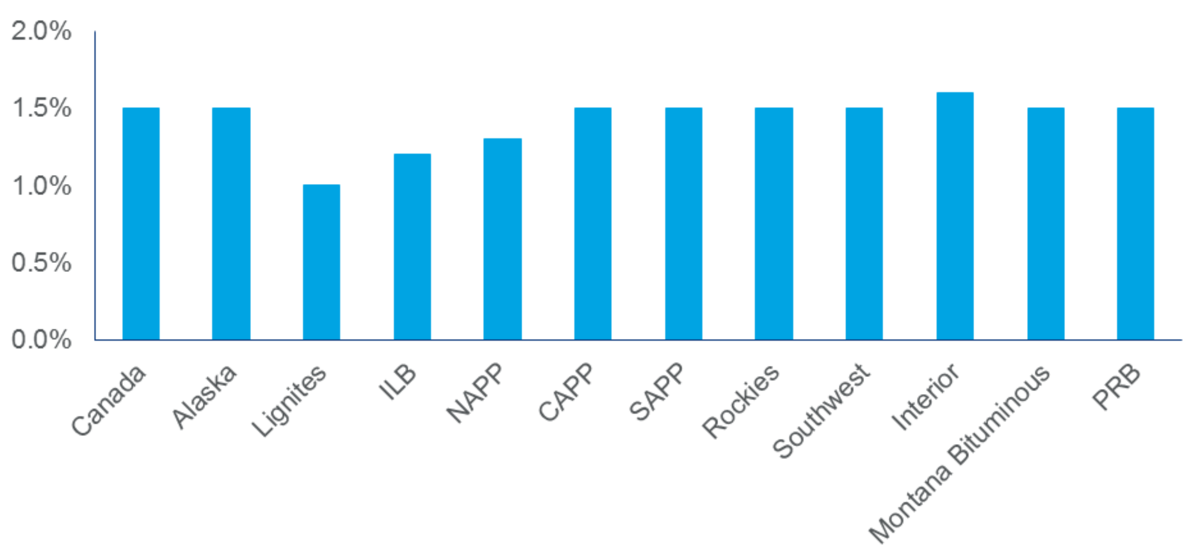


Figure 7-3 shows the compounded average annual growth rate (CAGR) of mining costs by basin over the forecast period. It should be noted that cost increases would ultimately be linked to market demand (as demand grows, the faster the rate of depletion of lower cost reserves). Costs in some supply basins are expected to increase more quickly than others due to issues such as mining conditions, productivity, infrastructure limitations, etc. Region-specific information can be found in section 7.2.9.

Supply Growth Limitations

To the maximum extent possible, the IPM model is set up to determine the optimal volume of coal supply which can be profitably supplied. For two of the lower-cost basins (Powder River and Illinois basins), maximum production capacities are included as constraints (production ceilings) to reflect more accurately the upper bound of what could be produced in a given year. Those limits, represented in millions of tons per year, are shown in Figure 7-4. While not binding in EPA's reference case, these ceilings are necessary to guard against modeling excess annual production capacity in certain basins under sensitivity scenarios. For instance, in the PRB, several of the "new" mines reflect expansion mines that would not be developed until the initial mine is further depleted. In this case, the production ceiling helps safeguard against a modeling scenario that would simultaneously produce from both of these mines.

Figure 7-4 Maximum Annual Coal Production Capacity per Year (Million Short Tons)

	2023	2025	2028	2030	2035	2040	2045	2050
ILB	200	220	240	240	240	240	240	240
PRB	500	520	560	560	600	600	600	600

7.2.8 Cumulative Supply Curve Development

The description below describes the depicts the cumulative supply curve. Table 7-26 shows the actual coal supply curves.

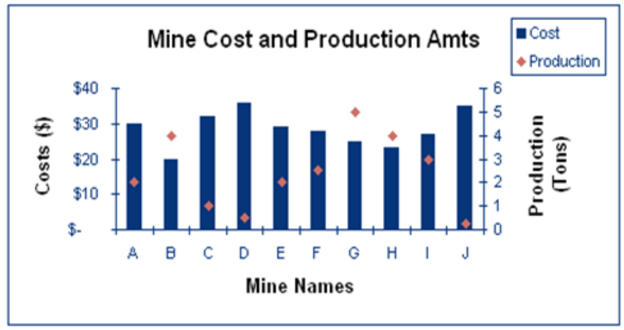
Once costs are estimated for all new or existing mines, they are sorted by cash cost, lowest to highest, and plotted cumulatively by production to form a supply curve. The supply curve then represents all mines – new or existing as well as both underground and surface mines– irrespective of market demand. Mines located toward the bottom of the curve have the lowest cost and are most likely to be developed while the mines at the top of the curve are higher cost and will likely wait to be developed. The process for developing a cumulative supply curve is illustrated in Figure 7-5 and Figure 7-6.

Figure 7-5 Illustration of Preliminary Step in Developing a Cumulative Coal Supply Curve

Key

E = EXISTING MINE
N = NEW MINE
U = UNDERGROUND MINE
S = SURFACE MINE

New or Existing?	Mine	Type	Cost	Production
N	A	S	$ 30	2
E	B	U	$ 20	4
N	C	S	$ 32	1
N	D	S	$ 36	0.5
E	E	S	$ 29	2
N	F	S	$ 28	2.5
E	G	U	$ 25	5
E	H	U	$ 23	4
E	I	U	$ 27	3
N	J	S	$ 35	0.25



In the table and graph above, mine costs and production are sorted alphabetically by mine name. To develop a supply curve from the above table, the values must be sorted by mine costs from lowest to highest. A new column for cumulative production is added, and then a supply curve graph is created, which shows the costs on the 'Y' axis and the cumulative production on the 'X' axis. Notice below that the curve contains all mines – new or existing as well as underground and surface mines. The resulting curve is a continuous supply curve but can be modified to show costs as a stepped supply curve. (Supply curves in stepped format are used in linear programming models like IPM.) See Figure 7-7 for a stepped version of the supply curve example shown in Figure 7-6. Here, each step represents an individual mine, the width of the step reflects the mine's production, and its height shows the cost of production.

Figure 7-6 Illustration of Final Step in Developing a Cumulative Coal Supply Curve

New or Existing?	Mine	Type	Cost	Production	Cum Productio
E	B	U	$ 20	4	4
E	H	U	$ 23	4	8
E	G	U	$ 25	5	13
E	I	U	$ 27	3	16
N	F	S	$ 28	2.5	18.5
E	E	S	$ 29	2	20.5
N	A	S	$ 30	2	22.5
N	C	S	$ 32	1	23.5
N	J	S	$ 35	0.25	23.75
N	D	S	$ 36	0.5	24.25

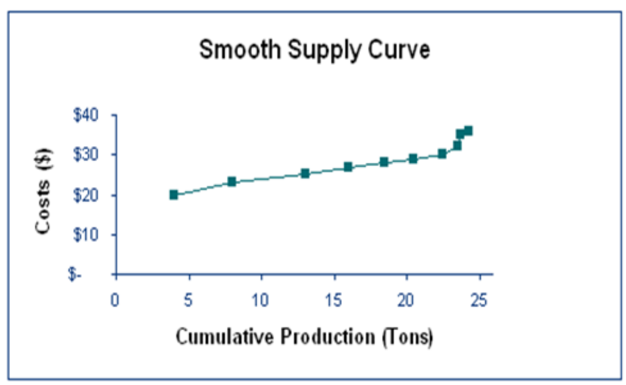
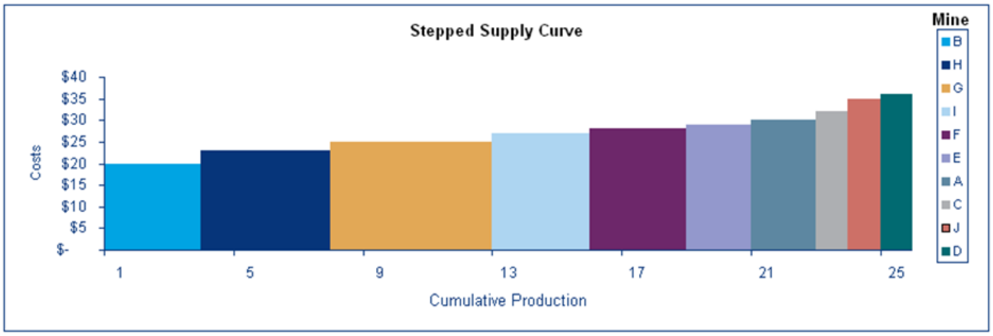


Figure 7-7 Example Coal Supply Curve in Stepped Format



PRODUCTION AMOUNT

Production Scalar

MINE NAME →		B	H	G	I	F	E	A	C	J	D
New or Existing		4	8	13	16	18.5	20.5	22.5	24	25	25.5
E	1	$ 20	-	-	-	-	-	-	-	-	-
E	2	$ 20	-	-	-	-	-	-	-	-	-
E	3	$ 20	-	-	-	-	-	-	-	-	-
E	4	-	$ 23	-	-	-	-	-	-	-	-
E	5	-	$ 23	-	-	-	-	-	-	-	-
E	6	-	$ 23	-	-	-	-	-	-	-	-
E	7	-	$ 23	-	-	-	-	-	-	-	-
E	8	-	-	$ 25	-	-	-	-	-	-	-
E	9	-	-	$ 25	-	-	-	-	-	-	-
E	10	-	-	$ 25	-	-	-	-	-	-	-
E	11	-	-	$ 25	-	-	-	-	-	-	-
E	12	-	-	$ 25	-	-	-	-	-	-	-
E	13	-	-	-	$ 27	-	-	-	-	-	-
E	14	-	-	-	$ 27	-	-	-	-	-	-
E	15	-	-	-	$ 27	-	-	-	-	-	-
N	16	-	-	-	-	$ 28	-	-	-	-	-
N	17	-	-	-	-	$ 28	-	-	-	-	-
N	18	-	-	-	-	$ 28	-	-	-	-	-
E	19	-	-	-	-	-	$ 29	-	-	-	-
E	20	-	-	-	-	-	$ 29	-	-	-	-
N	21	-	-	-	-	-	-	$ 30	-	-	-
N	22	-	-	-	-	-	-	$ 30	-	-	-
N	23	-	-	-	-	-	-	-	$ 32	-	-
N	24	-	-	-	-	-	-	-	-	$ 35	-
N	25	-	-	-	-	-	-	-	-	-	$ 36

7.2.9 EPA 2023 Reference Case Assumptions and Outlooks for Major Supply Basins

Powder River Basin (PRB)

The PRB is somewhat unique to other U.S. coal basins in that producers are able to adjust production volumes relatively easily. That said, the decisions on production volumes are largely based on the market conditions, namely the price. For instance, in a low-demand environment, producers tend to moderate production volumes to maintain attractive prices and choose to ramp up production when prices are higher. The evolution of costs in the PRB will be strongly correlated to the rate at which producers ramp up production at existing mines, which, as indicated, will depend on market conditions.

Wood Mackenzie anticipates productivity at most existing PRB mining operations to decline at very modest rates over the forecast horizon, with increasing strip ratios at least partly offset by improved usage of labor and capital. As most PRB mines progress downward, the overburden to coal (strip ratios) will increase in the future. The productivity of new mines will be quite low during the early stages of their life span.

Mining at several locations is steadily proceeding westward toward the Joint Line railroad, and, at current and forecasted levels of production, around 2023, several mines are expected to eventually reach the line. This event will result in a costly movement across the railroad, requiring significant capital investment and reduced production as the transition is made. During the move across the Joint Line railroad, strip ratios will spike, and productivity will fall as new box cuts are created.

Illinois Basin (ILB)

Production costs in the Illinois basin have been mostly flat, with a slight downward trend in recent years as higher-cost mines close and newer low-cost longwall mines maximize their economies of scale. Development of these longwalls has been delayed as natural gas prices largely remain below competitive levels. New developments will be delayed until prices and demand recover. In the long term, the shape of the ILB supply curve has the potential to increase production capacity and decrease costs. However, this is not due to lowering costs at existing mines. Rather, it is caused by new mines coming online that have lower operating costs than existing mines.

The ILB has vast reserves and potential for large-scale, low-cost mine development. However, a shrinking customer base will pose a risk to the basin's growth potential as demand could shrink in the long term.

Central Appalachia (CAPP)

Geologic conditions in the CAPP region are challenging, with thin seams and few underground reserves amenable to more efficient longwall mining techniques. Costs of production in CAPP rose substantially in the early 2010s as the region struggled with mining thinner seams depleting reserves. Mining accidents led to increased inspections, and mine permitting has become increasingly difficult.

Producers cut back production significantly in the years prior to 2017 as coal prices plummeted. Many companies went bankrupt and closed a large proportion of mines. As a result, average costs fell substantially as high-cost, low-productivity mines were closed. In an effort to retain margins, producers implemented a variety of tactics at continuing operations to try to keep production costs from continuing to increase, including shifting more production to lower cost operations and selling lesser quality raw coal to save on coal preparation/washing costs. In the long term, costs will remain mostly flat as cost optimization efforts continue within the highly competitive basin.

Northern Appalachia (NAPP)

Similar to CAPP, mining costs in NAPP have remained mostly flat since the closure of high-cost capacity drove costs downwards. Future mine costs in Northern Appalachia will depend largely on the development of new reserve areas. However, few thermal projects have been identified – meaning located at an existing mine or a named project. The remainder are reserves that are available for development in the region but no engineering or permitting work has begun.

7.3 Coal Transportation

Table 7-25 presents the coal transportation matrix.

Within the United States, steam coal for use in coal-fired power plants is shipped via a variety of transportation modes, including rail, barge, truck, conveyor belt, and lake/ocean vessel. A given coal-fired power plant typically has access to only a few of these transportation options and, in some cases, has access to only a single option. The number of transportation options that a plant has when soliciting coal deliveries influences transportation rate levels that plant owners are able to negotiate with transportation providers.

Within the Eastern United States, rail service is provided predominately by two major rail carriers in the region, Norfolk Southern (NS) and CSX Transportation (CSX). Within the Western United States, rail service is provided predominately by two major rail carriers, Burlington Northern Santa Fe (BNSF) and Union Pacific (UP). Plants in the Midwestern United States may have access to rail service from BNSF, CSX, NS, UP, the Canadian National (CN), Canadian Pacific (CP), or short-line railroads. Barge, truck, and vessel service is provided by multiple firms, and conveyor service is only applicable to coal-fired plants located next to mining operations (e.g., mine-mouth plants).

Between 2016 (when the coal transportation rate assumptions for EPA Platform v6 November 2018 Reference Case were finalized), and 2020, coal production in the United States declined by approximately 192 million tons/year, or 26% (from 728 million tons in 2016 to an estimated 536 million tons in 2020.)[67] Approximately 48 gigawatts of coal-fired generating capacity (or about 18% of the total coal-fired generating capacity in the United States) were retired in the period between the end of 2016 and the end of September 2020.[68]

Transportation rate levels for most coal movements declined significantly in real terms between 2016 and 2020, as sustained low prices for natural gas and major expansions in renewable generation during this period reduced the coal volumes used for electric generation further below the already low levels experienced in 2016. However, since natural gas prices were very low throughout the 2016-2020 period (averaging $2.65/MMBtu in nominal dollars between January 2016 and November 2020 at Henry Hub).[69] the decline in coal transportation rates between 2016 and 2020 was not sufficient to make coal-fired generation price-competitive with natural gas-fired generation in most areas of the U.S. Instead, the 2020 coal transportation rates shown in this analysis represent strategic decisions by the railroads and other providers of coal transportation to preserve as much contribution margin as possible on the remaining coal traffic (while accepting volume declines viewed as largely unavoidable) rather than competing aggressively for incremental coal volumes. Rail rates for short-distance coal movements to captive plants either stayed the same or increased in real terms between 2016-2020, as the railroads sought to partially offset nationwide declines in coal volumes at the small subset of plants where they have the most market power.

In this market environment, in which the railroads and other providers of coal transportation are generally seeking to extract the maximum margins from coal traffic which is expected to steadily decline in volume over the long term, any future arrangements tying coal transportation rates to natural gas pricing would likely have to be very limited and site-specific (as was already the case in 2016.)

During 2021-2050, rates for most modes of coal transportation are expected to be flat to decline in real dollars from the 2020 levels, reflecting relatively low levels of expected coal demand throughout the forecast period used in EPA 2023 Reference Case.

The transportation methodology and rates presented below reflect expected long-run equilibrium transportation rates as of August 2020, when the coal transportation rate assumptions for EPA 2023 Reference Case were finalized. The forecasted changes in transportation rates during the 2021-2050 forecast period reflect expected changes in long-term equilibrium transportation rate levels, including the long-term market dynamics that will drive these pricing levels.

All the transportation rates discussed in this document are expected 2020 rates and are shown in 2019 real dollars.

7.3.1 Coal Transportation Matrix Overview

Description

The general structure of the coal transportation matrix in EPA 2023 Reference Case is similar to the structure used in EPA Platform v6 November 2018 Reference Case. Each coal-fired power plant included

[67] The coal production data cited here is U.S. Energy Information Administration (EIA) data. 2016-2019 data is from the quarterly coal report released October 2020, is available at https://www.eia.gov/coal/production/quarterly/. 2020 data is estimated based on a 24.1% decline from 2019 coal production levels for 2020 year-to-date through 12/12/2020, as shown in EIA's Weekly Coal Production data (available at https://www.eia.gov/coal/production/weekly/).

[68] Data from EIA Electric Power Monthly, February 2017, and November 2020 releases, available at https://www.eia.gov/electricity/monthly/.

[69] EIA data available at: https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm

in the EPA 2023 Reference Case is individually represented in the coal transportation matrix. This allows the coal transportation routings, coal transportation distances, and coal transportation rates associated with each individual coal-fired generating plant to be estimated on a plant-specific basis. The coal transportation matrix shows the total rate to transport coal from selected coal supply regions to each individual coal-fired generating plant.

The coal supply regions associated with each coal-fired generating plant in EPA 2023 Reference Case are largely unchanged from the previous version of EPA Platform v6. The coal supply regions associated with each coal-fired power plant are the coal supply regions that were supplying each plant as of the first half of 2020, have supplied each plant in previous years, or are considered economically and operationally feasible sources of additional coal supply during the forecast period in EPA 2023 Reference Case. A more detailed discussion of the coal supply regions can be found in previous sections.

<u>Methodology</u>

Each coal supply region and coal-fired power plant is connected via a transportation link, which can include multiple transportation modes. For each transportation link, cost estimates, in terms of $/ton, were calculated utilizing mode-based transportation cost factors, analysis of the competitive nature of the moves, and overall distance that the coal type must move over each applicable mode. An example of the calculation methodology for movements including multiple transportation modes is shown in Figure 7-8.

Figure 7-8 Calculation of Multi-Mode Transportation Costs (Example)

Rail Cost ($/ton) = Rail Mill Rate (mills/ton-mile) x Rail Mileage + Transloading Cost ($/ton) + Barge Cost ($/ton) = Loading Cost ($/ton) + Barge Mill Rate (mills/ton-mile) x Barge Mileage

Calculation of Coal Transportation Distances

<u>Definition of applicable supply/demand regions</u>

Coal-fired power plants are linked to coal supply regions based on historical coal deliveries, as well as based on the potential for new coal supplies to serve each coal-fired generating plant going forward. A generating plant will usually have transportation links with more than one supply region, depending on the various coal types that can be physically delivered and burned at that particular plant. On average, each coal-fired generating plant represented in IPM is linked with about eight coal supply regions. Some plants may have more than the average number of transportation links, and some may have fewer, depending on the location of each plant, the transportation modes available to deliver coal to each plant, the boiler design and emissions control technologies associated with each plant, and other factors that affect the types of coal that can be burned at each plant.

For mine-mouth plants (plants for which the current coal supply is delivered from a single nearby mine, generally by conveyor belt or using truck transportation) that are 200 MW or larger, Hellerworx has estimated the cost of constructing facilities that would allow rail delivery of alternative coal supplies, and the transportation rates associated with the delivery of alternative coal supplies. This includes the construction of rail spurs (between one and nine miles in length depending on the proximity of each plant to existing railroad lines) to connect each plant with existing railroad lines.

Transportation Links for Existing Coal-Fired Plants

Transportation routings from particular coal supply regions to particular coal-fired power plants were developed based on third-party software[70] and other industry knowledge available to Hellerworx. Origins for each coal supply region were based on significant mines or other significant delivery points within the supply region, and the destination points were plant-specific for each coal-fired generating plant represented in IPM. For routes utilizing multiple modes (e.g., rail-to-barge, truck-to-rail, etc.), distances were developed separately for each transportation mode.

Transportation Links for New Coal-Fired Plants

Representative coal transportation costs for new coal-fired power plants not yet under construction (i.e., coal transportation costs for a new coal-fired power plant modeled by IPM) were estimated by selecting an existing coal-fired power plant within each IPM Region whose coal supply alternatives and coal transportation costs, were considered representative of the coal supply alternatives and coal transportation costs that would likely be faced by new coal-fired power plants within that same IPM Region. In cases where there are no existing coal plants within a particular IPM Region, the coal supply alternatives and coal transportation costs applicable to that IPM Region were estimated using a methodology similar to that used for the existing coal plants.[71] Using this consistent methodology across all of the IPM regions helps ensure that coal transportation costs for new coal plants are properly integrated with and assessed fairly vis-à-vis existing coal-fired assets within the IPM modeling structure.

7.3.2 Overview of Rail Rates

Competition within the railroad industry is limited. Two major railroads in the Western U.S. (BNSF and UP) and two major railroads in the Eastern U.S. (CSX and NS) currently originate most of the U.S. coal traffic that moves by rail.

As noted earlier in this section, rail rates for most coal movements declined significantly during 2016-2020, and coal demand for electric generation declined significantly as well. Continued strong competition from natural gas-fired generation and renewables over the duration of the forecast period used in the EPA 2023 Reference Case is expected to limit future coal demand and lead to further real declines in rail rates over the long term.

The differential between rail rates at captive plants and rates at competitively served plants widened slightly during 2016-2020 due to flat or increasing rates at the relatively small subset of coal-fired generating plants where the railroads still have significant market power (short-distance movements to captive plants).

Since August 2016, the Surface Transportation Board (“STB”) has been engaged in a process (STB Ex Part 665, Sub. No. 2, Expanding Access to Rate Relief) designed to make it easier for small shippers to obtain rail rate relief from the STB. On September 11, 2019, the Board issued a Notice of Proposed Rulemaking (NPRM), proposing to adopt Final Offer Rate Review as a rate-setting mechanism. This would be far cheaper and faster than the SAC approach. While designed for small rate cases, it is obvious that the STB is searching for a means of making rate relief more widely available to shippers. Whether this will be adopted, and if adopted withstand legal challenge is unknown, but the STB will likely continue to seek ways to make its regulatory authority feasible for shippers to use. It is also unclear if shippers would spend much to engage in a risky process to try and reduce rail rates to a coal-fired power plant with limited future prospects.

[70] Rail routing and mileage calculations utilize ALK Technologies PC*Miler software.

[71] Since the Canadian government has phased out coal-fired generation in Ontario, and in late 2016 announced plans to phase out coal-fired generation in Alberta by 2030, coal-fired generation was not modeled in the Canadian provinces where it is not currently used.

However, it is unlikely that any new regulatory mechanisms will have a widespread impact on coal rates. Under the legislation that currently governs rail rate relief (the Staggers Act, passed in 1980), the STB is statutorily prohibited from mandating rates that are less than 180% of long-run variable costs (LRVC). Very few rail rates for coal are set above this level (with the possible exception of some short-distance movements to captive plants, which are a small segment of the total coal traffic.) Competition from natural gas-fired generation has caused many high-cost coal plants to be shut down. Any future regulations relating to greenhouse gas emissions would also add to coal's costs relative to all other fuel sources. In summary, the market trends described throughout this analysis are likely to have much greater impacts on rail rates for coal transportation than any future changes in the regulatory scheme.

All the rail rates discussed below include railcar costs and fuel surcharges at expected 2020 fuel price levels. When the rail rate assumptions used in EPA 2023 Reference Case were finalized in August 2020, the latest Form EIA-923 data that was available for the analysis of historical delivered coal prices and rail rates was data through May 2020. Therefore, almost all the data that was relied upon to estimate the trends in historical rail rates between 2016 and early 2020 reflects rail contracts that would have been negotiated before the beginning of the COVID-19 lockdowns in the United States (i.e., before mid-March 2020.) The forward-looking portion of the rail rate analysis (2021-2050) also focused on the expected long-term trends within the coal and rail industries over the entirety of this 30-year period rather than on short-term disruptions related to COVID-19. Thus, neither the 2020 rail rate estimates nor the forecast of expected long-term trends in rail rates should be biased by any short-term disruptions related to COVID-19.

Overview of Rail Competition Definitions

Within the transportation matrix, rail rates are classified as being either captive or competitive (see Table 7-12) depending on the ability of a given coal demand region to solicit supplies from multiple suppliers. Competitive rail rates are further subdivided into high- and low-cost competitive subcategories. Competition levels are affected both by the ability to take delivery of coal supplies from multiple rail carriers, and the use of multiple rail carriers to deliver coal from a single source (e.g., BNSF/UP transfer to NS/CSX for PRB coal moving east), or the option to take delivery of coal via alternative transportation modes (e.g., barge, truck, or vessel).

Table 7-12 Rail Competition Definitions

Competition Type	Definition
Captive	Demand source can only access coal supplies through a single provider; demand source has limited power when negotiating rates with railroads.
High-Cost Competitive	Demand source has some, albeit still limited, negotiating power with rail providers; definition typically applies to demand sources that have the option of taking delivery from either of the two major railroads in the region.
Low-Cost Competitive	Demand source has a strong position when negotiating with railroads; typically, these demand sources also have the option of taking coal supplies via modes other than rail (e.g., barge, truck, or lake/ocean vessel).

Rail Rates

As previously discussed, rail rates are subdivided into three competitive categories: captive, high-cost competitive, and low-cost competitive. Moves are further subdivided based on the distance the coal supply must move over rail lines: <200 miles, 200-299 miles, 300-399 miles, 400-649 miles, and 650+ miles. Within the Western U.S., mileages are only subdivided into two categories (<300 miles and 300+ miles), given the longer distances that these coal supplies typically move.

Initial rate level assumptions were determined based on an analysis of recent rate movements, current rate levels in relation to maximum limits prescribed by the STB, expected coal demand, diesel prices, recent capital expenditures by railroads, and projected productivity improvements. In general, shorter moves result in higher applicable rail rates due to the lesser distance over which fixed costs can be spread. As previously discussed, rail rates reflect anticipated 2020 costs in 2019 real dollars.

Rates Applicable to Eastern Moves

Rail movements within the Eastern U.S. are handled predominately by the region's two major carriers, NS and CSX. Some short movements are handled by a variety of short-line railroads. Most plants in the Eastern U.S. are served solely by a single railroad (i.e., they are captive plants). The practical effect of this is that CSX and NS do not compete aggressively at the limited number of plants that have access to both major railroads, and the rates for high-cost competitive plants tend to be similar to the rates for captive plants. Table 7-13 presents the 2020 eastern rail rates.

Table 7-13 Assumed Eastern Rail Rates for 2020 (2019 mills/ton-mile)

Mileage Block	Captive	High-Cost Competitive	Low-Cost Competitive
< 200	122	122	104
200-299	71	71	60
300-399	57	57	48
400-649	53	53	45
650+	33	33	28

Prior to the EPA Platform v6 November 2018 Reference Case update in 2016, CSX introduced a new structure for some of its rail contracts that includes both fixed and variable components. This was an attempt to help coal-fired generating plants located on the CSX system compete more effectively with natural gas-fired generation by offering the generators the opportunity to include only the variable cost component in their dispatching costs.

However, many larger generators (whose systems included both CSX-served plants, and plants served by NS or other transportation providers) felt that this contracting structure might tend to favor CSX-served plants at the expense of other plants on their own systems, and/or unnecessarily complicate dispatching. Therefore, use of the contracting structure that includes fixed and variable rail rate components was discontinued in EPA 2023 Reference Case. This change will have a very limited effect on the IPM modeling for coal-fired generating plants since this contracting structure was experimental and was only used at a limited number of plants in EPA Platform v6 November 2018 Reference Case.

Rates Applicable to Midwestern Moves

Plants in the Midwestern U.S. may be served by BNSF, CN, CP, CSX, NS, UP or short-line railroads. However, the rail network in the Midwestern U.S. is very complex, and most plants are served by only one of these railroads. The Midwestern U.S. also includes a higher proportion of barge-served and truck-served plants than is the case in the Eastern or Western U.S. Table 7-14 depicts 2020 rail rates in the Midwest.

Table 7-14 Assumed Midwestern Rail Rates for 2020 (2019 mills/ton-mile)

Mileage Block	Captive	High-Cost Competitive	Low-Cost Competitive
< 200	122	122	104
200-299	80	80	68
300-399	57	57	48
400-649	57	57	48
650+	33	33	28

Rates Applicable to Western Moves

Rail moves within the Western U.S. are handled predominately by BNSF and UP. Rates for Western coal shipments from the PRB are forecast separately from rates for Western coal shipments from regions other than the PRB. This reflects the fact that in many cases coal shipments from the PRB are subject to competition between BNSF and UP, while rail movements of Western coal from regions other than the PRB consist primarily of Colorado and Utah coal shipments that originate on UP, and New Mexico coal shipments that originate on BNSF. PRB coal shipments also typically involve longer trains moving over longer average distances than coal shipments from the other Western U.S. coal supply regions, which means these shipments typically have lower costs per ton-mile than non-PRB coal shipments. In the west, there are enough plants that have access to both BNSF and UP or a neutral carrier that the western railroads are concerned with losing coal volume to the competing railroad and therefore offer more of a rate discount to plants that can access both railroads (e.g., high-cost competitive).

Prior to the EPA Platform v6 November 2018 Reference Case update in 2016, BNSF offered temporary spot rail rate discounts to a few selected generating plants using PRB coal to improve the utilization of these plants during periods of unusually lower natural gas prices. However, since Hellerworx believes that these discounts were only offered experimentally and temporarily to a few captive generating plants using PRB coal in the Gulf Coast region, they were not modeled in EPA Platform v6 November 2018 Reference Case. The sustained low prices for natural gas during 2016-2020 appear to have made both BNSF and UP even more reluctant to tie their rail rates to natural gas prices as of 2020 than they were in 2016. Therefore, the rail rate discounts related to natural gas pricing were also not modeled in EPA 2023 Reference Case.

Over the forecast period, coal volumes are likely to continue to decline significantly from the 2020 levels in most forecast scenarios. Therefore, other commodities, such as intermodal traffic and oil which have greater growth potential than coal, are likely to become even more important strategically to the railroads in the future than they are in 2020, and the railroads are expected to be generally unwilling to offer large discounts from their base rates to compete for incremental coal volumes throughout the forecast period.

Non-PRB Coal Moves

The assumed non-PRB western rail rates for 2020 are shown in Table 7-15.

Table 7-15 Assumed Non-PRB Western Rail Rates for 2020 (2019 mills/ton-mile)

Mileage Block	Captive	High-Cost Competitive	Low-Cost Competitive
< 300	69	32	32
300+	40	28	28

The assumed PRB western rail rates for 2020 are available in Table 7-16.

PRB Moves Confined to BNSF/UP Rail Lines

Table 7-16 Assumed PRB Western Rail Rates for 2020 (2019 mills/ton-mile)

Mileage Block	Captive	High-Cost Competitive	Low-Cost Competitive
< 300	46	19	19
300+	21	15	15

PRB Moves Transferring to Eastern Railroads

For PRB coal moving west-to-east, the coal transportation matrix assumes that the applicable low-cost competitive assumption is applied to the BNSF/UP portion of the rail mileage, and an assumption of either $2.30 per ton or 28 mills per ton-mile (whichever is higher) is applied to the portion of the movement that occurs on railroads other than BNSF and UP. (The $2.30 per ton assumption is a minimum rate for short-distance movements of PRB coal on Eastern railroads.)

7.3.3 Truck Rates

Truck rates include loading and transport components, and all trucking flows are considered competitive because highway access is open to any trucking firm. The truck rates shown in Table 7-17 are expected 2020 rate levels, in 2019 dollars. The lower truck rates in EPA 2023 Reference Case (as compared to EPA Platform v6 November 2018), reflect the fact that the actual change in diesel fuel prices between 2016 and 2020 was significantly lower than was forecast in 2016.

Table 7-17 Assumed Truck Rates for 2020

Market	Loading Cost (2019 $/ton)	Transport (2019 mills/ton-mile)
All Markets	1.00	100

7.3.4 Barge and Lake Vessel Rates

As with truck rates, barge rates include loading and transport components, and all flows are considered competitive because river access is open to all barge firms. The transportation matrix subdivides barge moves into three categories, which are based on the direction of the movement (upstream vs. downstream) and the size of barges that can be utilized on a given river. As with the other types of transportation rates forecast in this analysis, the barge rate levels shown in Table 7-18 are expected 2020 rate levels, stated in 2019 dollars.

Table 7-18 Assumed Barge Rates for 2020

Type of Barge Movement	Loading Cost (2019 $/ton)	Transport (2019 mills/ton-mile)
Upper Mississippi River, and Downstream on the Ohio River System	3.80	12.2
Upstream on the Ohio River System	3.50	11.8
Lower Mississippi River	2.75	10.3

Notes:

1. The Upper Mississippi River is the portion of the Mississippi River north of St. Louis.
2. The Ohio River System includes the Ohio, Big Sandy, Kanawha, Allegheny, and Monongahela Rivers.
3. The Lower Mississippi River is the portion of the Mississippi River south of St. Louis.

Rates for transportation of coal by lake vessel on the Great Lakes were forecast on a plant-specific basis, considering the lake vessel distances applicable to each movement, the expected backhaul economics applicable to each movement (if any), and the expected changes in labor costs and fuel and steel prices over the long-term.

7.3.5 Transportation Rates for Imported Coal

Transportation rates for imported coal reflect expectations regarding the long-term equilibrium level for ocean vessel rates, considering expected long-run equilibrium levels for labor, fuel, and equipment costs.

In EPA 2023 Reference Case, it is assumed that imported coal is likely to be used only at plants that can receive this coal by direct water delivery (i.e., via ocean vessel or barge delivery to the plant). The assumption is based on an assessment of recent transportation market dynamics, which suggests that railroads are unlikely to quote rail rates that will allow imported coal to be cost-competitive at rail-served plants. Moreover, import rates are higher for the Alabama and Florida plants than for New England plants because many of the Alabama and Florida plants are barge-served (which requires the coal to be transloaded from ocean vessel to barge at an ocean terminal, and then moved by barge to the plant), whereas most of the New England plants can take imported coal directly by vessel. The assumed costs are summarized in Table 7-25.

7.3.6 Other Transportation Costs

In addition to the transportation rates already discussed, the transportation matrix assumes various other rates that are applied on a case-by-case basis, depending on the logistical nature of a move. These charges apply when coal must be moved between different transportation modes (e.g., rail-to-barge or truck-to-barge) – see Table 7-19.

Table 7-19 Assumed Other Transportation Rates for 2020

Type of Transportation	Rate (2019 $/ton)
Rail-to-Barge Transfer	2.00
Rail-to-Vessel Transfer	2.50
Truck-to-Barge Transfer	2.00
Rail Switching Charge for Short line	2.50
Conveyor	1.00

7.3.7 Long-Term Escalation of Transportation Rates

<u>Overview of Market Drivers</u>

According to data published by the Association of American Railroads (AAR), labor costs accounted for about 33% of the rail industry's operating costs in 2018, and fuel accounted for an additional 16%. The remaining 51% of the rail industry's costs relate primarily to locomotive and railcar ownership and maintenance, and track construction and maintenance.

The performance of various cost indices for the railroad industry over the past four years (1Q2016-1Q2020) is summarized in Figure 7-9. Since the lockdowns related to COVID-19 in the U.S. began on March 16, 2020, the historical performance of the rail cost indices was assessed based largely on "pre-COVID" data. This analysis period was selected in order to focus the analysis on the expected longer-term performance of the rail cost indices during the majority of the 2021-2050 forecast period, and avoid excessive bias toward the near-term economic disruptions related to COVID-19.

As shown in Figure 7-9, the RCAF[72] Unadjusted for Productivity (RCAF-U), which tracks operating expenses for the rail industry, increased at an annualized rate of 1.8% per year in nominal terms during 1Q2016-1Q2020. Since overall inflation (as measured by the GDP Chained Price Index increased by an average of 1.9%/year during the same period, the railroad industry's operating costs decreased by an average of 0.1%/year in real terms during 1Q2016-1Q2020.

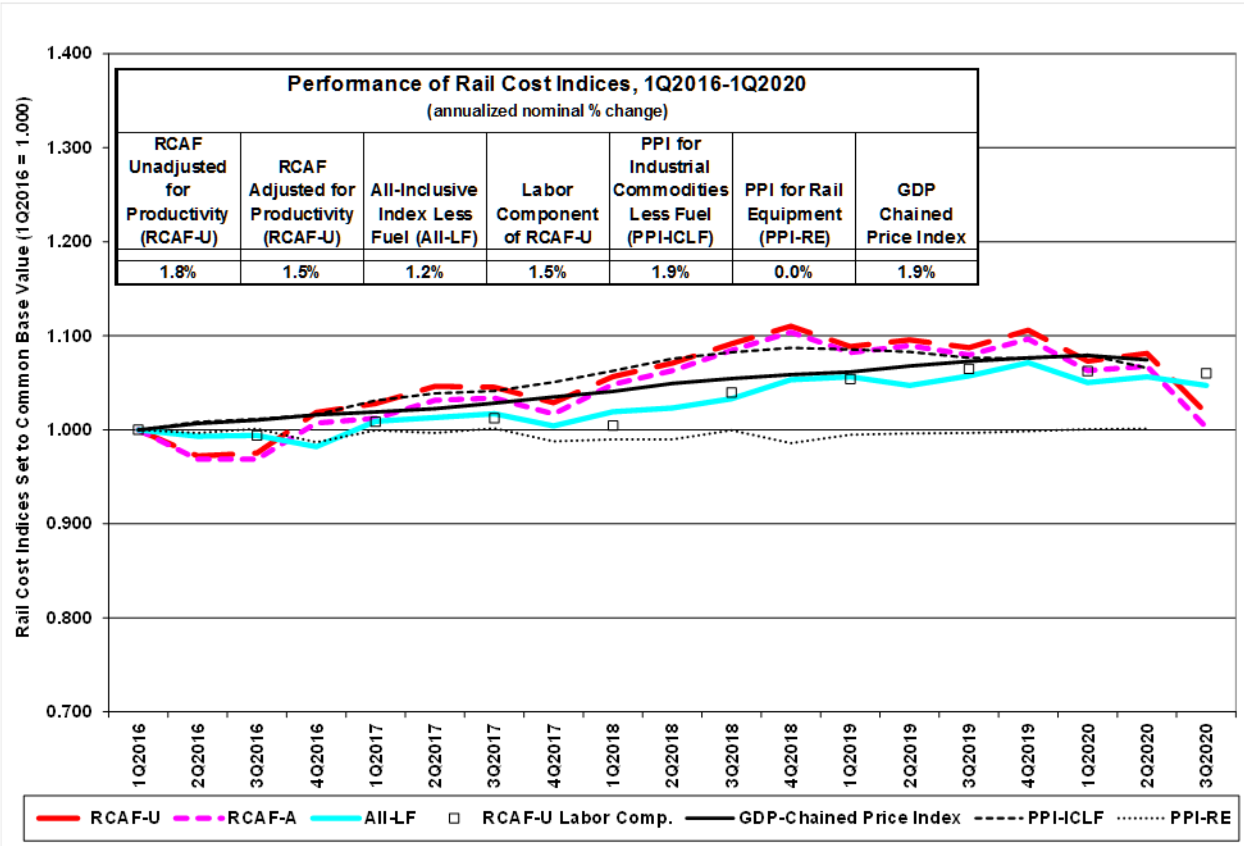
As shown by the All-Inclusive Index Less Fuel (AII-LF), the railroad industry's overall input costs excluding fuel (e.g., labor and equipment costs) decreased by an average of 0.7%/year in real terms during 1Q2016-1Q2020. The railroad industry's labor costs decreased by an average of 0.4%/year in in real terms during the same period.

[72] The Rail Cost Adjustment Factor (RCAF) refers to several indices created for regulatory purposes by the STB, calculated by the AAR, and submitted to the STB for approval. The indices are intended to serve as measures of the rate of inflation in rail inputs. The meaning of various RCAF acronyms that appear in this section can be found in the insert in Figure 7-9.

Since the railroads' labor force is largely unionized, Hellerworx considers the real decline in labor costs during 1Q2016-1Q2020 to be an unusual event, and expects that, on average over the forecast period used in EPA 2023 Reference Case, the rail industry's labor costs are likely to be flat in real terms.

However, since the volume of coal used for electric generation (and thus the volume of coal transported by the rail industry) is expected to continue to decline significantly during the forecast period in most forecast scenarios, there will likely be a long-term surplus of the rail equipment used for coal transportation. Thus, the rail industry's equipment costs are expected to continue to decline in real terms, by an average of 0.5% per year during the forecast period used in EPA 2023 Reference Case.

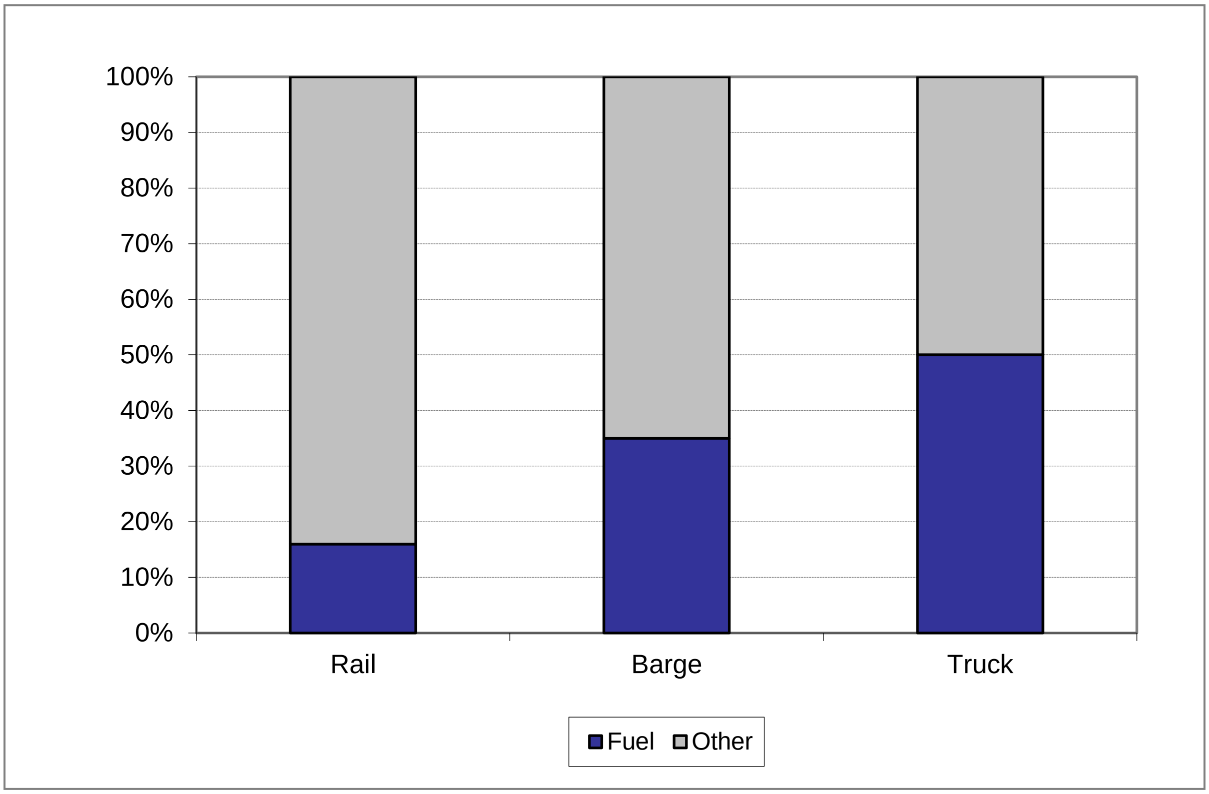
Figure 7-9 Rail Cost Indices Performance (1Q2016-1Q2020)



The other major transportation modes used to ship coal (barge and truck) have cost drivers broadly similar to those for rail transportation (labor costs, fuel costs, and equipment costs). However, a significant difference in cost drivers between the transportation modes relates to the relative weighting of fuel costs for the different transportation modes. Estimates as shown in Figure 7-10 show that, at 2018[73] fuel prices, fuel costs accounted for about 16% of long-run marginal costs for the rail industry, 35% of long-run marginal costs for barges, and 50% of long-run marginal costs for trucks

[73] 2018 was used as the reference point for fuel prices in this analysis because, at the time the coal transportation rate assumptions used in EPA Platform v6 Summer Reference 2021 were finalized in August 2020, the latest analysis of railroad operating expenses available from the AAR contained 2018 data.

Figure 7-10 Long-Run Marginal Cost Breakdown by Transportation Mode



7.3.8 Market Drivers Moving Forward

Diesel Fuel Prices

ICF's forecast of long-term equilibrium prices for diesel fuel used in the transportation sector (see Table 7-20) shows expected prices ranging from about $2.39/gallon in 2020 to about $2.88/gallon in 2050 (2019 real dollars). This represents an average annual real increase in diesel fuel prices of about 0.6%/year during 2020-2050. The coal transportation rate forecast for EPA 2023 Reference Case assumes that this average rate of increase in diesel fuel prices will apply over EPA's entire forecast period.

This is a significantly lower rate of increase in diesel fuel prices than the average real increase of 2.0%/year that was assumed in EPA Platform v6 November 2018 Reference Case, based on the latest forecast that was available from the U.S. Energy Information Administration as of mid-2016 (Annual Energy Outlook 2016, Reference Case forecast for the price of diesel fuel used in the transportation sector.)

Table 7-20 EIA AEO Diesel Fuel Forecast, 2020-2050

Year	Rate (2019 $/gallon)
2020	2.39
2025	2.50
2030	2.79
2035	2.98
2040	2.95
2045	2.94
2050	2.88
Annualized % Change, 2021-2050	0.6%

Source: EIA

Labor Costs

As noted, labor costs for the rail industry are expected to increase at approximately the same rate as overall inflation (flat in real terms), on average, over the forecast period. Labor costs in the barge and truck industries are also expected to increase at approximately the same rate as overall inflation, on average, over the forecast period used in EPA 2023 Reference Case.

Productivity Gains

The most recent data which was available from the AAR at the time the coal transportation rate assumptions used in EPA 2023 Reference Case were finalized in August 2020 (covering 2014-2018), showing that rail industry productivity increased at an annualized rate of approximately 1.0% per year during this period. Since coal-fired generation is expected to continue to face strong competition from natural gas-fired generation and renewables during the forecast period used in EPA 2023 Reference Case (which will significantly limit coal demand), approximately half of the railroad industry's expected productivity gains (0.5% per year) are forecast to be passed through to coal shippers.

The potential for significant productivity gains in the trucking industry is relatively limited since truckload sizes, operating speeds, and truck driver hours are all regulated by law. Although it is possible that increasing the use of electric vehicles may reduce trucking costs to some degree at some point during the forecast period used in EPA 2023 Reference Case, both the timing and the magnitude of this change are very difficult to quantify. Therefore, the potential impact of increasing use of electric vehicles has not been included in the modeling of coal trucking rates for EPA 2023 Reference Case.

Although increased lock outages and the associated congestion on the inland waterway system as the river infrastructure ages may reduce the rate of future productivity gains in the barge industry, limited productivity gains are expected to occur. Since the barge industry is highly competitive, these productivity gains are expected to be largely passed through to shippers.

Long-Term Escalation of Coal Transportation Rates

Based on the foregoing discussion, rail rates are expected to decline at an average rate of 0.7% per year in real terms during the 2021-2050 forecast period used in EPA 2023 Reference Case. Over the same period, barge and lake vessel rates are expected to decrease at an average rate of 0.3% per year, which includes some pass-through of productivity gains in those highly competitive industries. Truck rates are expected to increase at an average rate of 0.3%/year during 2021-2050, largely due to increases in fuel costs. Rates for conveyor transportation and transloading services are expected to be flat in real terms, on average, over the forecast period used in EPA 2023 Reference Case.

The basis for these forecasts is summarized in Table 7-21.

Table 7-21 Summary of Expected Escalation for Coal Transportation Rates, 2020-2050

Mode	Component	Component Weighting	Real Escalation Before Productivity Adjustment (%/year)	Productivity Gains Passed Through to Shippers (%/year)	Real Escalation After Productivity Adjustment (%/year)
Rail	Fuel	16%	0.60%		
	Labor	33%	0.0%		
	Equipment	51%	-0.5%		
	Total	100%	-0.2%	0.5%	-0.7%
Barge & Vessel	Fuel	35%	0.6%		
	Labor & Equip.	65%	0.0%		
	Total	100%	0.2%	0.5%	-0.3%
Truck	Fuel	50%	0.6%		
	Labor & Equip.	50%	0.0%		
	Total	100%	0.3%	0.0%	0.3%
Conveyor	Total		0.0%	0.0%	0.0%
Transloading Terminals	Total		0.0%	0.0%	0.0%

7.3.9 Other Considerations

Estimated Construction Costs for Railcar Unloaders and Rail Spurs at Mine-Mouth Plants

To allow mine-mouth generating plants (i.e., coal-fired generating plants that take all of their current coal supply from a single nearby mine) to access additional types of coal, the costs of constructing facilities that would allow rail delivery of coal were estimated for almost all of the mine-mouth generating plants with total capacity of 200 MW or more.

The facilities needed for rail delivery of coal to generating plants of this relatively large size were assumed to be: a) a rotary dump railcar unloader capable of handling unit train coal shipments, which is estimated to cost about $25 million installed (in 2019$). b) at least three miles of loop track, which would allow for one trainload of coal to be unloaded, and a second trainload of coal to simultaneously be parked on the plant site preparatory to unloading, and c) at least one mile of additional rail spur track to connect the trackage on the plant site with the nearest railroad main line. Since construction costs for rail trackage capable of handling coal trains are estimated at about $3 million per mile (in 2019$), the minimum investment required to construct the facilities needed for rail delivery of coal was estimated at $37 million. In some cases, the length of the rail spur required to reach the nearest main line (which was estimated on a plant-specific basis) is considerably longer than one mile. In cases where a rail spur longer than one mile was required to reach the main line, the cost of the additional trackage was estimated using the same construction cost of $3 million per mile (2019$) referenced earlier.

The total cost of the facilities required for rail delivery of coal was converted to an annualized basis based on the assumption that, for capital recovery estimation purposes, each plant's average coal burn during the forecast period used in EPA 2023 Reference Case should be discounted to 50% of the 2019 historical level[74], and a capital recovery factor of 10.58%.

[74] This is intended to represent aa plausible estimate of the average coal burn that might occur at coal-fired generating plants that remain operational for a significant portion of the 2021-2050 forecast period used in EPA 2023 Reference Case, across a range of different forecasting scenarios.

The cost of transporting additional types of coal to each mine-mouth generating plant was then calculated using the same methodology described earlier in this section and added to the annualized cost for the rail delivery facilities to arrive at an estimated all-in cost for delivering additional types of coal to the mine-mouth plants.

7.4 Coal Exports, Imports, and Non-Electric Sectors Demand

The coal supply curves used in EPA 2023 Reference Case represent the total steam coal supply in the United States. While the U.S. power sector is the largest consumer of thermal coal – roughly 95% of U.S. thermal coal consumption in 2019 was used in electricity generation – non-electricity demand must also be taken into consideration in IPM modeling to determine the market-clearing price.[75] Furthermore, some coal mined within the U.S. is exported out of the domestic market, and some foreign coal is imported for use in electricity generation. These changes in the coal supply must be detailed in the modeling of the coal supply available to coal power plants. The projections for imports, exports, and non-electric sector coal demand are based on EIA's AEO 2023.

In EPA 2023 Reference Case, coal exports and coal-serving residential, commercial, and industrial demand are designed to correspond as closely as possible to the projections in AEO 2023 both in terms of the coal supply regions and coal grades that meet this demand. The projections exclude exports to Canada, as the Canadian market is endogenously modeled within IPM. First, the subset of coal supply regions and coal grades in EPA 2023 Reference Case are identified that are contained in or overlap geographically with those in EIA Coal Market Module (CMM) supply regions and coal grades that are projected as serving exports and non-electric sector demand in AEO 2023. Next, coal for exports and non-electricity demand are constrained by the CMM supply region and coal grade to meet the levels projected in AEO 2023. These levels are shown in Table 7-22, Table 7-23, and Table 7-24.

Table 7-22 Coal Exports in the EPA 2023 Reference Case (Million Short Tons)

Name	2028	2030	2035	2040	2045	2050	2055
East Interior - Bituminous High Sulfur	16.13	12.37	10.04	25.04	26.91	26.36	26.36
East Interior - Bituminous Medium Sulfur	1.15	1.22	1.45	0.00	0.00	0.00	0.00
Northern Appalachia - Bituminous High Sulfur	0.50	0.53	0.59	0.53	0.35	0.22	0.22
Rocky Mountain - Bituminous Low Sulfur	6.64	6.64	6.64	6.64	6.64	5.52	5.52
Western Montana - Bituminous Low Sulfur	0.00	0.00	0.03	7.64	9.76	7.89	7.89
Western Montana - Subbituminous Low Sulfur	23.14	29.82	30.33	0.00	0.00	4.47	4.47
WY Northern PRB - Subbituminous Low Sulfur	10.10	0.00	0.00	17.01	12.30	13.06	13.06

IPM then endogenously determines which IPM coal supply region(s) and coal grade(s) will be selected to meet the required export or non-electric sector coal demand as part of the cost-minimization coal market equilibrium. Since there are more coal supply regions and coal grades in EPA 2023 Reference Case than in AEO 2023, the specific regions and coal grades that serve export and non-electric sector demand are not pre-specified but modeled.

Table 7-23 Residential, Commercial, and Industrial Demand in the EPA 2023 Reference Case (Million Short Tons)

Name	2028	2030	2035	2040	2045	2050	2055
Arizona/New Mexico - Subbituminous Medium Sulfur	0.02	0.02	0.02	0.02	0.02	0.01	0.01
Central Appalachia - Bituminous Low Sulfur	0.88	0.85	0.61	0.54	0.48	0.34	0.34
Central Appalachia - Bituminous Medium Sulfur	3.01	2.87	2.70	2.39	2.18	2.19	2.19
Dakota Lignite - Lignite Medium Sulfur	3.61	3.52	3.27	3.02	2.83	2.84	2.84
East Interior - Bituminous High Sulfur	0.10	0.10	0.11	0.10	0.10	0.10	0.10
East Interior - Bituminous Medium Sulfur	3.54	3.47	3.24	2.97	2.37	2.37	1.80
Northern Appalachia - Bituminous High Sulfur	0.30	0.29	0.27	0.25	0.24	0.25	0.25

[75] https://www.eia.gov/coal/annual/pdf/acr.pdf

Name	2028	2030	2035	2040	2045	2050	2055
Northern Appalachia - Bituminous Medium Sulfur	0.48	0.47	0.42	0.37	0.33	0.32	0.32
Rocky Mountain - Bituminous Low Sulfur	1.96	1.86	1.71	1.51	1.32	1.21	1.21
Southern Appalachia - Bituminous Low Sulfur	0.07	0.07	0.06	0.05	0.05	0.05	0.05
Southern Appalachia - Bituminous Medium Sulfur	0.02	0.03	0.04	0.00	0.00	0.00	0.00
West Interior - Bituminous High Sulfur	0.13	0.13	0.11	0.10	0.09	0.14	0.14
Western Montana - Bituminous Low Sulfur	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Western Montana - Subbituminous Low Sulfur	1.21	1.19	1.11	1.02	0.96	0.97	0.97
WY North/South PRB - Subbituminous Low Sulfur	4.01	3.87	3.48	3.13	2.90	3.04	3.04

Imported coal[76] is only available to 19 coal facilities, which are eligible to receive imported coal. These facilities, which may receive imported coal, along with the cost of transporting this coal to the demand regions, are in Table 7-25. The total U.S. imports of steam coal are limited to AEO 2023 projections as shown in Table 7-24.

Table 7-24 Coal Import Limits in the EPA 2023 Reference Case (Million Short Tons)

	2028	2030	2035	2040	2045	2050	2055
Annual Coal Imports Cap	0.74	0.70	0.52	0.49	0.50	0.69	0.69

[76] Imported coal is assumed to have a SO_2 emission factor of 1.1 lbs/MMBtu, a mercury emission factor of 7.74 lbs/TBtu, and a HCl emission factor of 0.018 lbs/MMBtu.

Attachment 7-1 Mining Cost Estimation Methodology and Assumptions

Labor Costs

Productivity and labor cost rates are utilized to estimate the total labor cost associated with the mining operation. The estimate excludes labor involved in any coal processing/preparation plant.

Labor productivity is used to calculate mine labor and salaries by applying an average cost per employee hour to the labor productivity figure reported by MSHA or estimated based on comparable mines.

Labor cost rates are estimated based on employment data reported to MSHA. MSHA data provides employment numbers, employee hours worked, and tons of coal produced. These data are combined with labor rate estimates from various sources such as union contracts, census data and other sources such as state employment websites to determine a cost per ton for mine labor. Hourly labor costs vary between United Mine Workers of America (UMWA) and non-union mines, including benefits and payroll taxes. Employees assigned to preparation plants, surface activities, and offices are excluded from this category and are accounted for under coal washing costs and mine overhead.

Surface Mining

The prime (raw coal) strip ratio and overburden volume are estimated on a year-by-year basis. Estimates are entered of the amount of overburden [77] moved each year, split by method to allow for different unit mining costs. The unit rate cost for each method excludes any drill and blast costs, and labor costs, as these are accounted for separately. Drill and blast costs are estimated as an average cost per volume of prime overburden. If applicable, dragline re-handle is estimated separately, and a summation gives the total overburden moved.

- The different overburden removal methods are:
- Dragline - the estimated volume of prime overburden moved
- Dragline re-handle - the estimated volume of any re-handled overburden
- Truck and shovel - including excavators.
- Other - examples would be dozer push, front-end loader, or cast blasting. If overburden is moved by cast blasting, the unit rate is taken to be zero as the cost is already included in the drill and blast estimate.
- Surface mining costs also include the cost of coal mining estimated on a raw-ton basis.

Underground Mining

Raw coal production is split by type into either continuous miner or longwall. Cost estimates can be input either on a unit rate or a fixed dollar amount, as the cost structure of underground mining generally has a large, fixed component from year to year. Costs are divided into:

- Longwall
- Continuous miner
- Underground services

Underground services costs cover categories such as ventilation, conveyor transport, gas drainage, and secondary roof support etc.

[77] Overburden refers to the surface soil and rock that must be removed to uncover the coal.

Mine Site Other

This covers any mine site costs that are outside the direct production process. Examples are ongoing rehabilitation/reclamation, security, and community development costs.

Raw Haul

Costs for transporting raw coal from the mining location to the raw coal stockpile at the coal preparation plant or rail load out. A distance and a unit rate allow for an increasing cost over time if required.

List of tables that are uploaded directly to the web:

Table 7-25 Coal Transportation Matrix in EPA 2023 Reference Case

Table 7-26 Coal Supply Curves in EPA 2023 Reference Case