SCHOOL OF BUSINESS, ECONOMICS AND TECHNOLOGY

KING INSTITUTE FOR REGIONAL ECONOMIC STUDIES (KIRES)

KIRES Report No. 20, February 2019

The Shift From Coal To Natural Gas In The U.S. Electric Power Sector: Impact On Global Greenhouse Gas Emissions And The Southwest Virginia Coalfield Economy.

Introduction

According to the U.S. Energy Information Administration (EIA), coal consumption in the United States in 2018 is expected to be the lowest in 39 years. The decline in coal consumption has been led by a precipitous slide in coal used for electricity generation, which normally accounts for more than 90 percent of the domestic consumption of coal. In this paper, we analyze the economic and government policy factors underlying coal's decline, the impact on the Southwest Virginia economy, and the extent to which the substitution of natural gas for coal in the U.S. electric power sector has lowered carbon dioxide emissions. Carbon dioxide is the most abundant greenhouse gas (GHG), accounting for around 80 percent of U.S. GHG emissions and more than 70 percent of global GHG emissions.

Background

The economic health of the U.S. coal industry is overwhelmingly linked to the demand for coal for electricity generation. The high-water mark for coal-fired electricity generation was in 2007 and 2008 when more than 1,040 million short tons of coal annually were consumed in the electric power sector and coal accounted for nearly 50 percent of U.S. electricity generation. In 2007 and 2008, and in prior years, coal was significantly less expensive than natural gas. This all changed beginning in 2009 when large amounts of natural gas produced from shale formations entered the market. The annual average cost of coal relative to natural gas (hereinafter, the cost ratio) more than doubled between 2008 to 2009, from 0.0.23 to 0.47. The cost ratio has remained well above 2008 and earlier levels, ranging from annual averages of 0.45 to 0.73 during the 2010 to 2017 time period. Consequently, consumption of coal in the electric power sector fell to 665 million tons in 2017 (Table 1) and coal's share of fuels used for electric power was around 30 percent.

Coal consumption in the electric power sector in 2018 may be down about 5 percent from 2017, based on data for the first 10 months of 2018. This decline is fully explained by the 5-percent decline in generation capacity from November 2017 to November 2018. The U.S. Energy Information Administration (EIA) expects additional year-to-year reductions in coal use in the electric power sector of 7.5 - 8 percent in 2019 and 2020. If these forecasts materialize, 545 million short tons of coal would be consumed for electric power in 2020, 48 percent below our base year (2008) total.

Environmental regulations have played a role in coal's decade-long decline. The Mercury and Air Toxics Standards (MATS) rule was finalized by the Environmental Protection Agency (EPA) in 2012 with an April 2015 initial compliance date. According to EIA, the MATS rule required all coal- and oil-fired generators that sell power and have a capacity greater than 25 megawatts to comply with emissions limits for toxic air pollutants associated with fuel combustion such as mercury, arsenic, and heavy metals. EIA reports that, at the time, the MATS rule applied to 76 percent of all operating coal units, which represented 99 percent of generation capacity. Faced with the decision to invest in expensive emission control technology or shutting down, many coal-fired power plants were retired with the largest declines in generation capacity occurring in 2015 and 2016. The initial retirements were mostly the older, smaller and less efficient units, already struggling to compete with natural gas. The bottom line is that coal-fired generation capacity in the United States totaled 313 gigawatts (GW; one billion watts) in 2008, the base year for our analysis. By the end of 2017, coal-fired generation capacity was 256 GW, an 18 percent decline (Table 5).

However, the wave of retirements continues and EIA expects the amount of coal-fired generation capacity retired in 2018 to rival that of 2016. Latest available data show that capacity was around 245 GW in November 2018. More retirements are looming in the near future as the economic environment for electricity generation is expected to favor natural gas and renewables, wind and solar. EIA expects another 9.3 GW of coal-fired generation capacity to be retired in 2019-20 combined.

In addition to the expanding market share for natural gas-fired generation over the past decade, coal's generation share has been reduced, to a lesser extent, by the growing generation share of renewables, especially wind and solar. Whereas the growth of natural gas-fired generation has been driven by a persistently higher cost ratio (coal /natural gas) and EPA regulations affecting coal, increased use of wind and solar has been encouraged by a combination of state and federal policies/subsidies.

The Background section draws heavily from two of EIA's *Today in Energy* articles: "U.S. coal consumption in 2018 expected to be the lowest in 39 years," December 28, 2018 and "Coal plants installed mercury controls to meet compliance deadlines," September 18, 2017. *Today in Energy* archives may be accessed at https://www.eia.gov/todayinenergy/. The forecasts for 2019 and 2020 are from EIA's *Short-Term Energy Outlook: Coal*, January 15, 2019, accessed at https://www.eia.gov/outlooks/steo/report/coal.php. Capacity data may be found in EIA's *Electric Power Monthly*, January 2019, http://www.eia.gov/electricity/monthly/current_month/epm.pdf.

Research Results and Conclusions

Effect on Global Greenhouse Gas Emissions

Summary: Because coal is more carbon intensive than natural gas, CO2 emissions will decline as coal is replaced by natural gas in the electricity generation fuel mix. Coal-fired generation emits 2.32 times as much CO2 as natural gas to produce an equivalent amount of electricity. This calculation is based on the cumulative 2009-17 values for electricity generation and CO2 emissions presented in the "Sum 2009-17" row in Table 2. The ratio = (13,740/4,142) x (9,577,388/13,692,299) = 2.32.

We estimate that the shift from coal to natural gas in the U.S. electric power sector reduced cumulative U.S. carbon dioxide emissions by 1.685 billion metric tons (bmt) during the 2009 – 2017 period. Global cumulative GHG emissions over the same time period were reported at 437 bmt, CO2 equivalents (Table 3). Therefore, cumulative global GHG emissions during 2009 – 2017 were lower by 0.39 percent as a result of the shift from coal to natural gas in the U.S. electric power sector. The methodology for our study is presented below.

While the shift from coal to natural gas has had a small effect on global GHG emissions, it has helped the U.S. be a world leader in reducing emissions over the past decade. The U. S. share of global GHG emissions fell from 16 percent in 2007 to 13 percent in 2017 (Table 3). Moreover, while U.S. total GHG emissions declined from 7.2 to 6.6 bmt from 2007 to 2017, emissions in the rest of the world increased from 37.2 to 44.3 bmt. China and India accounted for most of the increase; China's share of global GHG emissions was nearly 27 percent in 2017.

Methodology: The relationship between CO2 emissions and electricity generation is pictured in Figure 1 for coal and Figure 2 for natural gas. The simple regression equations for the relationships are shown on the graphs, where emissions are in million metric tons and generation is in million kilowatt hours. The data for estimating the equations are presented in Table 2. The R^2 values indicate that the year-to-year changes in CO2 emissions are fully explained by year-to-year changes in generation. The estimated regression equations shown in Figures 1 and 2 are based on annual data. The equations can be modified to predict cumulative totals for the nine-year (inclusive) 2009-2017 period by multiplying the intercept values by 9. The resulting equations are:

Coal CO2 = (9 x 37.99) +0.0009782(Kwh) = 341.91 + 0.0009782(Kwh).

Natural gas CO2 = (9 x 51.29) + 0.0003846(Kwh) = 461.61 + 0.0003846(Kwh).

We test the estimated equations by comparing actual cumulative values for CO2 against those predicted by the equations. The equations performed flawlessly as evidenced below (cumulative generation and emission values are in Table 2, "Sum 2009 – 17" row.):

Predicted coal CO2 = 341.91 + (0.0009782 x 13,692,299) = 13,736 mmt; actual value is 13,740.

Predicted natural gas CO2 = 461.61 + (0.0003846 x 9,577,388) = 4,145 mmt; actual value is 4,142.

Sum = 17,882 mmt; actual value is 17,883.

To estimate the reduction in CO2 emissions arising from the substitution of natural gas for coal in the U.S. electric power sector, we freeze the generation shares for coal and natural gas at their base year (2008) levels, approximately 0.71 for coal and 0.29 for natural gas. These shares are calculated from the generation data presented in the "2008 Base" row of Table 2. Cumulative generation values for coal and

natural gas based on their 2008 shares are presented in the "Sum 2009-17, 2008 shares" row in Table 2. Based on 2008 shares, estimated cumulative CO2 emissions are:

Coal CO2 = 314.91 + (0.0009782 x 16,532,218) = 16,514 mmt.

Natural gas CO2 = 461.61 + (0.0003846 x 6,737,469) = 3,053 mmt.

Sum = 19,567 mmt.

The shift from coal to natural gas in the U.S. electric power sector resulted in a reduction in cumulative global CO2 emissions of 1,685 million metric tons (19,567 less 17,882) during 2009-17,a reduction of 0.39 percent. Cumulative global GHG emissions during 2009 – 2017 were 437 billion metric tons, or 437,000 mmt (Table 3).

The primary greenhouse gases are carbon dioxide, methane, nitrous oxide and the F-gases (fluorinated gases). Scientists convert the gases to carbon dioxide equivalents to calculate total GHG emissions. In 2017, carbon dioxide accounted for 73 percent of global GHG emissions. Methane was a distant second at 18 percent. Carbon dioxide accounted for 78 percent of U.S. GHG emissions and methane 10 percent. These percentages were calculated from emissions data reported in the Netherlands study referenced in Table 3.

Impact on the SW Virginia Economy

Summary: The downward trend in coal production has had a significant impact on the Southwest Virginia economy. There was a slight uptick in coal production and employment in 2017 owing to greater U. S. exports of both metallurgical and thermal coal. Even so, coal mining employment at 2,660 was little more than one-half the recent high of 5,261 achieved in 2011. Moreover, adjusted for inflation, earnings from coal mining employment fell nearly 60 percent over the same time period (Table 4).

Earnings from coal mining have a significant spillover or "multiplier" effect on other sectors of the Southwest Virginia economy. For this study we examined the impact on Buchanan, Dickenson and Wise (includes Norton city) counties, the areas most affected by coal's downturn. For the three-county region, we estimate an earnings multiplier of 1.90, meaning that for every one-dollar decrease in earnings from coal mining, an additional 90 cents in earnings are lost by households employed in all other sectors of the region's economy.

Inflation-adjusted earnings from coal mining fell by $281 million (2017 dollars) from 2011 to 2017, a 59 percent decrease. Over the same time period, total private nonfarm (PNF) earnings declined by $589 million (2017 dollars), a 36 percent decrease. The region has become more dependent on government transfer payments as lost earnings from coal mining have not been replaced by earnings in other areas of the private sector. In 2011 transfer payments were 35 percent of total personal income in the three - county region; in 2017, they were 41 percent of total personal income.

Methodology: The dependence of total private nonfarm earnings on earnings from coal mining is shown in Figure 3. The slope (1.90) of the estimated regression equation is the multiplier described above. The R^2 value indicates that nearly 95 percent of the year-to-year changes in PNF earnings are explained by annual changes in earnings from coal mining.

Behind Coal's Decline – Market Forces and Government Policies

The two primary factors behind the decade-long downturn in coal's share of electric power generation are lower natural gas prices and EPA regulations that have made coal-fired generation costlier. By definition, coal-fired electricity generation is the product of the capacity utilization rate and capacity. From 2008 to 2017, the utilization rate for coal-fired power plants fell from 0.734 to 0.537, a decrease of 27 percent; capacity declined 18 percent, from 313,322 to 256,547 megawatts (Table 5).

Our analysis indicates that for the 2008-17 period annual changes in the coal-to- natural gas cost ratio explain 89 percent (R^2) of annual changes in the average capacity utilization rate for coal-fired power plants (Figure 4). The 2017 utilization rate, identified in Figure 4, was affected by a drop in the overall demand for electricity. This reduced the explanatory power of the estimated regression equation; for 2008 – 2016 data, the R^2 value is 93 percent. At any rate, there is solid evidence that changes in the capacity utilization rate are closely related to changes in the cost ratio.

Analysis of the reduction in coal-fired generation capacity is more complex. It is tempting to say that coal plant retirements primarily are due to EPA regulations as the initial wave of retirements coincided with the implementation of the MATS rule described above. And, there was no reduction in coal-fired generation capacity during 2009 – 2011 as coal plant operators reacted to the unfavorable cost ratio for coal by lowering the utilization rate (Table 5). No doubt, lower natural gas prices and the expectation that lower prices would prevail into the foreseeable future have played a role in coal plant retirements as well, especially the more recent retirements.

Another factor that likely affects coal plant retirement decisions is the "threat" of new regulations being implemented to curb carbon emissions. An example is the Clean Power Plan (CPP) which was scheduled to take effect in 2022, pending judicial review. The CPP would place a cap on carbon emissions from power plants and, if implemented, would likely hasten the pace of coal-fired power plant retirements. The Trump administration has renounced the CPP, but there is a chance it could be resurrected by a future administration. In addition, there is public discussion of other proposals to limit emissions, such as a carbon tax.

Tables and Charts

Table 1.	Consumption of Coal in the Electric Power Sector and Fuel Costs.			
	Mil. Short Tons	$/Mil. BTU	$/Mil. BTU	Cost Ratio
Year	Coal Quantity	Coal Cost	Natural Gas Cost	Coal/Natural Gas
2007	1,045.1	1.77	7.11	0.249
2008	1,040.6	2.07	9.01	0.230
2009	933.6	2.21	4.74	0.467
2010	975.1	2.27	5.09	0.446
2011	932.5	2.39	4.72	0.506
2012	823.6	2.38	3.42	0.696
2013	858	2.34	4.33	0.540
2014	851.6	2.37	5.00	0.474
2015	738.4	2.22	3.23	0.687
2016	678.6	2.11	2.87	0.733
2017	665.0	2.06	3.37	0.611
Source for coal quantity and fuel cost data: Table 6.2 and Table 9.9, *Monthly Energy Review*, U.S. Energy Information Administration (EIA), December 21, 2018.				

Table 2. Electricity Generation and Carbon Dioxide Emissions, Electric Power Sector.						
	Electricity Generation, Million KWH			CO_2 Emissions, Million Metric Tons		
Year	Coal	Natural Gas	Sum	Coal	Natural Gas	Sum
2008 Base	1,968,838	802,372	2,771,209	1,959	362	2,322
2009	1,741,123	841,006	2,582,129	1,741	373	2,114
2010	1,827,738	901,389	2,729,127	1,828	399	2,227
2011	1,717,891	926,290	2,644,181	1,723	409	2,132
2012	1,500,557	1,132,791	2,633,348	1,511	493	2,004
2013	1,567,722	1,028,949	2,596,671	1,571	444	2,016
2014	1,568,774	1,033,172	2,601,947	1,569	444	2,013
2015	1,340,993	1,237,656	2,578,650	1,350	527	1,877
2016	1,229,663	1,279,380	2,509,043	1,241	547	1,788
2017	1,197,838	1,196,754	2,394,592	1,206	507	1,713
Sum 2009 – 17	13,692,299	9,577,388	23,269,687	13,740	4,142	17,883
Sum 2009-17, 2008 shares	16,532,218	6,737,469	23,269,687			
Source for annual generation and emissions data: Table 7.2b and Table 12.6, *Monthly Energy Review*, U.S. Energy Information Administration (EIA), December 21, 2018. Sums may not add due to rounding.						

Table 3. Trends in Total Greenhouse Gas Emissions			
	Total GHG Emissions, CO2 Equivalents, Billion Metric Tons		
Year	United States	Global	U.S. Share
2007	7.2	44.4	0.162
2008	7.0	44.7	0.157
2009	6.6	44.3	0.149
2010	6.9	46.4	0.148
2011	6.8	47.8	0.143
2012	6.7	48.5	0.137
2013	6.8	49.2	0.137
2014	6.9	49.8	0.138
2015	6.7	49.9	0.135
2016	6.6	50.2	0.132
2017	6.6	50.9	0.131
Sum 2009-17	60.6	437.0	

Source for GHG emissions*: Trends in global CO2 and total greenhouse gas emissions: 2018 report*, PBL Netherlands Assessment Agency, May 12, 2018. The values for the U.S. are slightly different than those reported by the U.S. Environmental Protection Agency (EPA) in *Inventory of U.S. Greenhouse Emissions and Sinks: 1990 – 2016*. The EPA has not reported U.S. total GHG emissions for 2017. Totals may not add due to rounding.

Table 4. Worker Compensation and Coal Mining Employment 2009 – 2017.			
		Compensation, Million 2017 $'s	
Year	Employment	Mining[1]	Total Private Nonfarm
2009	4,646	403	1,487
2010	4,957	462	1,647
2011	5,261	480	1,640
2012	4,998	434	1,474
2013	4,521	369	1,305
2014	3,627	345	1,230
2015	2,993	263	1,175
2016	2,417	183	1,024
2017	2,660	199	1,051

Data source: The inflation-adjusted compensation values are based on current dollar values found in *Local Area Personal Income and Employment*, Bureau of Economic Analysis (BEA), U.S. Department of Commerce, November 2017. The Consumer Price Index (CPI) was utilized to calculate the inflation-adjusted values.

[1] Values for Buchanan County are for the NAICS category "Mining, Except Oil and Gas." Because of disclosure issues, values for Dickenson and Wise counties (plus Norton) are for the broad category, "Mining, Quarrying and Oil and Gas Extraction." We believe the year-to-year changes are mostly, if not entirely, due to changes in coal miner compensation.

Employment numbers are from the *Annual Coal Report*, U.S. Energy Information Administration (EIA), various issues. Although the numbers are for Virginia, they are without doubt highly correlated with the year-to-year changes in coal mining employment in the three-county region, the center of Virginia's coal production.

Table 5. Coal-Fired Power Plants: Capacity, Capacity Factor and Coal-to-Natural Gas Cost Ratio			
Year	Net Summer Capacity, Megawatts[1]	Capacity Factor[2]	Cost Ratio
2008	313,322	0.734	0.229
2009	314,294	0.651	0.467
2010	316,800	0.679	0.446
2011	317,640	0.637	0.505
2012	309,680	0.567	0.696
2013	303,306	0.598	0.540
2014	299,094	0.611	0.474
2015	279,720	0.547	0.690
2016	266,620	0.533	0.735
2017	256,547	0.537	0.611
Source for capacity and capacity factors*:* Table 4.2.A and Table 4.8.A, *Electric Power Annual 2017*, U.S. Energy Information Administration (EIA), October 2018. Cost ratios are from Table 1 above. [1]A megawatt is one million watts of electricity. [2] EIA uses the term "capacity factor;" we use the terms capacity factor and utilization rate interchangeably.			

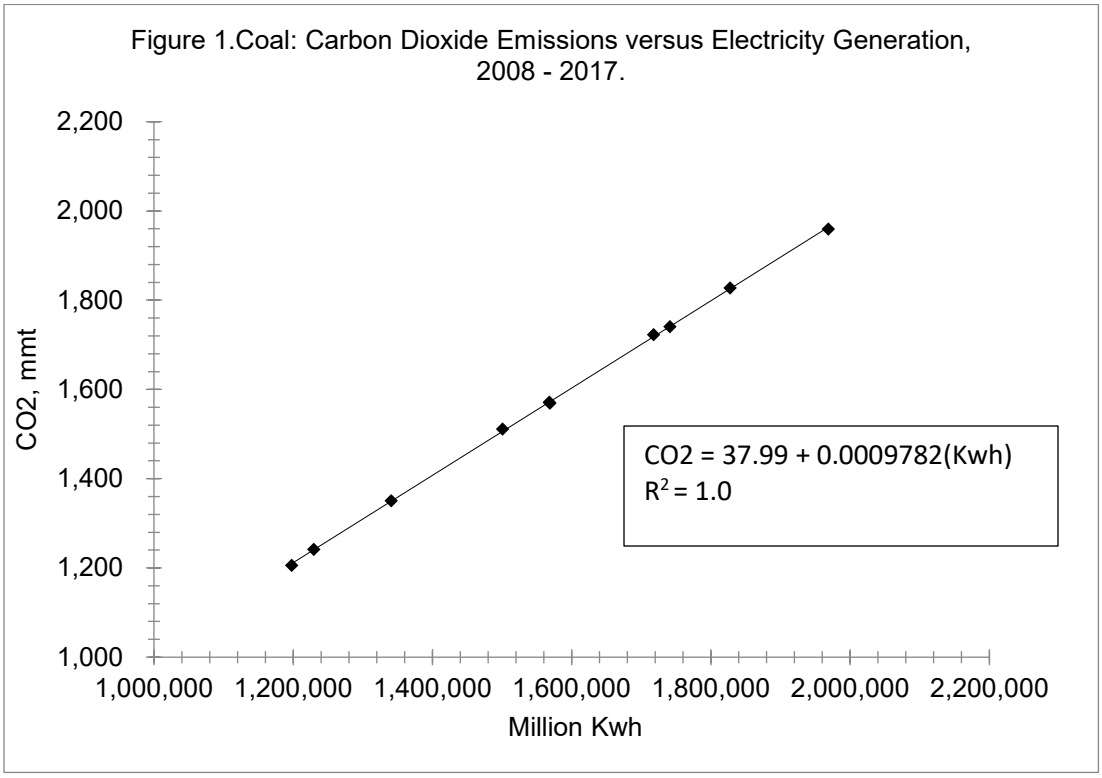


Figure 2. Natural Gas: Carbon Dioxide Emissions versus Electricity Generation, 2008 - 2017

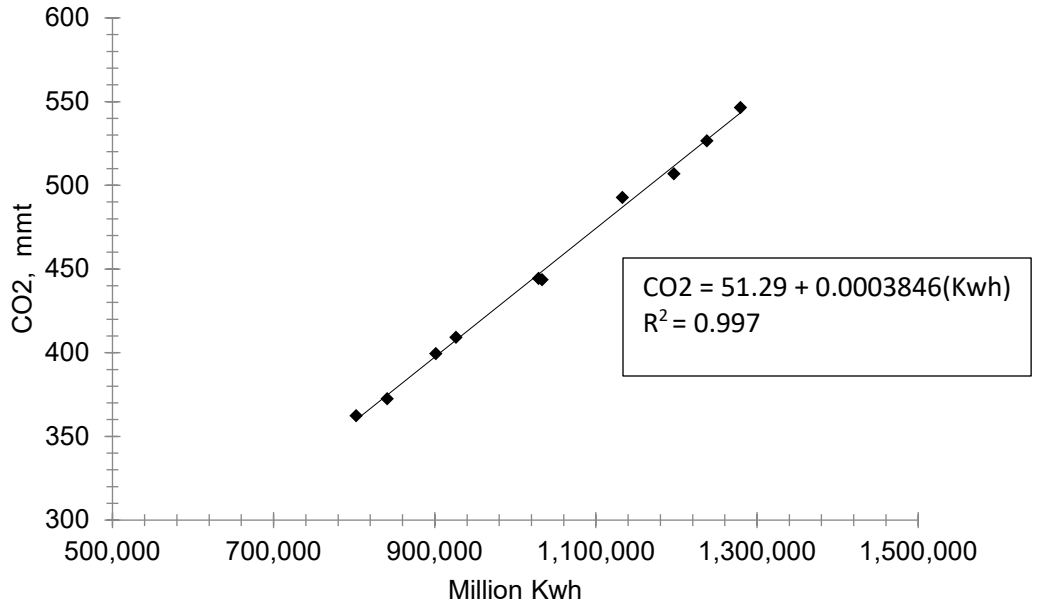
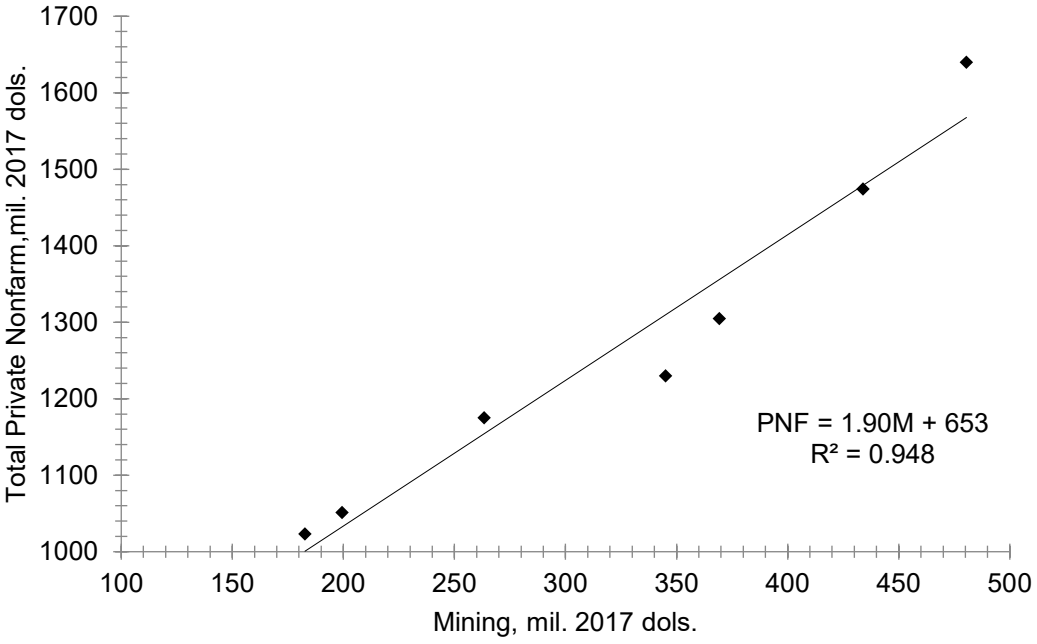
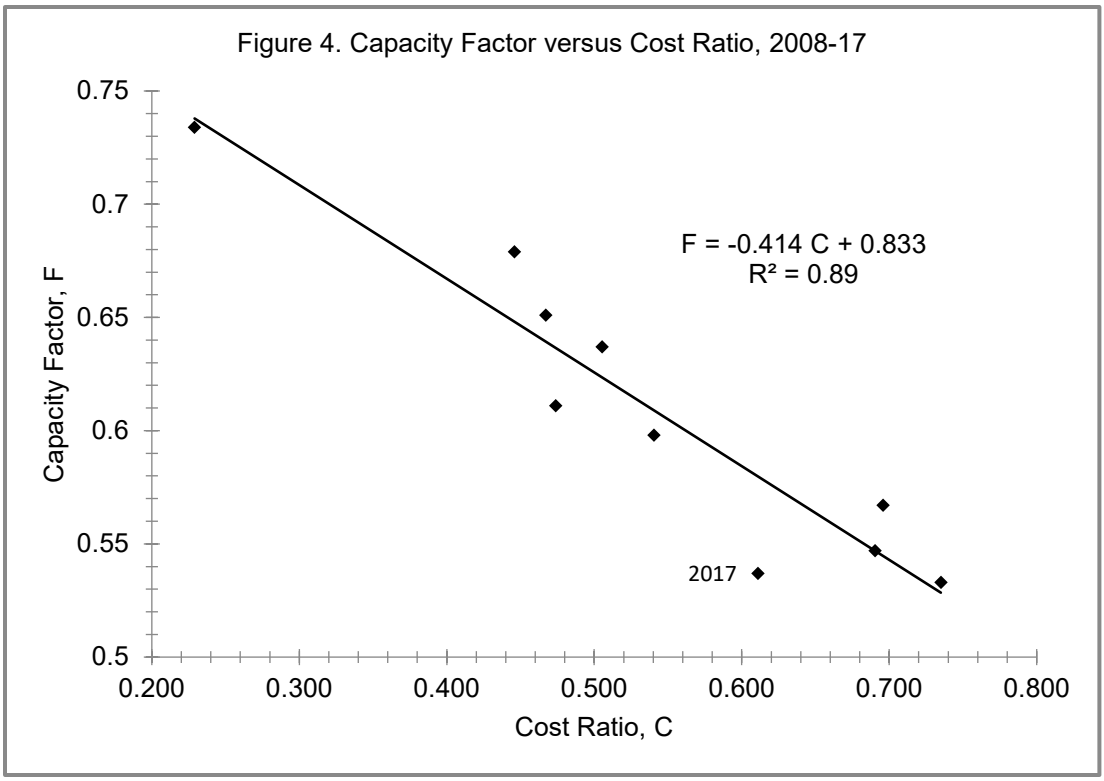


Figure 3. Worker compensation: Total Private Nonfarm (PNF) vs. Mining (M), 2011 - 2017





KIRES Report No. 20 was prepared by Dr. Sam Evans, Associate Professor of Economics and Co-director of KIRES, with contributions from King University business majors Kelsey March, Robert Wilkinson and Joey Mammolenti.