U.S. Energy Information Administration

Electricity Monthly Update

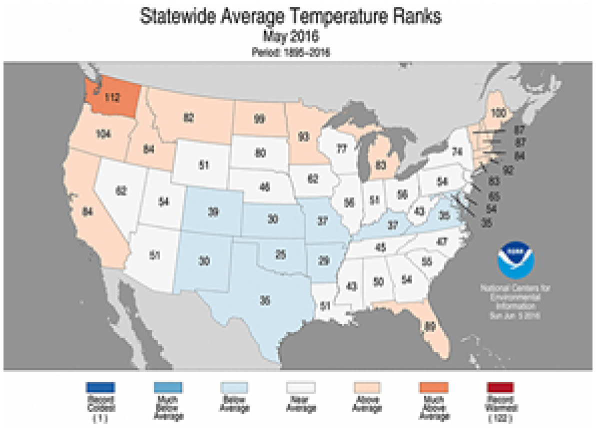
With Data for May 2016 | **Release Date:** July 26, 2016 | **Next Release Date:** August 24, 2016

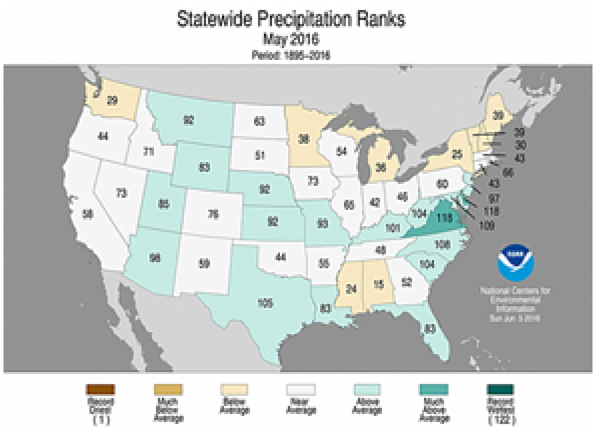
Highlights: May 2016

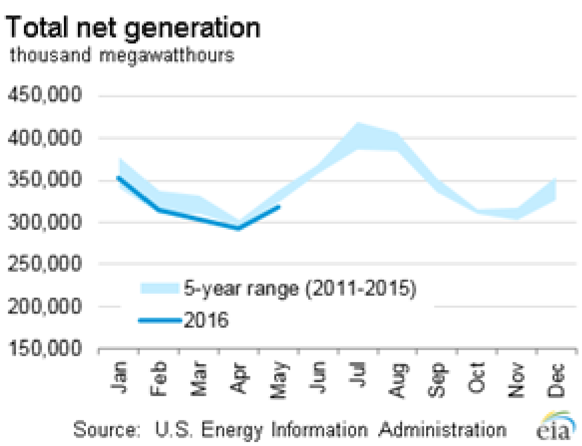
- U.S. coal stockpiles are still at relatively high levels and only decreased 0.3% to 195 million tons from the previous month.
- Low natural gas prices helped keep wholesale electricity prices towards the bottom of the 12-month range in spite of some higher peak demand levels that occurred towards the end of the month.
- For the seventeenth consecutive month, the price of natural gas at Henry Hub was below the price of Central Appalachian coal on a $/MWh basis.

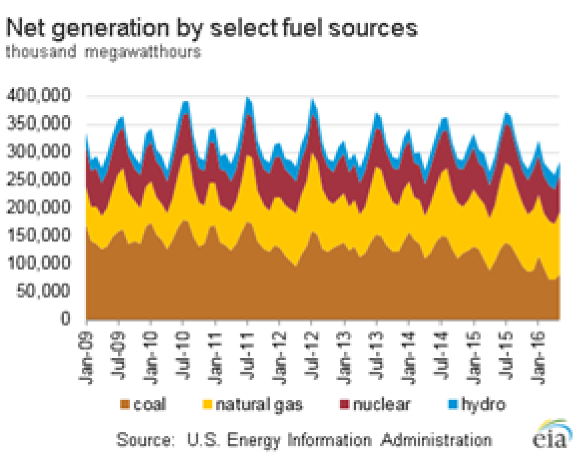
Key Indicators

	May 2016	% Change from May 2015
Total Net Generation (Thousand MWh)	317,739	-1.6%
Residential Retail Price (cents/kWh)	12.80	-1.2%
Retail Sales (Thousand MWh)	280,649	-1.6%
Cooling Degree-Days	106	-15.9%
Natural Gas Price, Henry Hub ($/MMBtu)	1.97	-32.2%
Natural Gas Consumption (Mcf)	839,403	9.2%
Coal Consumption (Thousand Tons)	45,165	-21.1%
Coal Stocks (Thousand Tons)	195,601	12.8%
Nuclear Generation (Thousand MWh)	66,563	1.1%

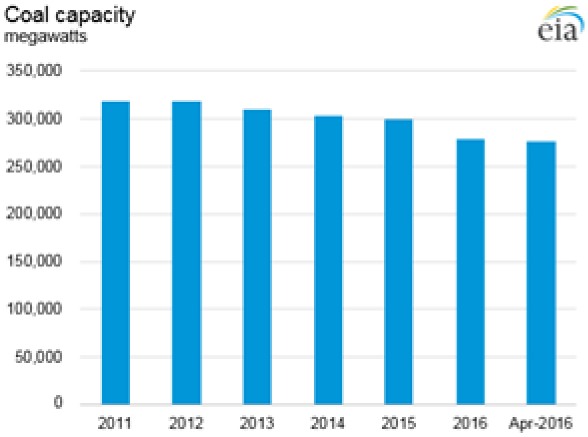








Operating coal-fired generating capacity has declined 15% since 2011 in response to low natural gas prices and environmental regulatory compliance



Source: U.S. Energy Information Administration, Form EIA-860 Annual Electric Generator Report

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EIA recently released preliminary data from its annual survey of electric generators (EIA-860), which provides the electric generating capacity of all units with a capacity of 1 megawatt (MW) or greater. The most important trends over the past few years have been large increases in natural gas, solar and wind generating capacities along with a significant decline in coal generating capacity.

Coal-fired generating capacity in the United States has fallen 15% over the past six years, dropping from 317 gigawatts (GW) at the end of 2010 to 276 GW in April 2016. This decrease is primarily attributable to the competitive pressure from low natural gas prices, which lowers the marginal cost of natural gas-fired generation, and the costs and technical challenges of environmental compliance measures.

Because the EIA-860 data also provide information on pollution control equipment at electric power plants, investments in these technologies can be assessed. For example, a significant amount of pollution control equipment was recently installed in response to the U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS). MATS establishes emissions limits for toxic air pollutants associated with coal combustion such as mercury, arsenic, and heavy metals. Between January 2015 and April 2016, about 87 GW of coal-fired power plants installed pollution control equipment, nearly 20 GW of coal capacity retired, and about 5.6 GW of coal capacity switched to natural gas as the main fuel source.

Of the 87 GW of coal capacity that installed pollution control equipment to comply with MATS, activated carbon injection (ACI) was the dominant compliance strategy. More than 73 GW of coal-fired capacity installed ACI systems in 2015 and 2016, effectively doubling the amount of coal capacity with ACI. According to EIA data, the average capital cost of an ACI system was $5.8 million over 2015 and 2016

Other compliance strategies reported on the 2015 EIA-860 include the modification of existing emissions control equipment, the addition of new equipment or capabilities, or some combination of operational changes and new investments to improve mercury capture or to achieve other environmental control objectives, such as reducing emissions of particulate matter or nitrogen oxide. Overall, the preliminary EIA-860 data indicate that operators of coal-fired power plants invested at least $6.1 billion between 2015 and April 2016 to comply with MATS or other environmental regulations.

Preliminary 2015 EIA-860 data can be useful in assessing changes to electric generating capacity such as growth in renewable and natural gas capacity along with decreases in coal capacity. These data can also indicate how power plants responded to market and regulatory pressures, which can be useful when looking at the causes behind the capacity changes.

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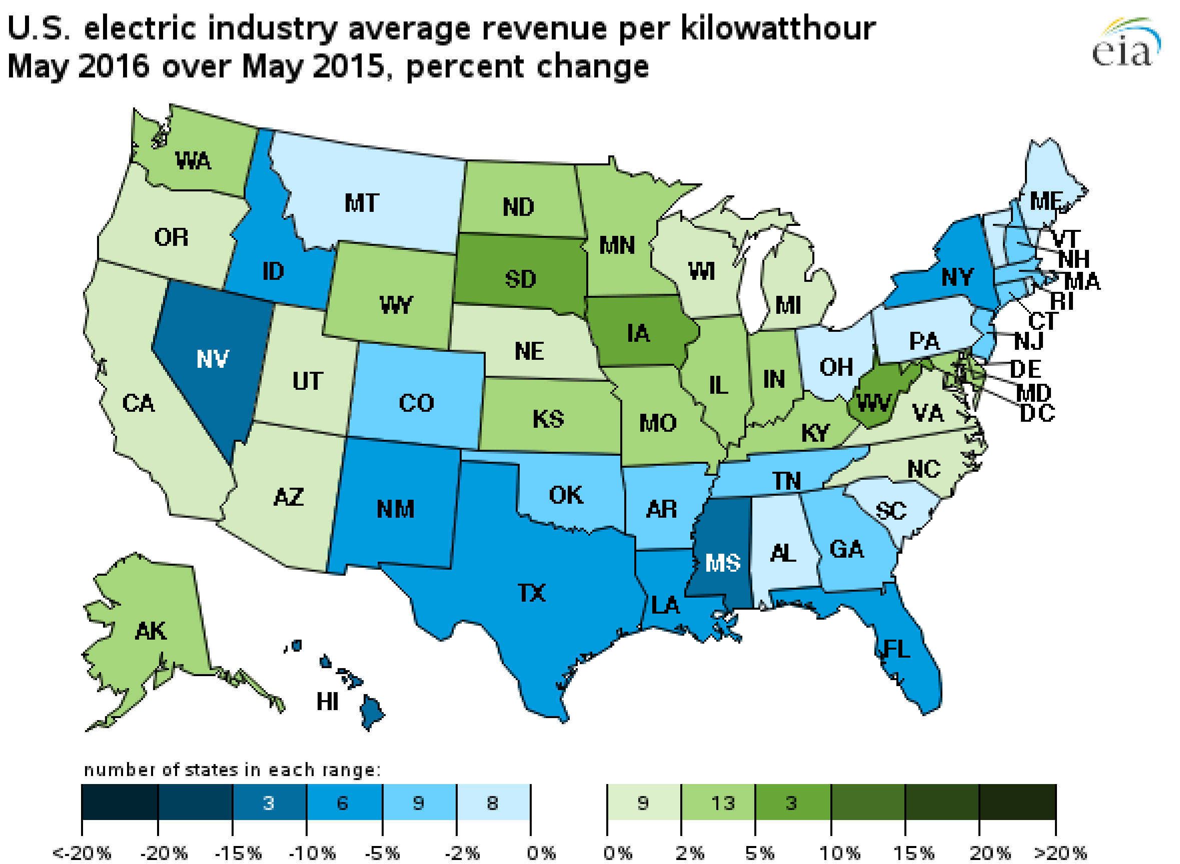
End Use: May 2016

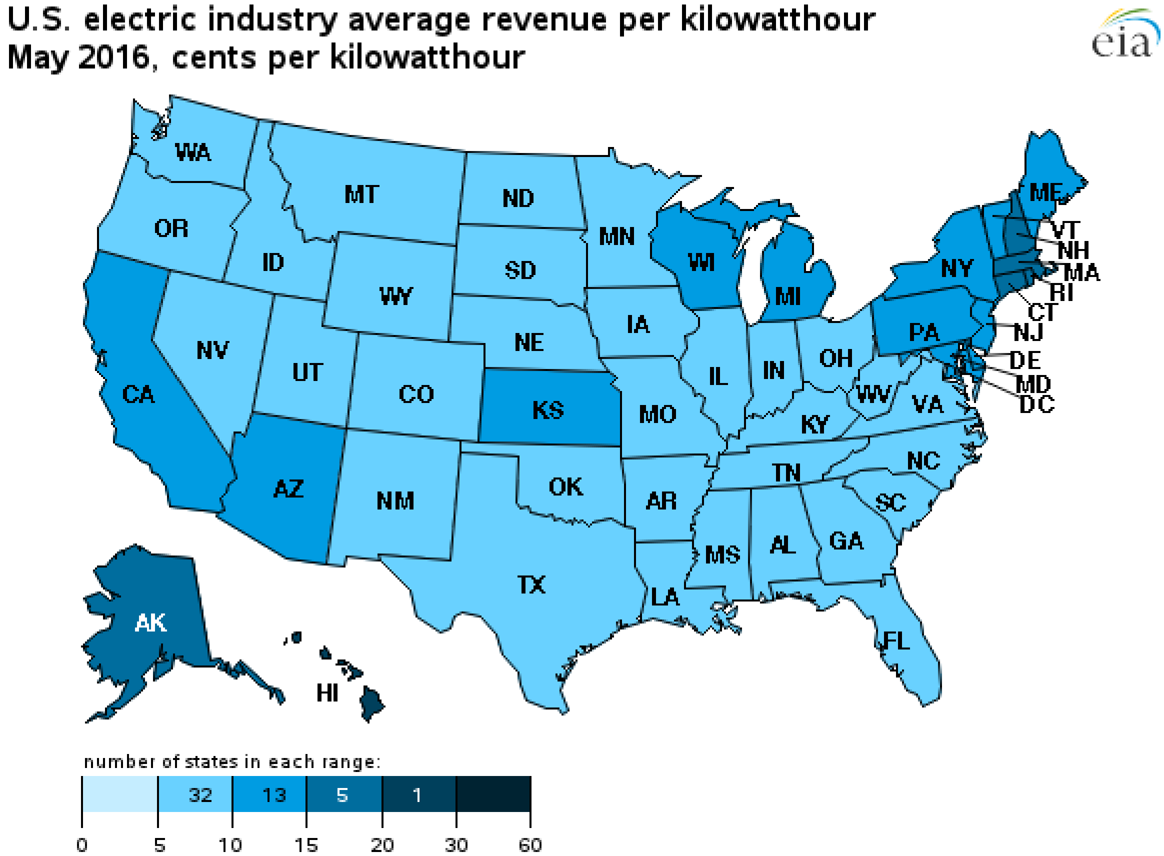
Retail rates/prices and consumption

In this section, we look at what electricity costs and how much is purchased. Charges for retail electric service are based primarily on rates approved by state regulators. However, a number of states have allowed retail marketers to compete to serve customers and these competitive retail suppliers offer electricity at a market-based price.

EIA does not directly collect retail electricity rates or prices. However, using data collected on retail sales revenues and volumes, we calculate average retail revenues per kWh as a proxy for retail rates and prices. Retail sales volumes are presented as a proxy for end-use electricity consumption.

Average revenue per kWh by state





Average revenue per kilowatthour figures decreased in 26 states in May compared to last year. The largest declines were found in Nevada (down nearly 13.4%), Mississippi (down 13%), and Hawaii (down 11.4%). Twenty-four states and the District of Columbia increased compared to last year, led by West Virginia (up 9.75%), South Dakota (up 8.64%), Iowa (up 5.5%), and Washington (up 4.3%).

Retail Service by Customer Sector

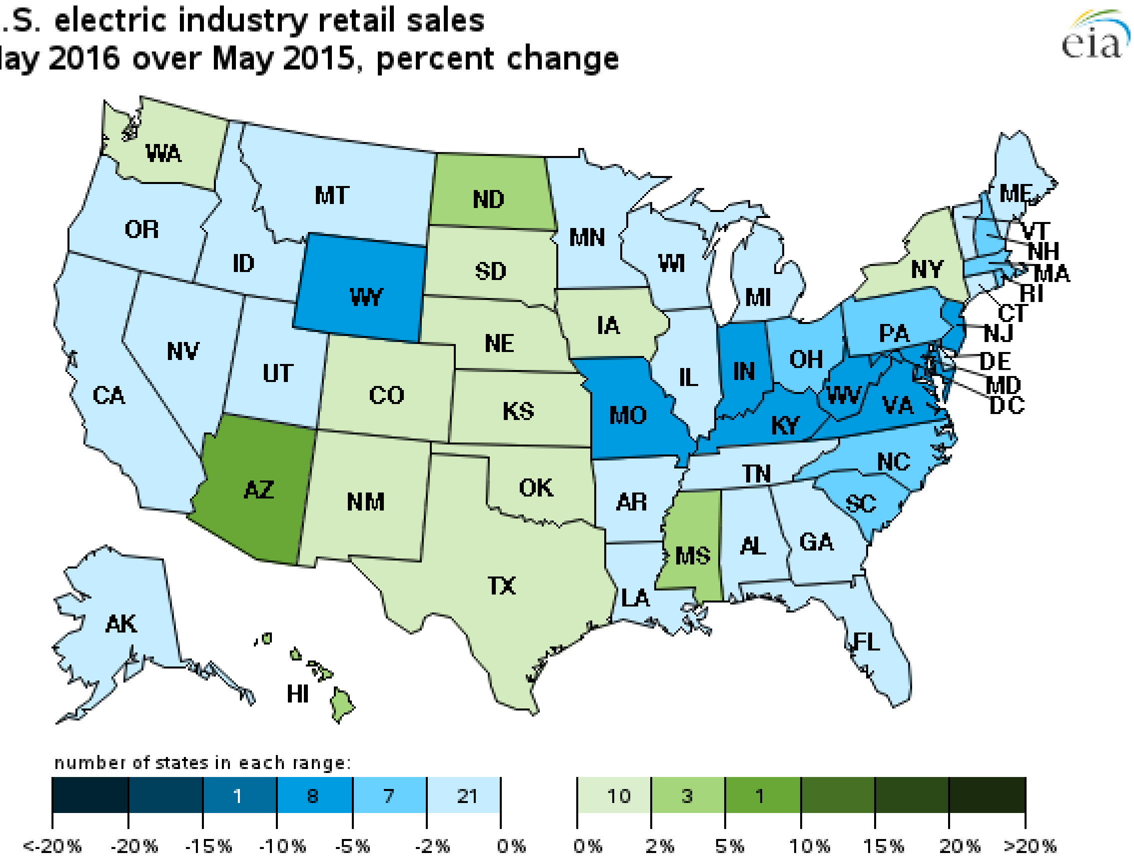
	Average Revenues/Sales (¢/kWh)		Retail Sales (1000s MWh)		
End-use sector	**May 2016**	**Change from May 2015**	**May 2016**	**Change from May 2015**	**Year to Date**
Residential	12.80	-1.2%	93,867	-1.1%	528,662
Commercial	10.25	-1.8%	107,939	-1.1%	528,851
Industrial	6.54	-2.5%	78,258	-3.1%	380,823
Transportation	9.13	-7.7%	585	-4.2%	3,104
Total	**10.06**	**-1.6%**	**280,649**	**-1.6%**	**1,441,440**

Source: U.S. Energy Information Administration

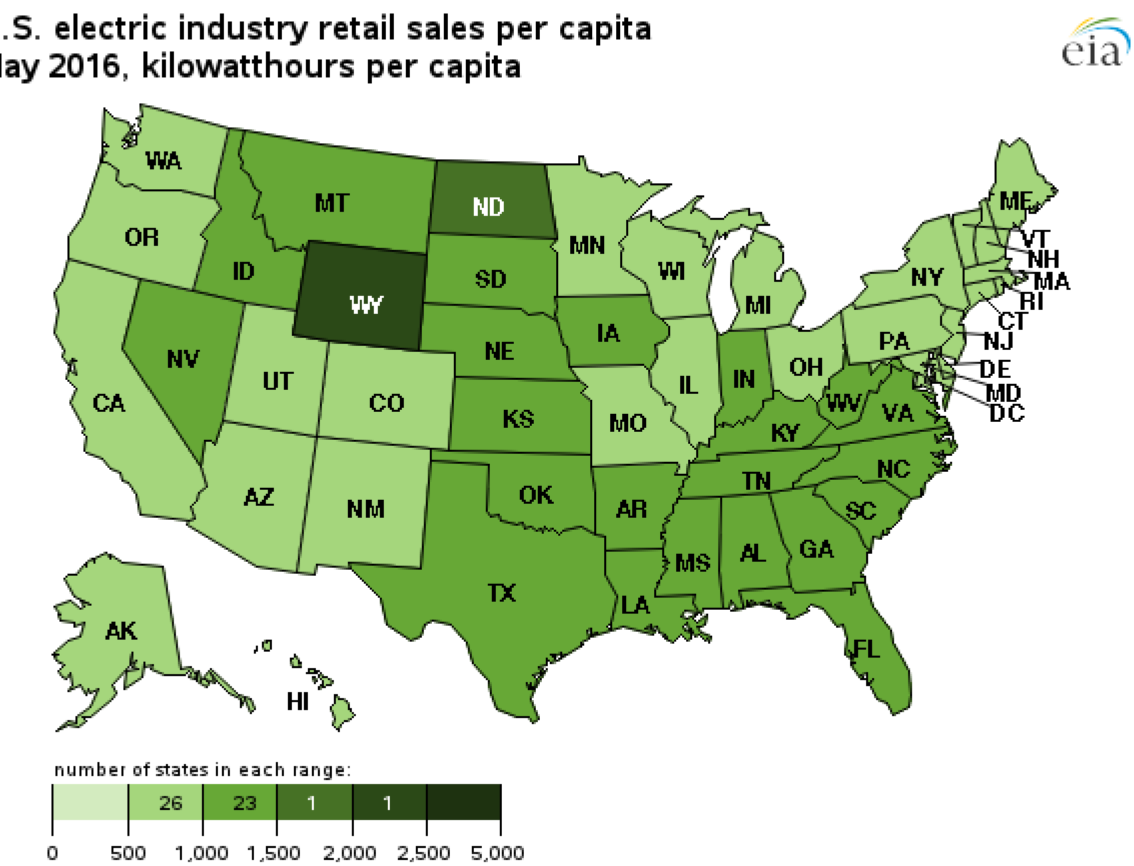
Total average revenues per kilowatthour were down 1.6% to 10.06 cents in May compared to last year. All sectors were down on the month, from a 7.7% drop in the Transportation sector to a 1.2% drop in the Residential sector. Retail sales were down 1.6% to 280,649 gigawatthours (GWh), with declines also across all sectors.

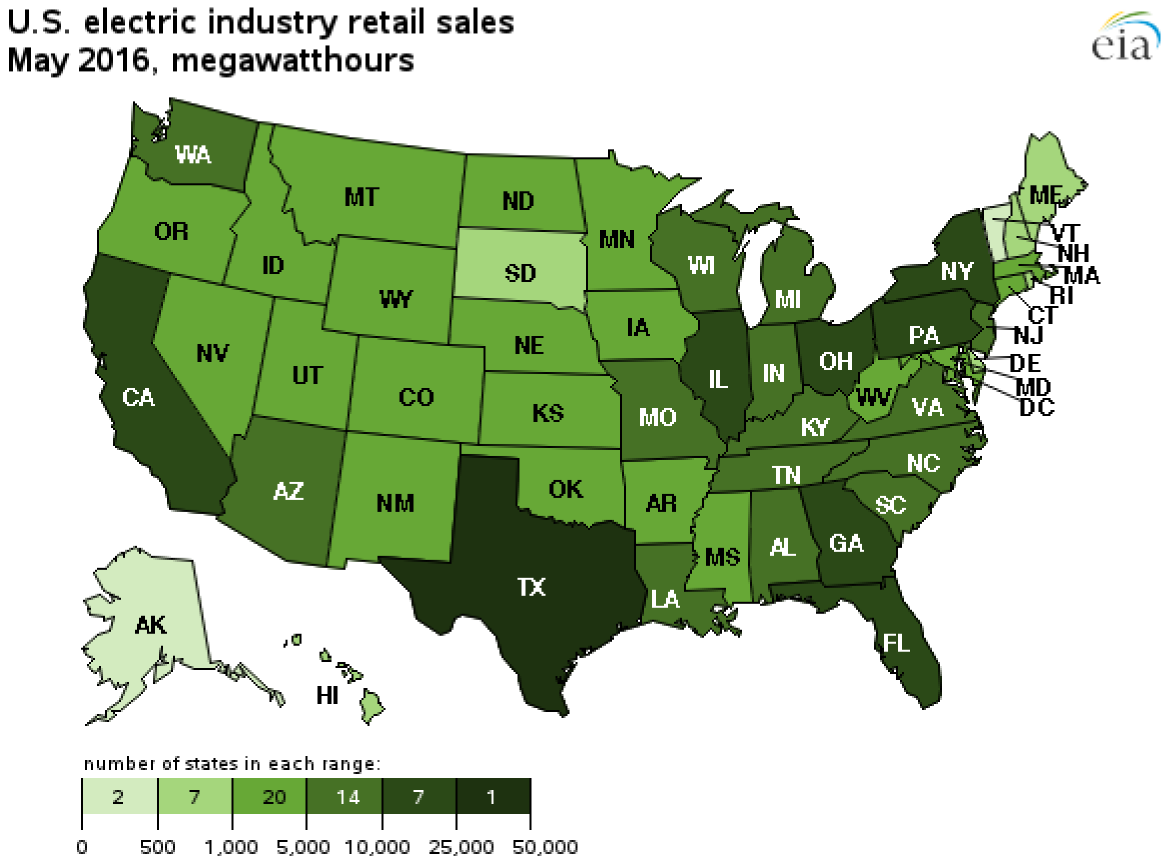
Retail sales

U.S. electric industry retail sales
May 2016 over May 2015, percent change



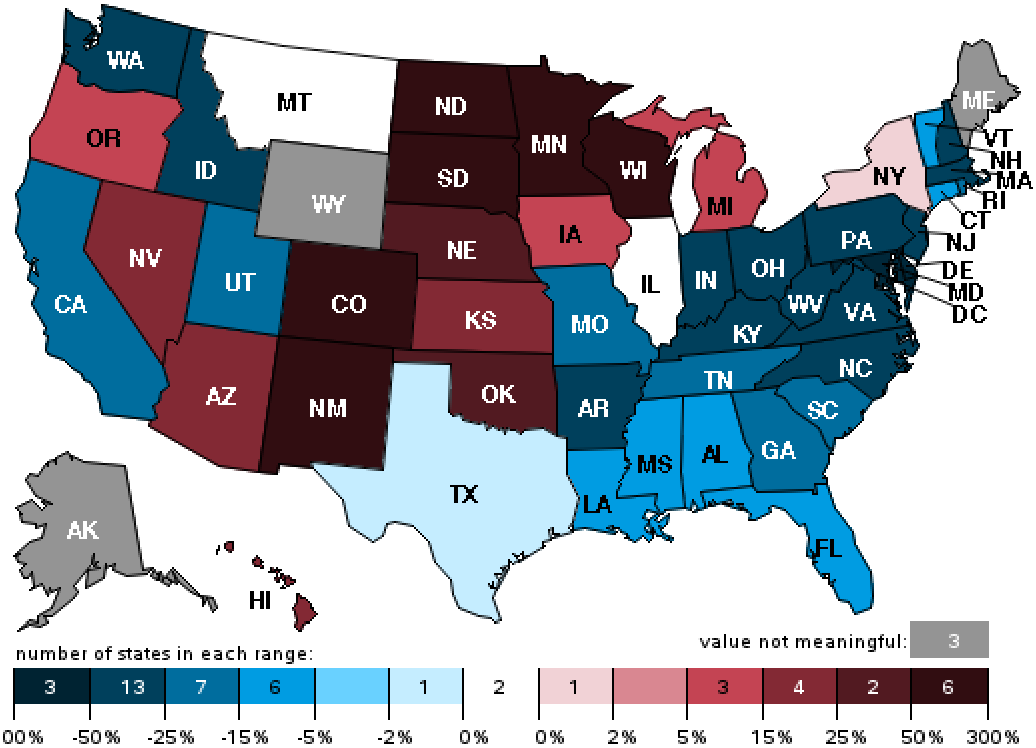
U.S. electric industry retail sales per capita
May 2016, kilowatthours per capita





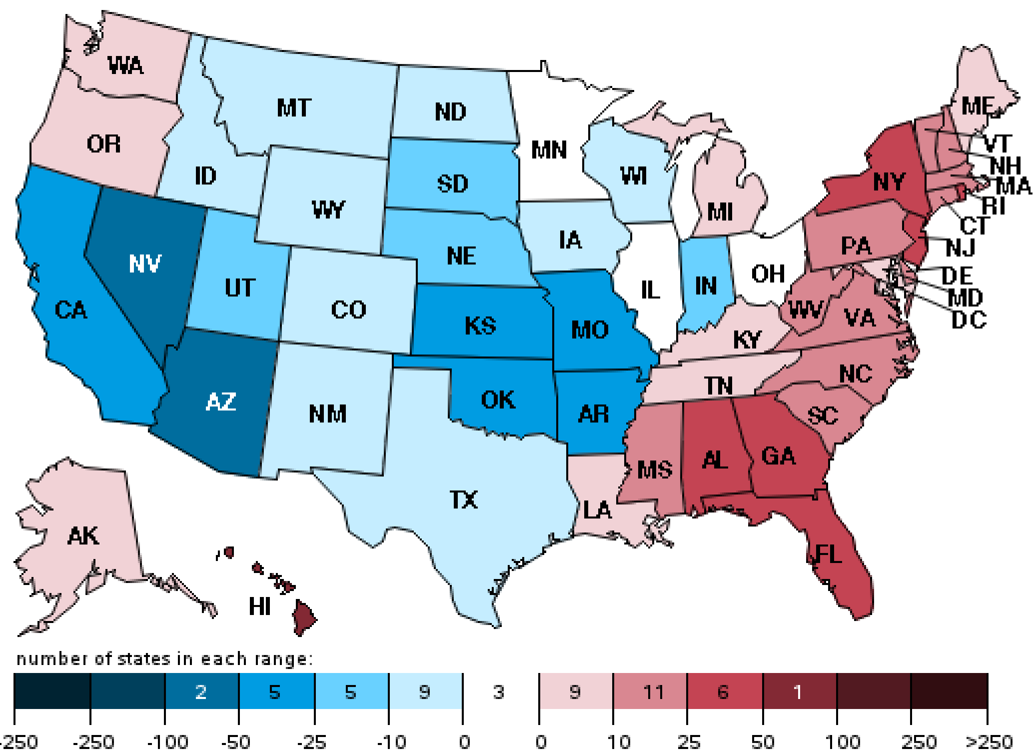
State retail sales volumes were down in 37 states and the District of Columbia in May compared to last year. The District of Columbia recorded the largest year-over-year decline, down just over 11%. Maryland, Kentucky and Virginia had the next largest declines, all down 8-9%. Fourteen states had retail sales volume increases in May, led by Arizona (up over 5%), Hawaii (up over 3%), and North Dakota (up nearly 3%).

U.S. cooling degree days
May 2016 over May 2015, percent change



Source: U.S. Energy Information Administration, based on National Oceanic and Atmospheric Administration data

U.S. cooling degree days deviation from normal,
May 2016



Source: U.S. Energy Information Administration, based on National Oceanic and Atmospheric Administration data

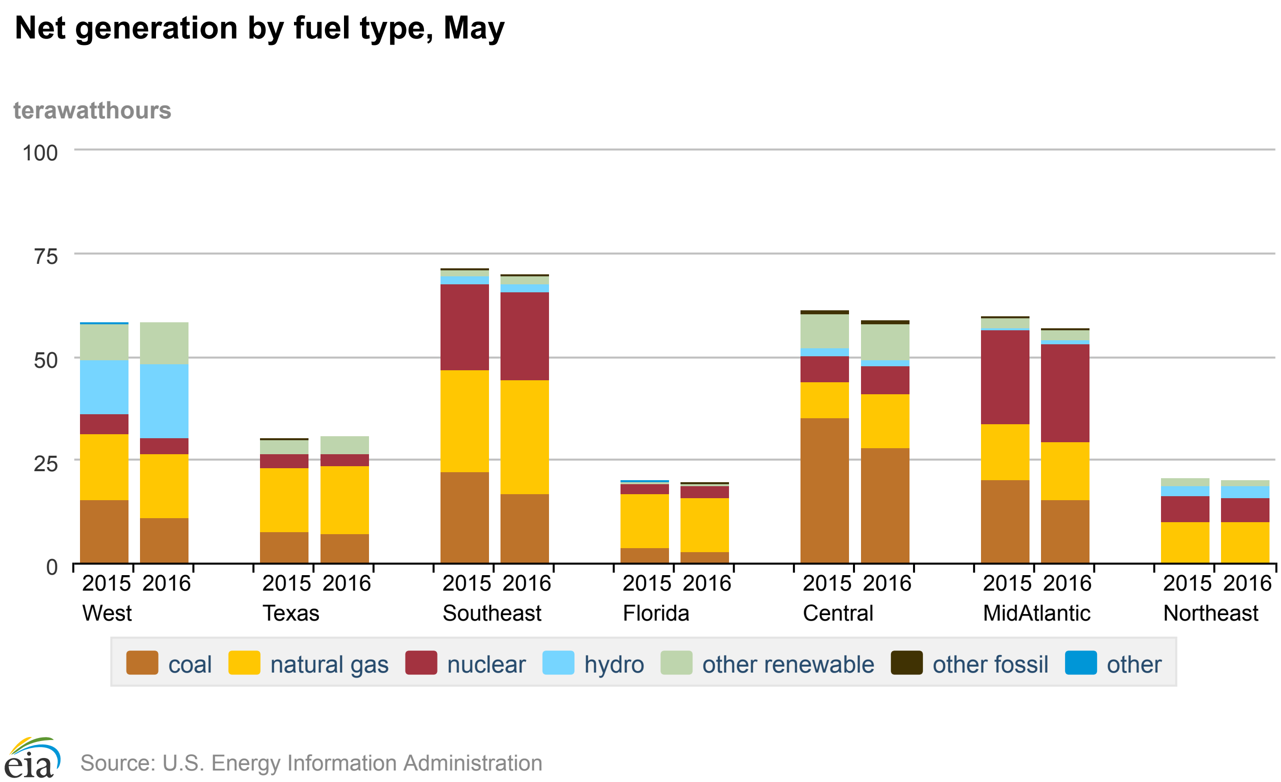
Cooling Degree Days (CDD) measure the daily variation in average temperature above a 65 degree Fahrenheit baseline, chosen as a proxy for minimum heating or cooling energy demand. CDDs were lower in 29 states and the District of Columbia in May, indicating cooler weather, with these states largely in the eastern US. Those with the largest year-over-year declines were the District of Columbia, Maryland, Delaware and Virginia. Sixteen states had higher levels of CDDs compared to last May, indicating warmer weather, with most of these states in the Midwest and West. The states with the largest year-over-year increases were Colorado, Wisconsin, North Dakota and Minnesota.

Resource Use: May 2016

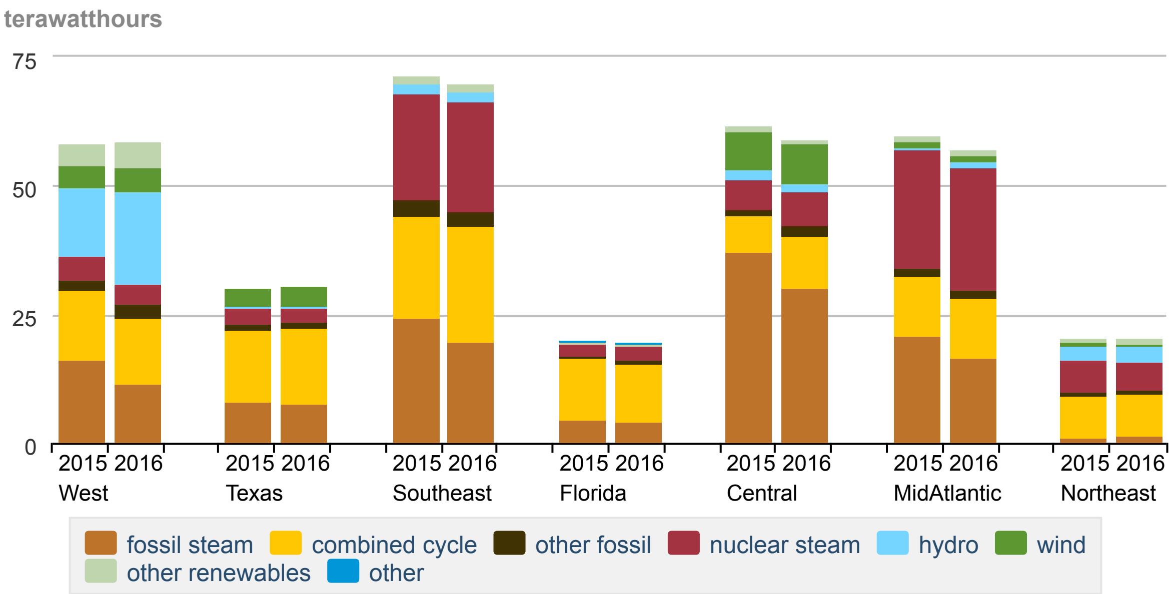
Supply and fuel consumption

In this section, we look at the resources used to produce electricity. Generating units are chosen to run primarily on their operating costs, of which fuel costs account for the lion's share. Therefore, we present below, electricity generation output by fuel type and generator type. Since the generator/fuel mix of utilities varies significantly by region, we also present generation output by region.

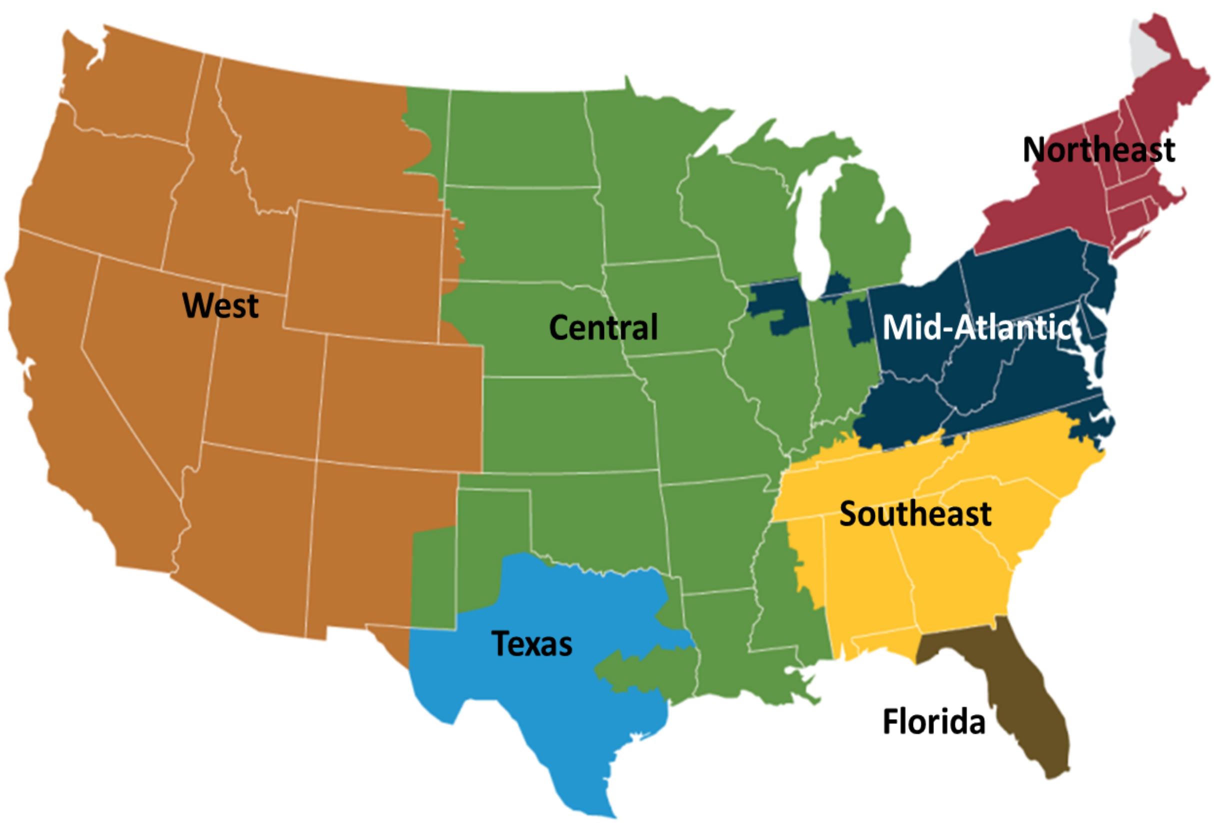
Generation output by region



Net generation by generator type, May



Source: U.S. Energy Information Administration

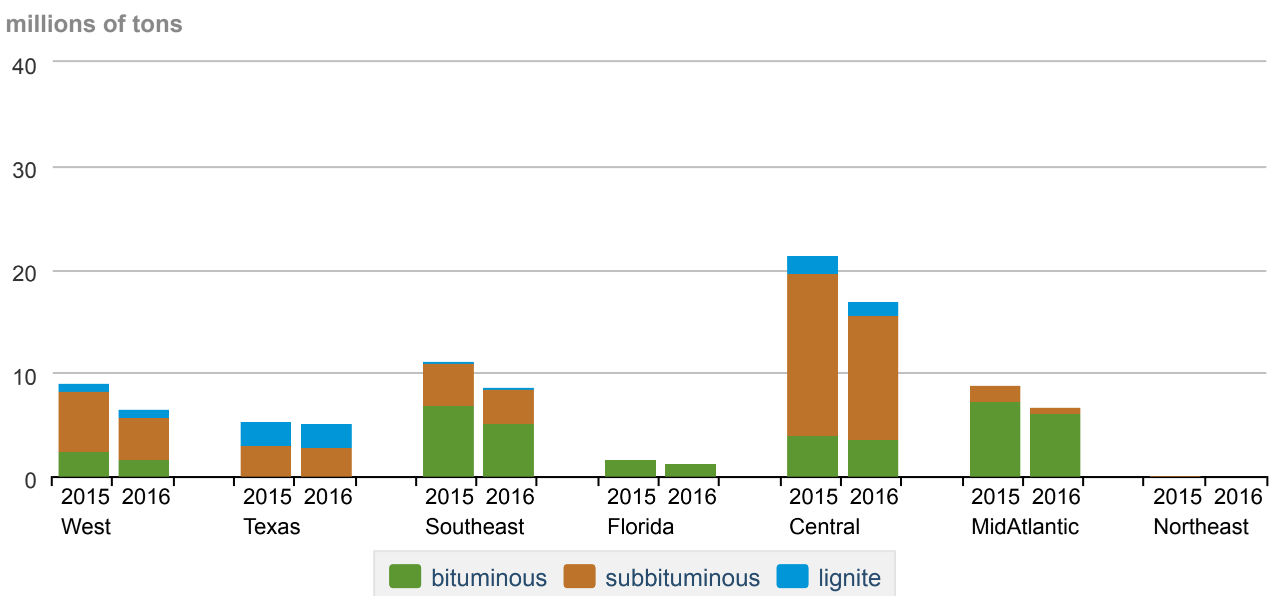


Net generation in the United States decreased 1.6% from the previous May. This occurred, in part, because the country, as a whole, experienced slightly higher temperatures last May than in May 2016, which led to a decreased need for residential cooling this year and thus, a decrease in electricity generation. At the regional-level, the only part of the country that saw a sizeable year-over-year increase in electricity generation was Texas, which saw total electricity generation increase 1.8% due to above average temperatures experienced this May in Texas compared to the previous year.

Electricity generation from coal decreased in all regions of the country except for the Northeast, where there is very little coal generation to begin with. Natural gas generation increased from the previous year in all parts of the country except for the West, which saw a 2.7% decrease compared to May 2015. This decrease in natural gas generation occurred because the West, and more specifically the Northwest part of the country, saw a large increase in hydroelectric generation in May 2016 due to melting snow from warmer spring temperatures.

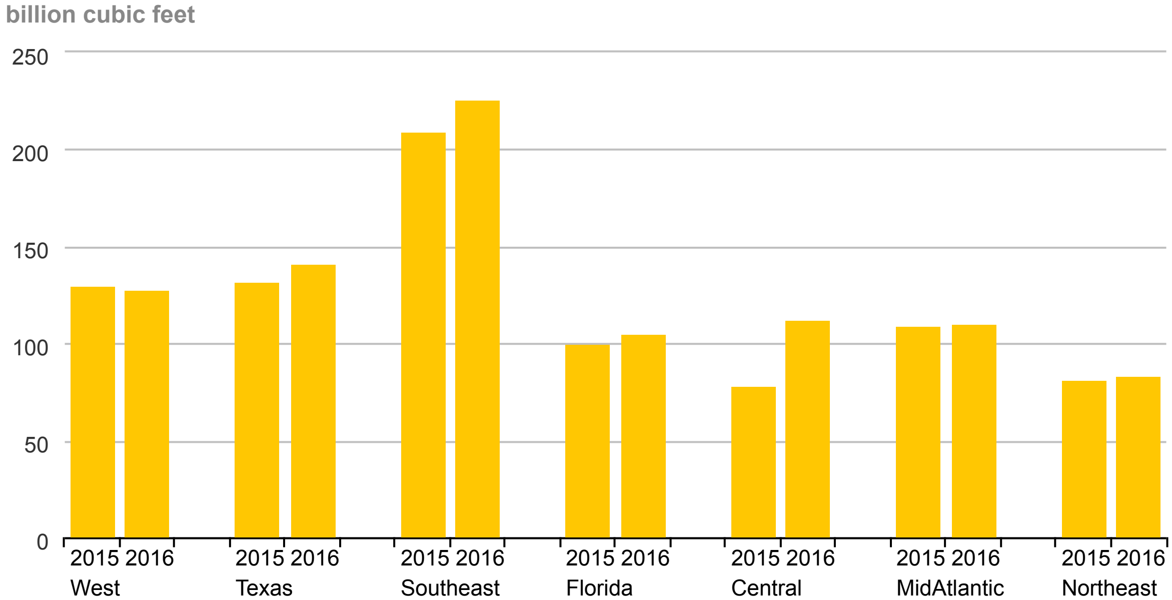
Fossil fuel consumption by region

Coal consumption by type, May



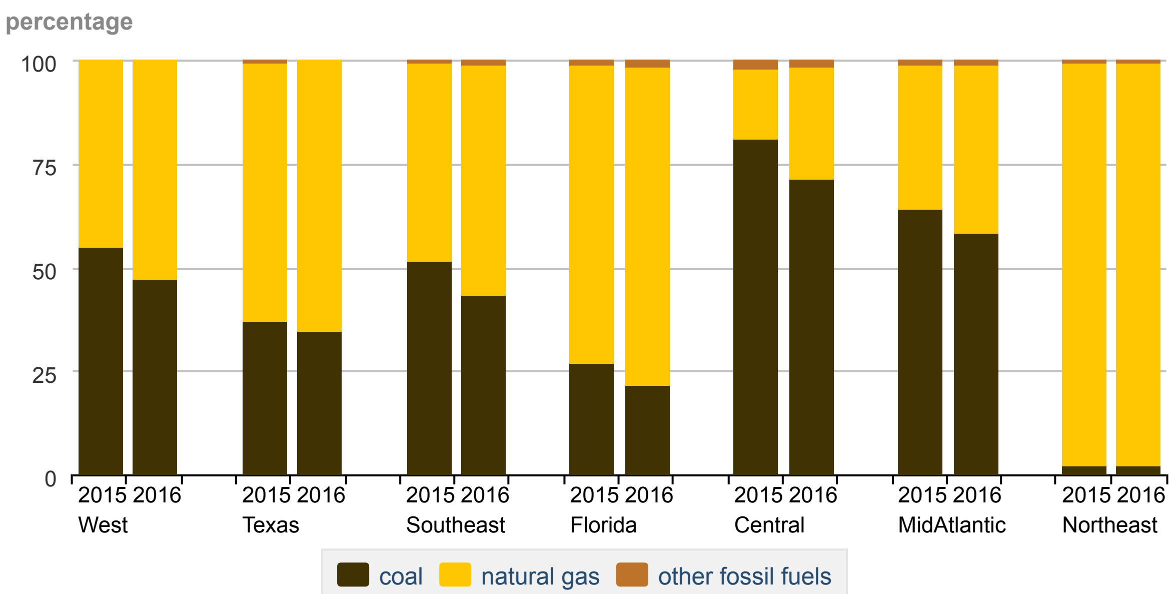
Source: U.S. Energy Information Administration

Natural gas consumption, May



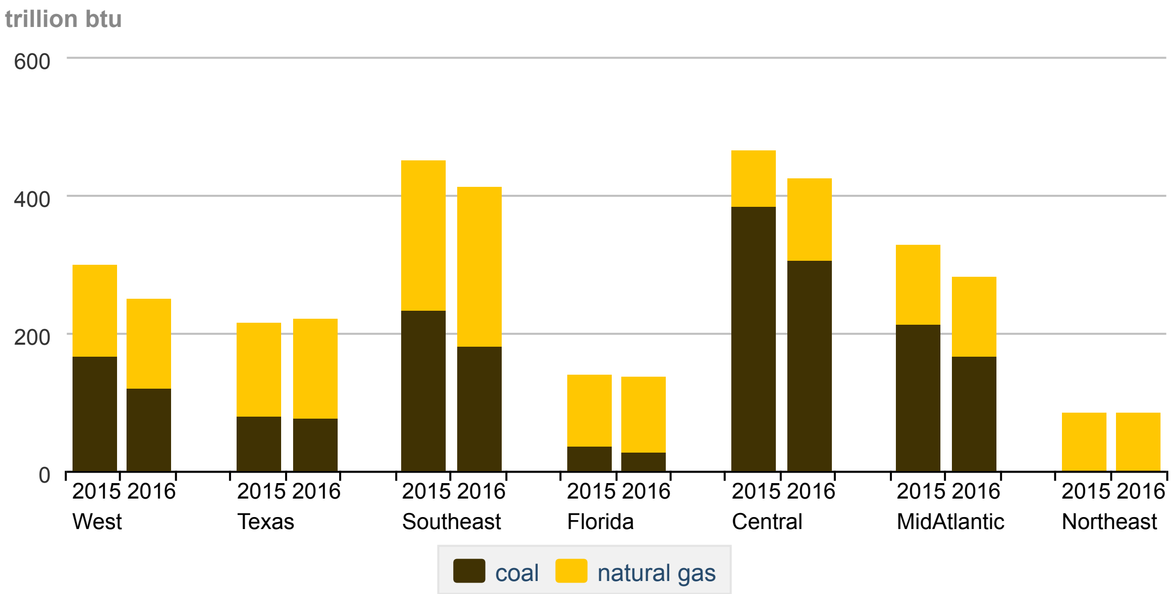
Source: U.S. Energy Information Administration

Share of fossil fuel consumption (percentage), May

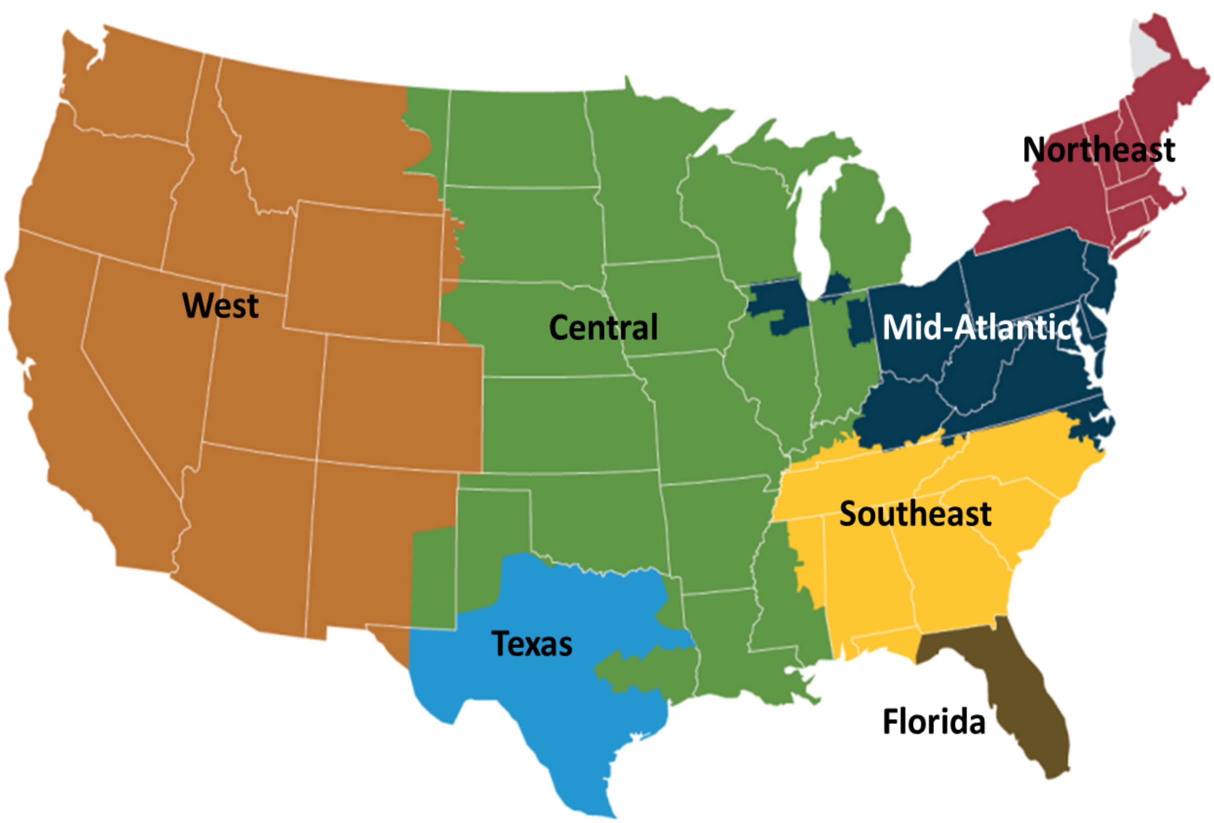


Source: U.S. Energy Information Administration

Coal and natural gas consumption by energy content, May



Source: U.S. Energy Information Administration



The chart above compares coal consumption in May 2015 and May 2016 by region and shows that the change in coal consumption mirrored the change in electricity generation from coal.

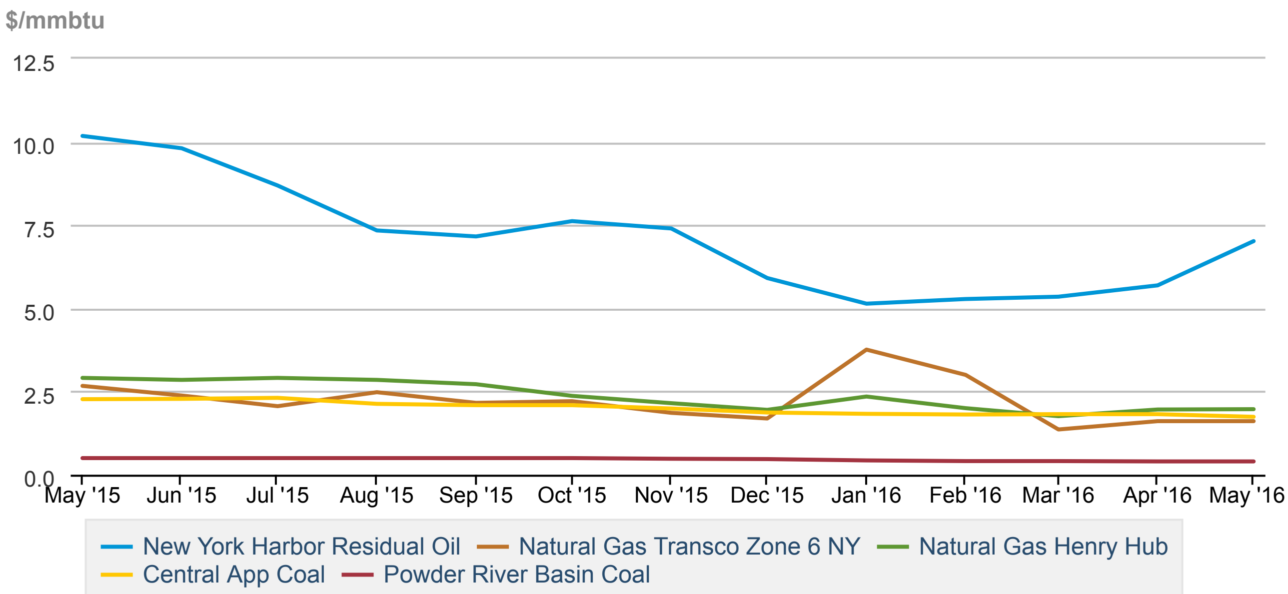
The second tab compares natural gas consumption by region and shows that changes in natural gas consumption from the previous May were similar to the changes in electricity generation from natural gas over the same period.

The third tab presents the change in the relative share of fossil fuel consumption by fuel type on a percentage basis, calculated using equivalent energy content (Btu). This highlights changes in the relative market shares of coal, natural gas, and petroleum. In May 2016, the share of natural gas consumption increased in almost all regions of the country at the expense of coal consumption compared to the previous year. The only outlier was in the Northeast, where the very small share of coal consumption increased slightly at the expense of natural gas compared to the previous May.

The fourth tab presents the change in coal and natural gas consumption on an energy content basis by region. The changes in total coal and natural gas consumption were similar to the changes seen in total coal and natural gas net generation in each region.

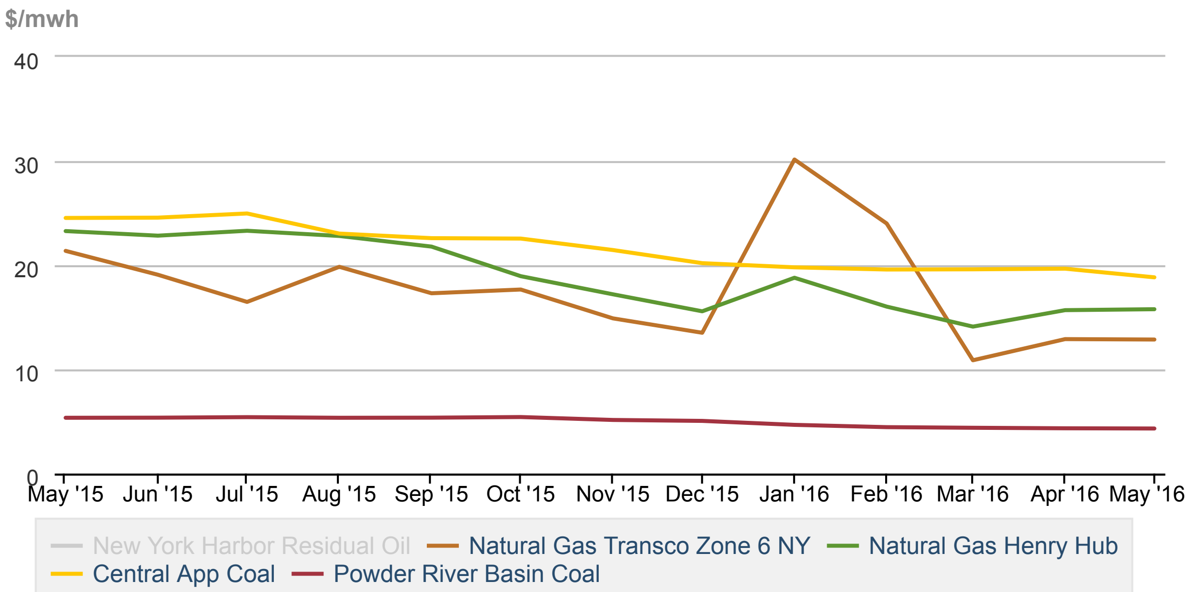
Fossil fuel prices

Average fossil fuel spot prices ($/mmBtu), May 2015 – May 2016



Source: U.S. Energy Information Administration derived from Bloomberg Energy

Average fossil fuel spot prices ($/MWh), May 2015 – May 2016



Source: U.S. Energy Information Administration derived from Bloomberg Energy

To gain some insight into the changing pattern of consumption of fossil fuels over the past year, we look at relative monthly average fuel prices. A common way to compare fuel prices is on an equivalent $/MMBtu basis as shown in the chart above. The average price of natural gas at Henry Hub remained relatively unchanged from the previous month, only going from $1.96/MMBtu in April 2016 to $1.97/MMBtu in May 2016. The natural gas price for New York City (Transco Zone 6 NY) remained unchanged from the previous month, and was $1.61/MMBtu in both April and May 2016.

The New York Harbor residual oil price increased from the previous month, going from $5.69/MMBtu in April 2016 to $7.02/MMBtu in May 2016. Regardless, oil used as a fuel for electricity generation is almost always priced out of the market.

A fuel price comparison based on equivalent energy content ($/MMBtu) does not reflect differences in energy conversion efficiency (heat rate) among different types of generators. Gas-fired combined-cycle units tend to be more efficient than coal-fired steam units. The second tab shows coal and natural gas prices on an equivalent energy content and efficiency basis. For the seventeenth consecutive month, the price of natural gas at Henry Hub was below the price of Central Appalachian coal on a $/MWh basis. The spread between the two prices decreased in May 2016, mainly due to the decrease in the price of Central Appalachian coal. The price of natural gas at New York City on a $/MWh basis was below the price of Central Appalachian coal for a third consecutive month, and the spread between the two prices decreased due to the decrease in the price of Central Appalachian coal.

The conversion shown in this chart is done for illustrative purposes only. The competition between coal and natural gas to produce electricity is more complex. It involves delivered prices and emission costs, the terms of fuel supply contracts, and the workings of fuel markets.

Regional Wholesale Markets: May 2016

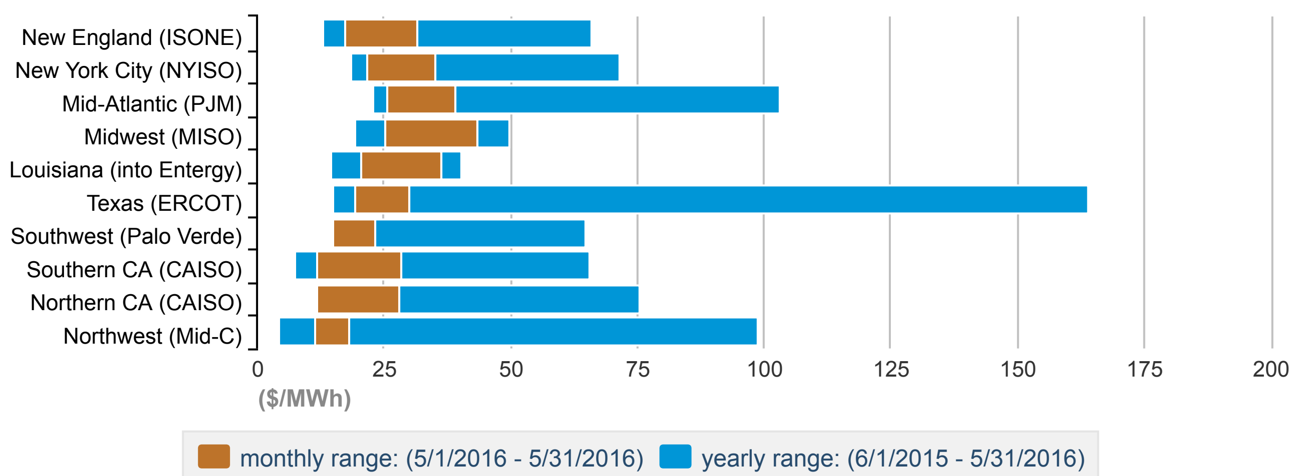
The United States has many regional wholesale electricity markets. Below we look at monthly and annual ranges of on-peak, daily wholesale prices at selected pricing locations and daily peak demand for selected electricity systems in the Nation. The range of daily prices and demand data is shown for the report month and for the year ending with the report month.

Prices and demand are shown for six Regional Transmission Operator (RTO) markets: ISO New England (ISO-NE), New York ISO (NYISO), PJM Interconnection (PJM), Midwest ISO (MISO), Electric Reliability Council of Texas (ERCOT), and two locations in the California ISO (CAISO). Also shown are wholesale prices at trading hubs in Louisiana (into Entergy), Southwest (Palo Verde) and Northwest (Mid-Columbia). In addition to the RTO systems, peak demand is also shown for the Southern Company, Progress Florida, Tucson Electric, and the Bonneville Power Authority (BPA). Refer to the map tabs for the locations of the electricity and natural gas pricing hubs and the electric systems for which peak demand ranges are shown.

In the second tab immediately below, we show monthly and annual ranges of on-peak, daily wholesale natural gas prices at selected pricing locations in the United States. The range of daily natural gas prices is shown for the same month and year as the electricity price range chart. Wholesale electricity prices are closely tied to wholesale natural gas prices in all but the center of the country. Therefore, one can often explain current wholesale electricity prices by looking at what is happening with natural gas prices.

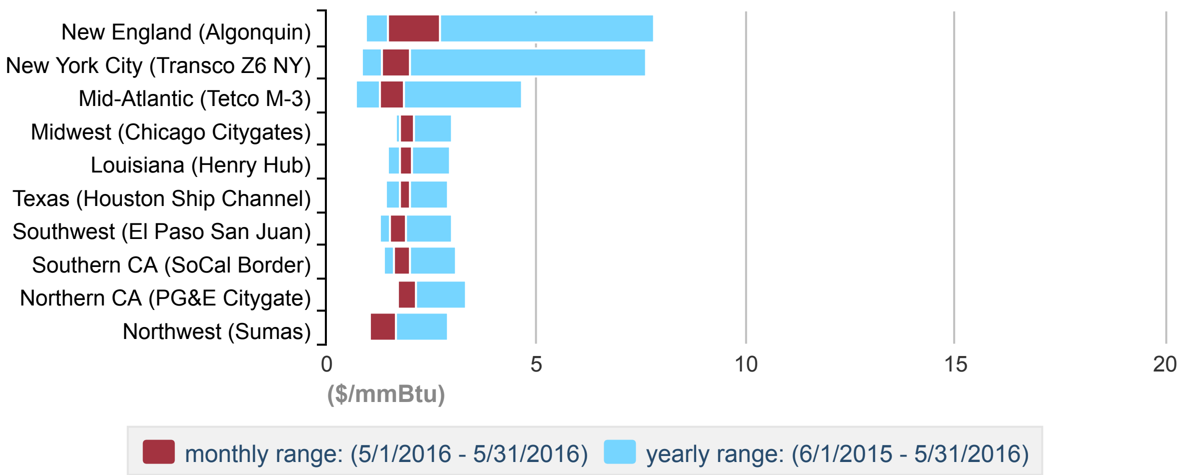
Wholesale prices

Monthly and annual range of wholesale electricity prices for selected regional trading hubs, May 2016



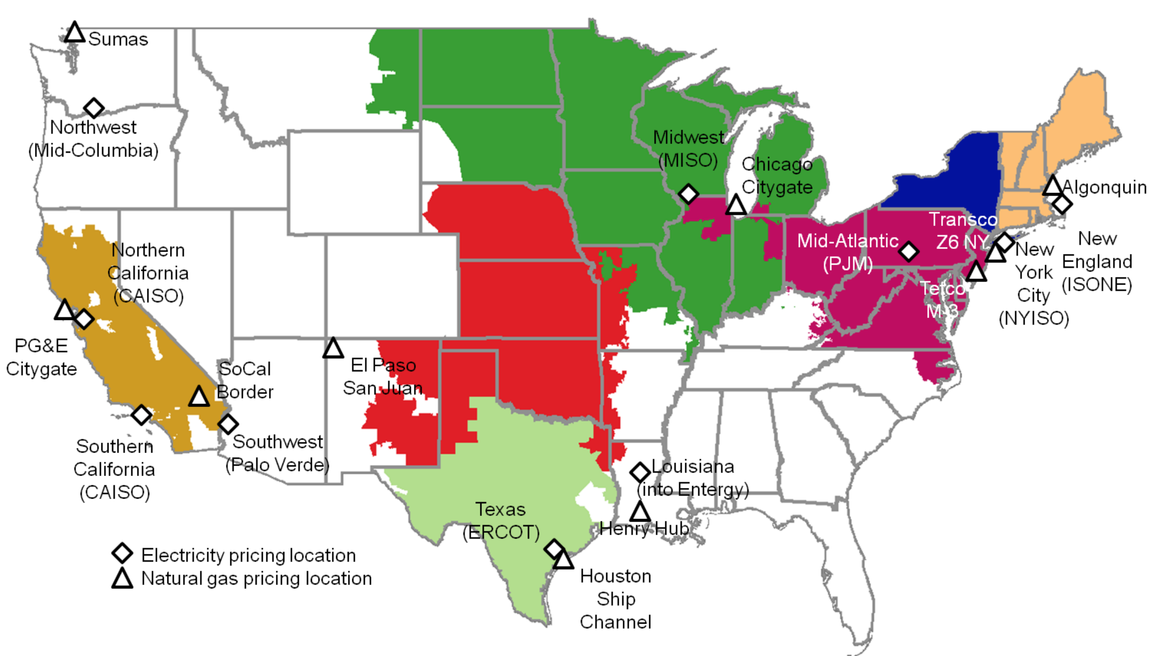
Source: U.S Energy Information Administration based on SNL Energy

Monthly and annual range of wholesale natural gas prices for selected regional trading hubs, May 2016



Source: U.S Energy Information Administration based on SNL Energy

Selected Wholesale Electricity and Natural Gas Pricing Locations



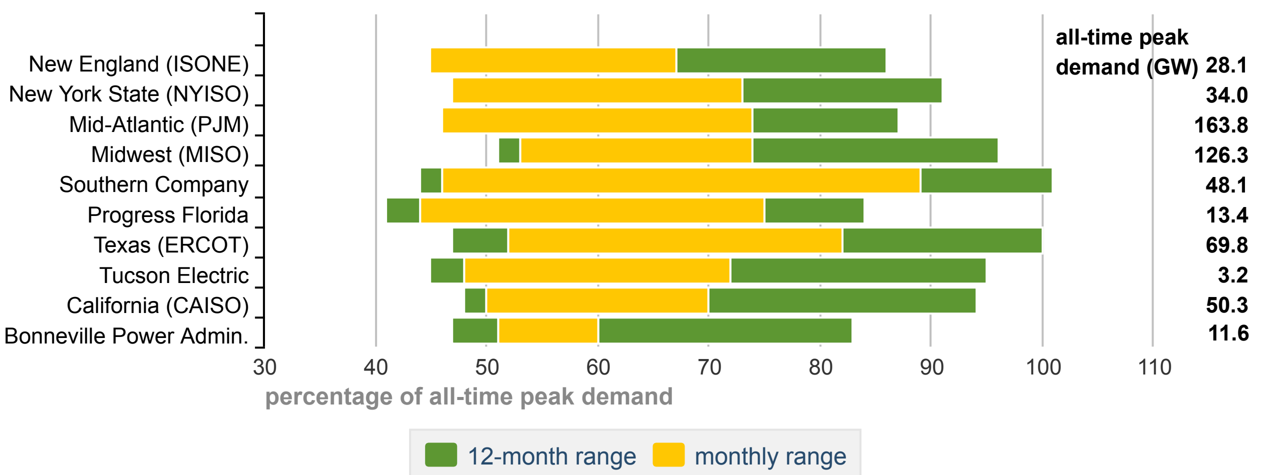
Source: U.S. Energy Information Administration based on Ventyx Energy Velocity Suite.

Wholesale electricity prices in May remained on the lower end of the 12-month range despite summer-like temperatures and daily peak demand levels in many areas of the country towards the end of the month. This was due in large part to very low natural gas prices in all regions. The highest daily natural gas price for the month reached only $2.70/MMBtu at Algonquin in the Boston area. This is less than half the daily peak price recorded at Algonquin in April. Prices at all other hubs remained below $2.17/MMBtu during the month, with five hubs never peaking above $2/MMBtu. The lowest wholesale natural gas price for the month occurred in the Northwest, where prices at Sumas bottomed out at $1.06/MMBtu on May 13.

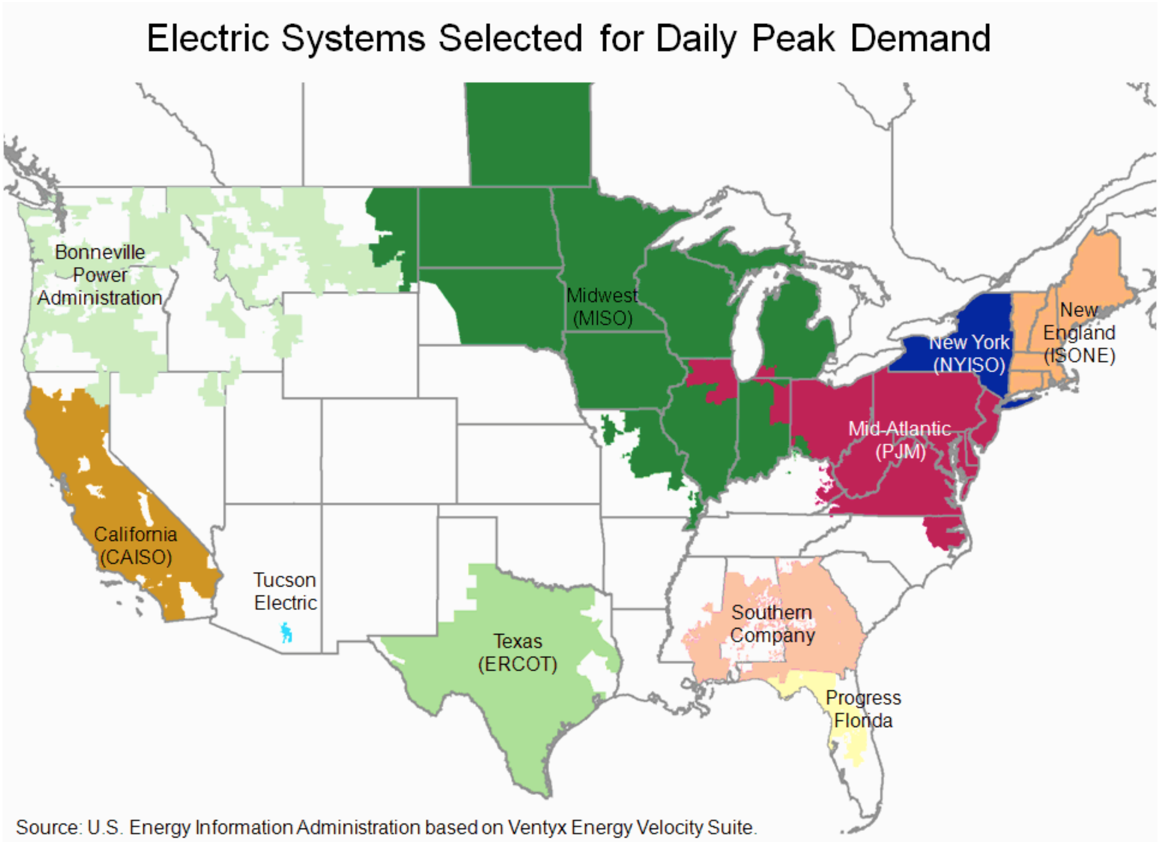
Wholesale electricity prices were highest in the Midwest (MISO), which is not often the case, peaking at $43.56/MWh on May 26. The highest price at this hub over the last 12 months was just under $50/MWh. Prices at all other hubs remained below $40/MWh during the month. The lowest electricity price for the month, as with natural gas prices, was found in the Northwest, where prices bottomed out at $11.50/MWh at Mid-C. Besides the extremely low natural gas prices during May, electricity prices in the Northwest tend to be very low in the spring due to high levels of hydroelectric production from melting snow. This spring has been very warm in the Northwest, which pulled peak hydroelectric production forward into April as the snowpack melted earlier than if temperatures had been cooler. But runoff levels remained high in the beginning of May before dropping precipitously through the month as snowpack levels declined.

Electricity system daily peak demand

Monthly and annual range of selected electricity system daily peak demand, May 2016

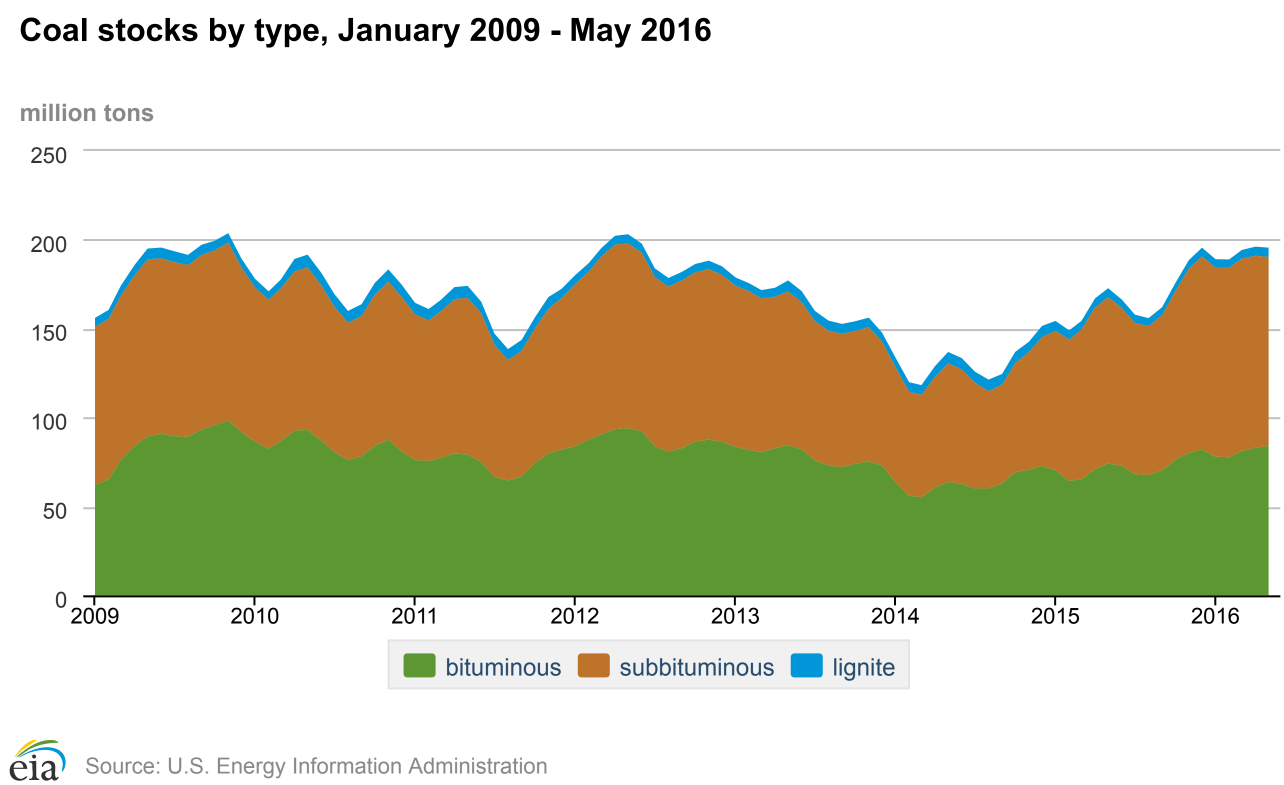


Source: U.S Energy Information Administration based on Ventyx Energy Velocity Suite and utility OASIS websites



Electricity system daily peak demand in May ranged widely within most regions as spring turned to summer. 12-month daily peak demand lows were approached or set in New England (ISONE) on May 21, New York State (NYISO) on May 8 and the Mid-Atlantic (PJM) on May 7. These regions also had their highest daily peak demand levels in quite some time. Peak demand reached in New York State (NYISO) on May 31 was the highest since September 17 of last year. New England's (ISONE) May 31 peak demand was its highest since February 15. PJM's May 31 peak demand was its highest since January 20 and MISO's May 31 peak was its highest since January 19.

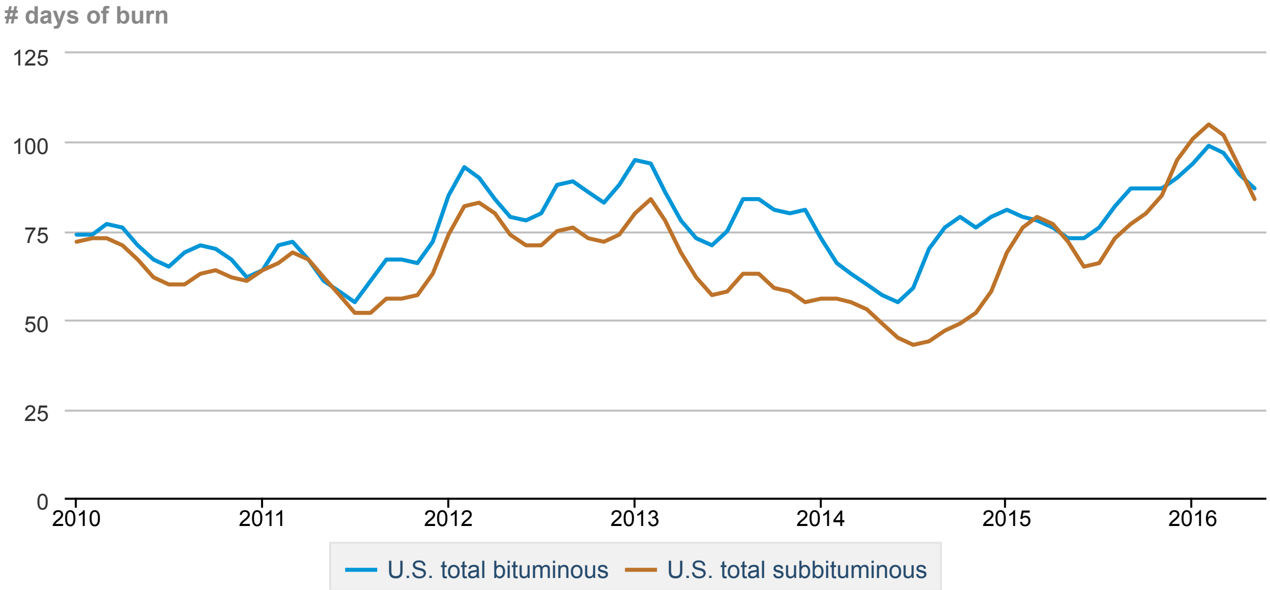
Electric Power Sector Coal Stocks: May 2016



In May, U.S. coal stockpiles decreased slightly to 195 million tons, down 0.3% from the previous month. As a whole, U.S. coal stockpiles are still at very high levels due to the mild winter experienced earlier in the year and also becaue coal continues to lose market share to natural gas in most regions of the country.

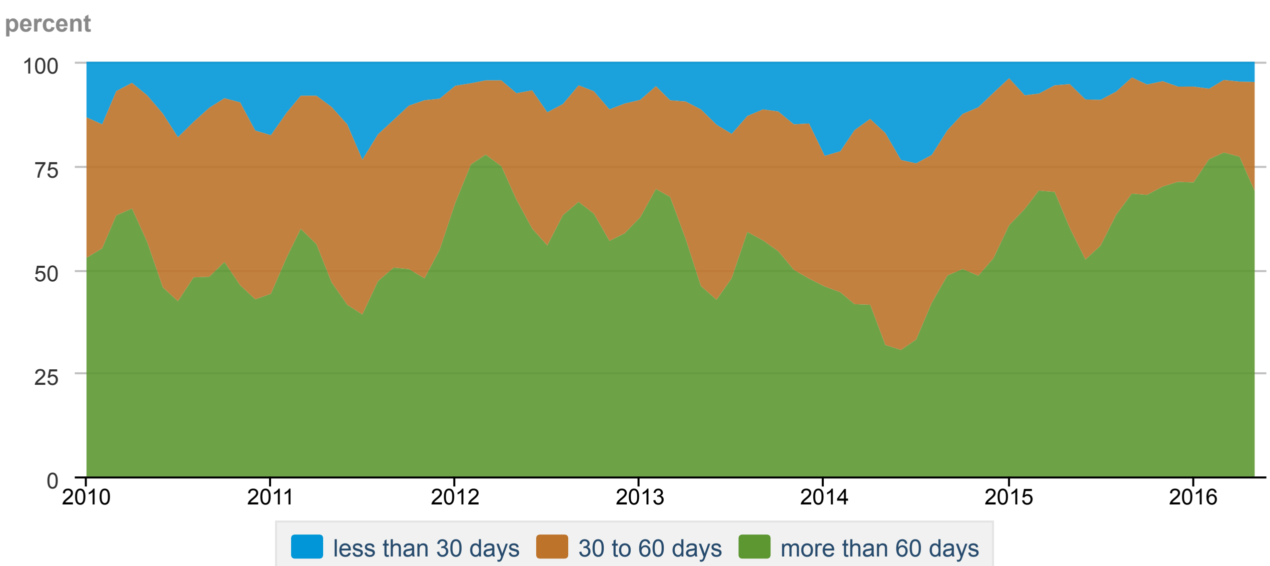
Days of burn

Days of burn by non-lignite coal rank, January 2009 - May 2016



Source: U.S. Energy Information Administration

U.S. non-lignite capacity by days of burn, January 2009 - May 2016



Source: U.S. Energy Information Administration

The average number of days of burn held at electric power plants is a forward-looking estimate of coal supply given a power plant's current stockpile and past consumption patterns. For bituminous units largely located in the eastern United States, the average number of days of burn decreased from 91 days of burn in April to 87 days of forward-looking days of burn in May. For subbituminous units largely located in the western United States, the average number of days of burn decreased, going from 93 days in April to 84 days in May.

Coal stocks and average number of days of burn for non-lignite coal by region (electric power sector)

		May 2016		May 2015			April 2016		
Zone	Coal	Stocks (1000 tons)	Days of Burn	Stocks (1000 tons)	Days of Burn	% Change of Stocks	Stocks (1000 tons)	Days of Burn	% Change of Stocks
Northeast	Bituminous	7,439	115	6,638	84	12.1%	7,641	117	-2.6%
	Subbituminous	171	184	797	242	-78.5%	171	184	0.0%
South	Bituminous	37,894	84	34,738	72	9.1%	37,654	89	0.6%
	Subbituminous	7,959	82	7,066	75	12.6%	7,838	86	1.5%
Midwest	Bituminous	18,853	92	15,727	73	19.9%	18,365	95	2.7%
	Subbituminous	47,382	80	40,939	65	15.7%	46,805	86	1.2%
West	Bituminous	5,861	76	5,544	70	5.7%	5,587	76	4.9%
	Subbituminous	39,169	90	35,064	80	11.7%	41,393	103	-5.4%
U.S. Total	Bituminous	70,047	87	62,648	73	11.8%	69,247	91	1.2%
	Subbituminous	94,681	84	83,866	72	12.9%	96,207	93	-1.6%

Source: U.S. Energy Information Administration

NOTE: Stockpile levels shown above reflect a sample of electric power sector plants, which were used to create the days of burn statistics. These levels will not equal total electric power sector stockpile levels.

Methodology and Documentation

General

The Electricity Monthly Update is prepared by the Electric Power Operations Team, Office of Electricity, Renewables and Uranium Statistics, U.S. Energy Information Administration (EIA), U.S. Department of Energy. Data published in the Electricity Monthly Update are compiled from the following sources: U.S. Energy Information Administration, Form EIA-826,“Monthly Electric Utility Sales and Revenues with State Distributions Report,” U.S. Energy Information Administration, Form EIA-923, "Power Plant Operations Report," fuel spot prices from Bloomberg Energy, electric power prices from SNL Energy, electric system demand data from Ventyx Energy Velocity Suite, and weather data and imagery from the National Oceanic and Atmospheric Administration.

The survey data are collected monthly using multiple-attribute cutoff sampling of power plants and electric retailers for the purpose of estimation for various data elements (generation, stocks, revenue, etc.) for various categories, such as geographic regions. (The data elements and categories are “attributes.”) The nominal sample sizes are: for the Form EIA-826, approximately 450 electric utilities and other energy service providers; for the Form EIA-923, approximately 1900 plants. Regression-based (i.e., “prediction”) methodologies are used to estimate totals from the sample. Essentially complete samples are collected for the Electric Power Monthly (EPM), which includes State-level values. The Electricity Monthly Update is based on an incomplete sample and includes only regional estimates and ranges for state values where applicable. Using ‘prediction,’ it is generally possible to make estimates based on the incomplete EPM sample, and still estimate variances.

For complete documentation on EIA monthly electric data collection and estimation, see the Technical Notes to the *Electric Power Monthly*. Values displayed in the Electric Monthly Update may differ from values published in the Electric Power Monthly due to the additional data collection and data revisions that may occur between the releases of these two publications.

Accessing the data: The data included in most graphics can be downloaded via the "Download the data" icon above the navigation pane.Some missing data are proprietary and non-public.

Key Indicators

The Key Indicators in the table located in the "Highlights" section, are defined below. The current month column includes data for the current month at a national level. The units vary by statistic, but are included in the table. The "% Change from 2010" value is the current month divided by the corresponding month last year (e.g. July 2011 divided by July 2010). This is true for Total Generation, Residential Retail Price, Retail Sales, Degree-Days, Coal Stocks, Coal and Natural Gas Consumption. The Henry Hub current month value is the average weekday price for the current month. The Henry Hub "% Change from 2010" value is the average weekday price of the same month from 2010 divided by the average weekday price of the current month.

Total Net Generation: Reflects the total electric net generation for all reporting sectors as collected via the Form EIA-923.
Residential Retail Price: Reflects the average retail price as collected via the Form EIA-826.
Retail Sales: Reflects the reported volume of electricity delivered as collected via the Form EIA-826.
Degree-Days: Reflects the total population-weighted United States degree-days as reported by the National Oceanic and Atmospheric Administration.
Natural Gas Henry Hub: Reflects the average price of natural gas at Henry Hub for the month. The data are provided by Bloomberg.
Coal Stocks: Reflects the total coal stocks for the Electric Power Sector as collected via the Form EIA-923.
Coal Consumption: Reflects the total coal consumption as collected via the Form EIA-923.
Natural Gas Consumption: Reflects the total natural gas consumption as collected via the Form EIA-923.
Nuclear Outages: Reflects the average daily outage amount for the month as reported by the Nuclear Regulatory Commission's Power Reactor Status Report and the latest net summer capacity data collected on the EIA-860 Annual Generator Report.

Sector Definitions

The Electric Power Sector comprises electricity-only and combined heat and power (CHP) plants within the North American Industrial Classification System 22 category whose primary business is to sell electricity, or electricity and heat, to the public (i.e., electric utility plants and Independent Power Producers (IPPs), including IPP plants that operate as CHPs). The All Sectors totals include the Electric Power Sector and the Commercial and Industrial Sectors (Commercial and Industrial power producers are primarily CHP plants).

Degree Days

Degree-days are relative measurements of outdoor air temperature used as an index for heating and cooling energy requirements. Heating degree-days are the number of degrees that the daily average temperature falls below 65° F. Cooling degree-days are the number of degrees that the daily average temperature rises above 65° F. The daily average temperature is the mean of the maximum and minimum temperatures in a 24-hour period. For example, a weather station recording an average daily temperature of 40° F would report 25 heating degree-days for that day (and 0 cooling degree-days). If a weather station recorded an average daily temperature of 78° F, cooling degree-days for that station would be 13 (and 0 heating degree days).

Per Capita Retail Sales

The per capita retail sales statistics use 2011 population estimates from the U.S. Census Bureau and monthly data collected by the Energy Information Administration. The volume of electricity delivered to end users for all sectors in kilowatthours is divided by the 2011 population estimate for each state.

Composition of Fuel Categories

Net generation statistics are grouped according to regions (see Electricity Monthly Update Explained Section) by generator type and fuel type. Generator type categories include:

Fossil Steam: Steam turbines powered by the combustion of fossil fuels
Combined Cycle: Combined cycle generation powered by natural gas, petroluem, landfill gas, or other miscellaneous energy sources
Other Fossil: Simple cycle gas turbines, internal combustion turbines, and other fossil-powered technology
Nuclear Steam: Steam turbines at operating nuclear power plants
Hydroelectric: Conventional hydroelectric turbines
Wind: Wind turbines
Other renewables: All other generation from renewable sources such as geothermal, solar, or biomass
Other: Any other generation technology, including hydroelectric pumped storage

Generation statistics are also displayed by fuel type. These include:

Coal: all generation associated with the consumption of coal
Natural Gas: all generation associated with the consumption of natural gas
Nuclear: all generation associated with nuclear power plants
Hydroelectric: all generation associated with conventional hydroelectric turbines
Other Renewable: all generation associated with wind, solar, biomass, and geothermal energy sources
Other Fossil: all generation associated with petroleum products and fossil-dervied fuels
Other: all other energy sources including waste heat, hydroelectric pumped storage, other reported sources

Relative Fossil Fuel Prices

Relative fossil fuel prices are daily averages of fossil fuel prices by month, displayed in dollars per million British thermal units as well as adjusted for operating efficiency at electric power plants to convert to dollars per megawatthour. Average national heat rates for typical operating units for 2010 were used to convert relative fossil fuel prices.

Average Days of Burn

Average Days of Burn is defined as the average number of days remaining until coal stocks reach zero if no further deliveries of coal are made. These data have been calculated using only the population of coal plants present in the monthly Form EIA-923. This includes 1) coal plants that have generators with a primary fuel of bituminous coal (including anthracite) or subbituminous, and 2) are in the Electric Power Sector (as defined in the above "Sector definitions"). Excluded are plants with a primary fuel of lignite or waste coal, mine mouth plants, and out-of-service plants. Coal storage terminals and the related plants that they serve are aggregated into one entity for the calculation of Average Days of Burn, as are plants that share stockpiles.

Average Days of Burn is computed as follows: End of month stocks for the current (data) month, divided by the average burn per day. Average Burn per Day is the average of the three previous years' consumption as reported on the Form EIA-923.

These data are displayed by coal rank and by zone. Each zone has been formed by combining the following Census Divisions:

- Northeast — New England, Middle Atlantic
- South — South Atlantic, East South Central
- Midwest — West North Central, East North Central
- West — Mountain, West South Central, Pacific Contiguous

Coal Stocks vs. Days of Burn Stocks

The coal stocks data presented at the top of the Fossil Fuel Stocks section (“Coal Stocks”) will differ from the coal stocks presented in the Days of Burn section (“DOB Stocks”) at the bottom of the Fossil Fuel Stocks section. This occurs because Coal Stocks include the entire population of coal plants that report on both the annual and monthly Form EIA-923. The DOB Stocks only include coal plants that report on the monthly Form EIA-923 and have a primary fuel of bituminous (including anthracite) or subbituminous as reported on the Form EIA-860.