WORKING GROUP PRESENTATION FOR DISCUSSION PURPOSES.
DO NOT QUOTE OR CITE MODELING ASSUMPTIONS AND INPUTS ARE SUBJECT TO CHANGE.

AEO2019 1st Coal Working Group Meeting

Coal and Uranium Analysis Team

May 17, 2018 | Washington, D.C.

Roll Call – AEO2019 1st Coal Working Group

Last Name	First Nan	Organization	Attendir	In Perso	WebEx
Adams	Greg	EIA	X	X	
Benevidas	Frank	Alliance Energy	X		X
Benitez	Jose'	EVA	X	X	
Daniels	David	EIA	X	X	
Diefenderfer	Jim	EIA	X	X	
Digiantommaso	Jen	OCFO	X		X
Evans	Carolyn	Norfolk Southern	X		X
Eyster	Jerry	GE	X		X
Fisher	Brian	EPA	X		X
Fritsch	David	EIA	X	X	
Graeter	Philip	EVA	X		X
Heller	Jamie	Hellerworx	X		X
Herndon	Whitney	Rhodium	X		X
Hodge	Tyler	EIA	X	X	
Huetteman	Thaddeus	EIA	X	X	
Khair	Lauren	NRECA	X		X
Kislear	Jordan	DOE	X	X	
Kuester	Catie	Union Pacific	X		X
Kwon	Augustine	EIA	X	X	
Leitman	Michael	NRECA	X		X
Lundgren	Carl	MSHA	X		X
Martin	Laura	EIA	X	X	
Mead	Ian	EIA	X	X	
Medine	Emily	EVA	X		X
Moxness	Greg	DOL	X		X
Namovicz	Christopher	EIA	X	X	
Ondrich	Naomi	DOL	X		X
Rockwell	Joshua	osmre	X		X
Schultz	Robert	LEENA Laboratories	X		X
Wood	Frances	On Location	X		X
Wos	Thomas	Tri-State	X		X
Zelek	Charles	NETL	X		X

Agenda

- Overview of AEO2019 process
- Review of AEO2018 assumptions and projections
  - Legislative and regulatory review
  - 3 key assumptions
  - 3 key industry trends
  - Summary of results for coal capacity, generation, disposition, regions, labor, and exports
- Model updates and improvements for AEO2019 and beyond
- Q&A

Overview of Annual Energy Outlook 2019 (AEO2019)

- AEO2019 will be a limited release
  - Flip-book will be published
  - Only core side cases will be run
    - Reference
    - High/Low Oil & Gas Resource Technology
    - High/Low Oil Price
    - High/Low Economic Growth
  - No Issues in Focus articles or related side cases will be published
  - Assumptions documentation will be updated
- 2nd working group session will be conducted in late summer
- Publication is scheduled for January 2019 (estimated)

AEO2018 Reference case reflects current laws and regulations

- EPA's Clean Power Plan (CPP) not included in AEO2018 Reference case
  - Reference and core side cases including the CPP are available in the AEO data browser
  - All cases include EPA's New Source Performance Standards limiting CO2 emissions from new plants
  - A 3% adder is applied to the cost of capital for new coal units or upgrades to existing units without maximum sequestration options (90% removal) included to account for risk of future tightening of CO2 emissions standards and other policies affecting coal
- EPA's Cross State Air Pollution Rule (CSAPR) and Mercury and Air Toxics Standards are included in the Reference case
- Other EPA regulations assume compliance is reflected in survey Form EIA-860 filings as each plant takes action to comply
  - Regional Haze compliance follows from State Implementation Plans due 7/31/21 with implementation by 2028 (EPA announced it is revisiting the 2017 revision)
  - EPA had projected minimal coal retirements from previously-finalized Coal Combustion Residuals, Cooling Water Intakes, and Effluent Limitation Guidelines
  - Effluent Limitation Guidelines for Best Available Technology (BAT) are under review by EPA
  - The 2015 Coal Combustion Residual regulations are also under review by EPA

State-level programs are also included in the AEO2018 Reference case

- California
  - Recently signed state law under AB 398 Global Warming Solutions Act requires statewide greenhouse gas emissions to return to the 1990 level by 2020 and be 40% below the 1990 level by 2030
  - Cap-and-trade program under AB 32
  - State law under SB-1368 that prohibits CA utilities from entering into long-term financial commitments for base load generation, unless in compliance with the CO2 emissions performance standard of 1,100 lbs/MWh
    - Reduce firm imports to represent expiration of contracts with the Four Corners, Navajo, Reid Gardner, San Juan, and Boardman plants and retire Intermountain in 2025
    - Adjust carbon emission rate for firm imports in accordance with the expiration of contracts
- The Northeast's Regional Greenhouse Gas Initiative (RGGI) program
- Renewable Portfolio Standard (RPS) programs

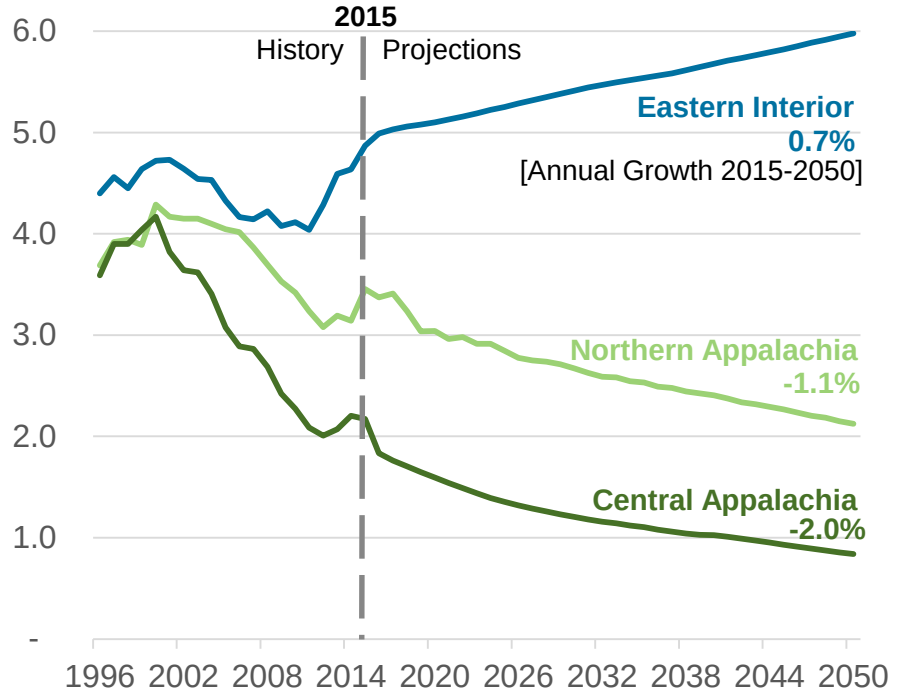
Limited pending regulatory changes applicable to coal mining in the Reference case

- Coal excise tax rates for the Black Lung Disability Trust Fund are scheduled to decline January 1, 2019 From $1.25 to $0.50 per ton for underground, and from $0.55 to $0.25 for surface-mined coal (not applicable to lignite coal and coal intended for export)

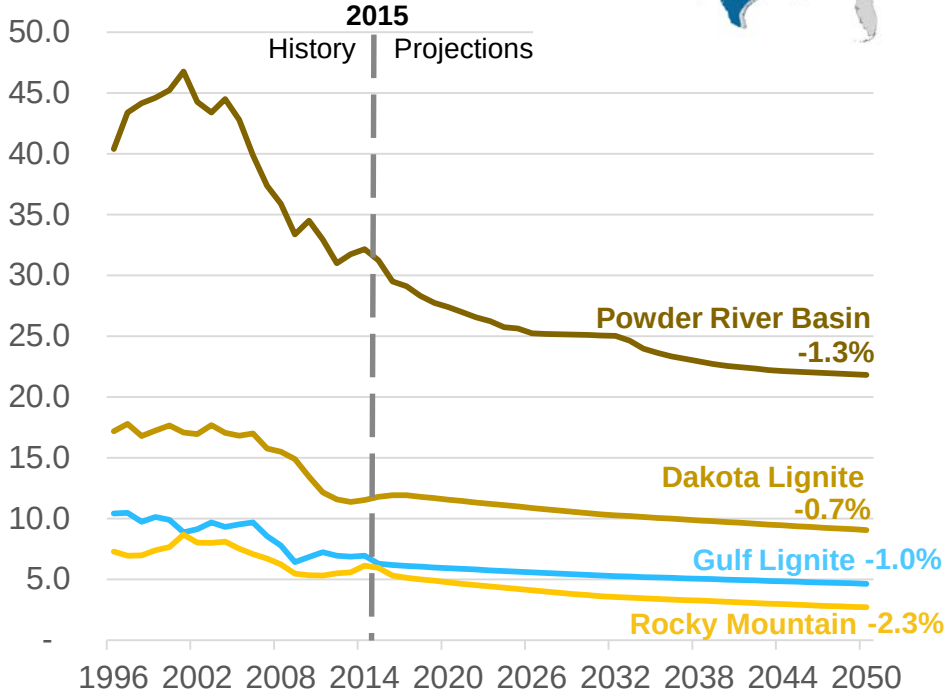
- Other pending federal regulatory actions affecting coal mining are under review and were not included in the Reference case
  - Office of Surface Mining's Stream Protection Rule was nullified and formal programmatic consultation reinitiated
  - Dept. of Interior's Royalty Policy Committee expressed no recommended changes for coal leasing at its Feb. 2018 meeting and continues to evaluate recommendations for determining fair market value for third party transactions and the bonus bid payment schedule
  - Waters of the U.S. (WOTUS) delayed 2 years to February 2020; EPA proposing rule to change definition
  - U.S. District Court (Montana) ruling that Interior update Resource Management Plans (RMPs) for the Powder River Basin to properly account for climate change from leasing of coal and other fossil fuels could have implications for federal coal leasing the region

Coal productivities projected to continue declining with the exception of Eastern Interior

Major Eastern Producing Regions
Short Tons per Miner Hour



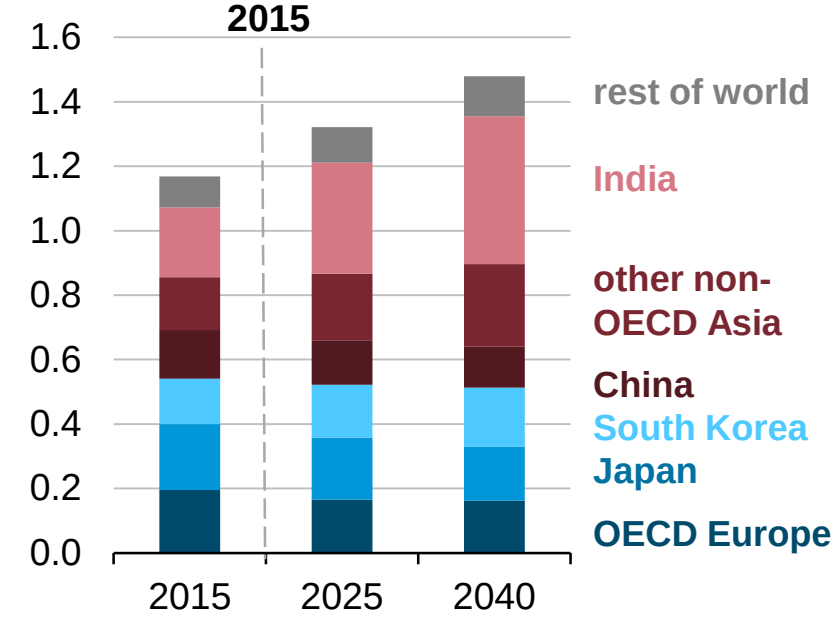
Major Western Producing Regions
Short Tons per Miner Hour



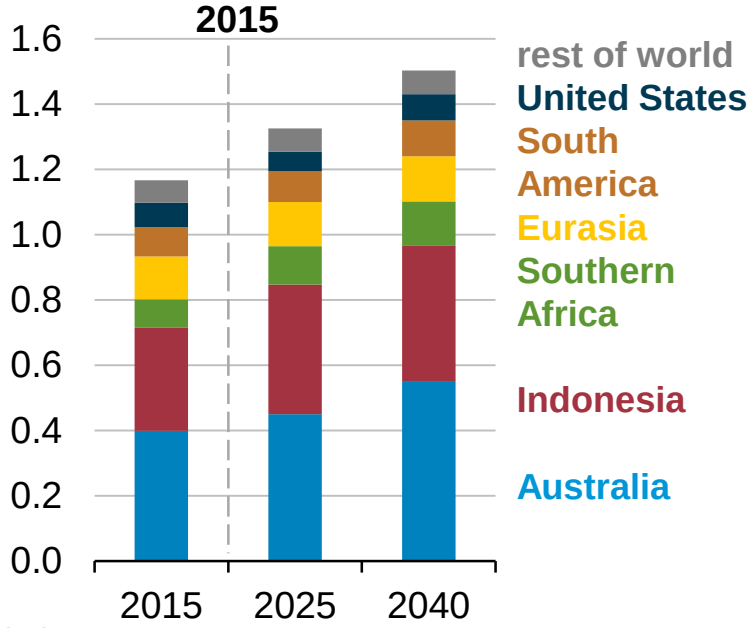
Source: U.S. Energy Information Administration, AEO2018 National Energy Modeling System run REF2018.D1213A.

International seaborne coal trade projected to increase 30% (350 million short tons) in IEO2017 (2015-2040)

Coal imports
billion short tons

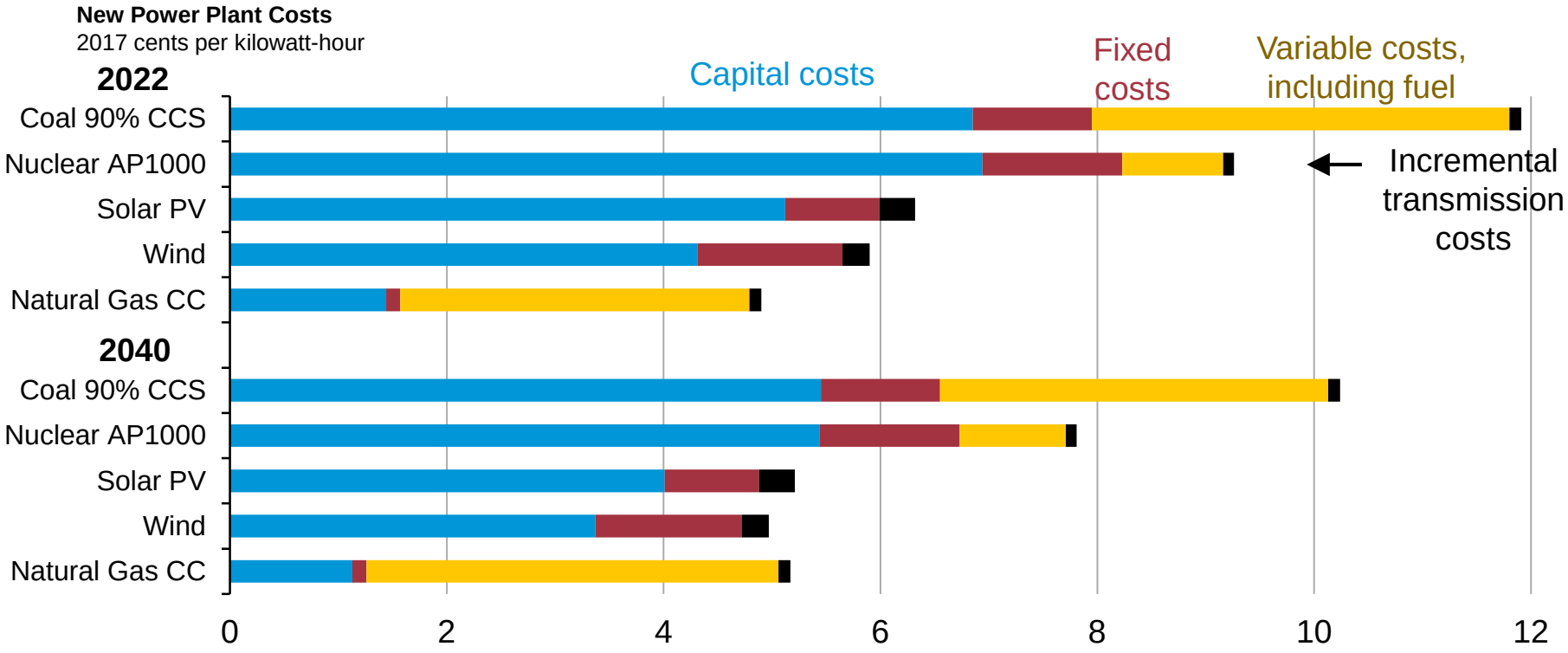


Coal exports
billion short tons



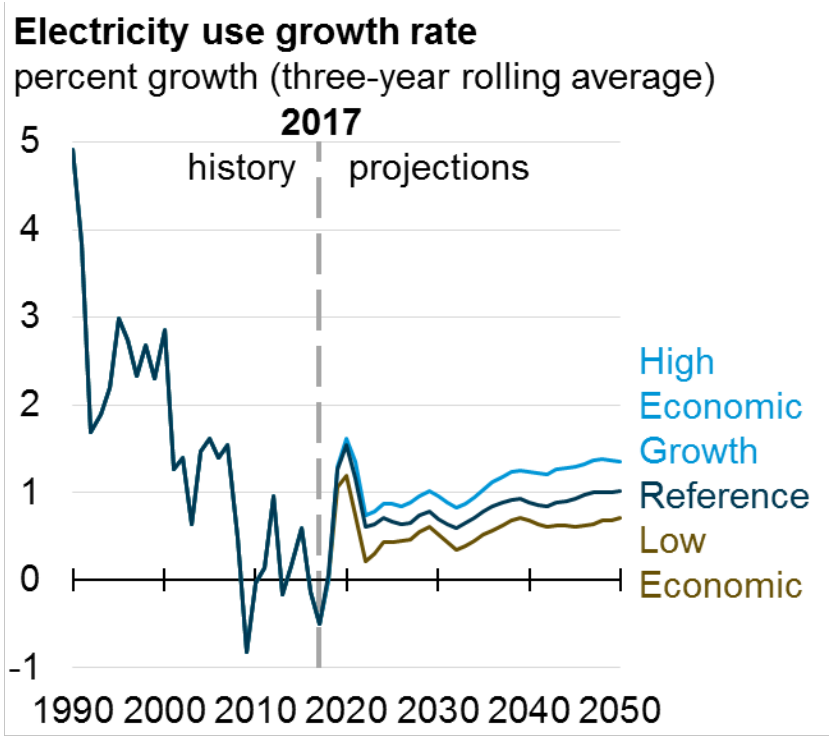
Source: U.S. Energy Information Administration, International Energy Outlook 2017

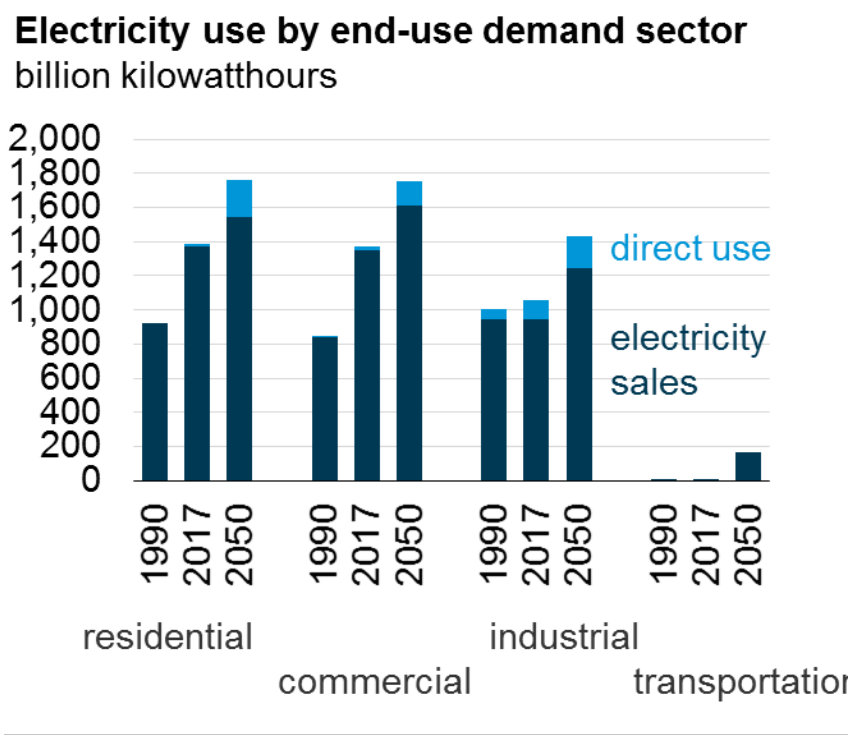
Relatively high levelized cost of electricity for coal prohibits the addition of coal in any case evaluated in AEO2018



Source: "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the AEO2018", March 2018, Excerpted from Table 1b (2022) and Table B1b (2040)

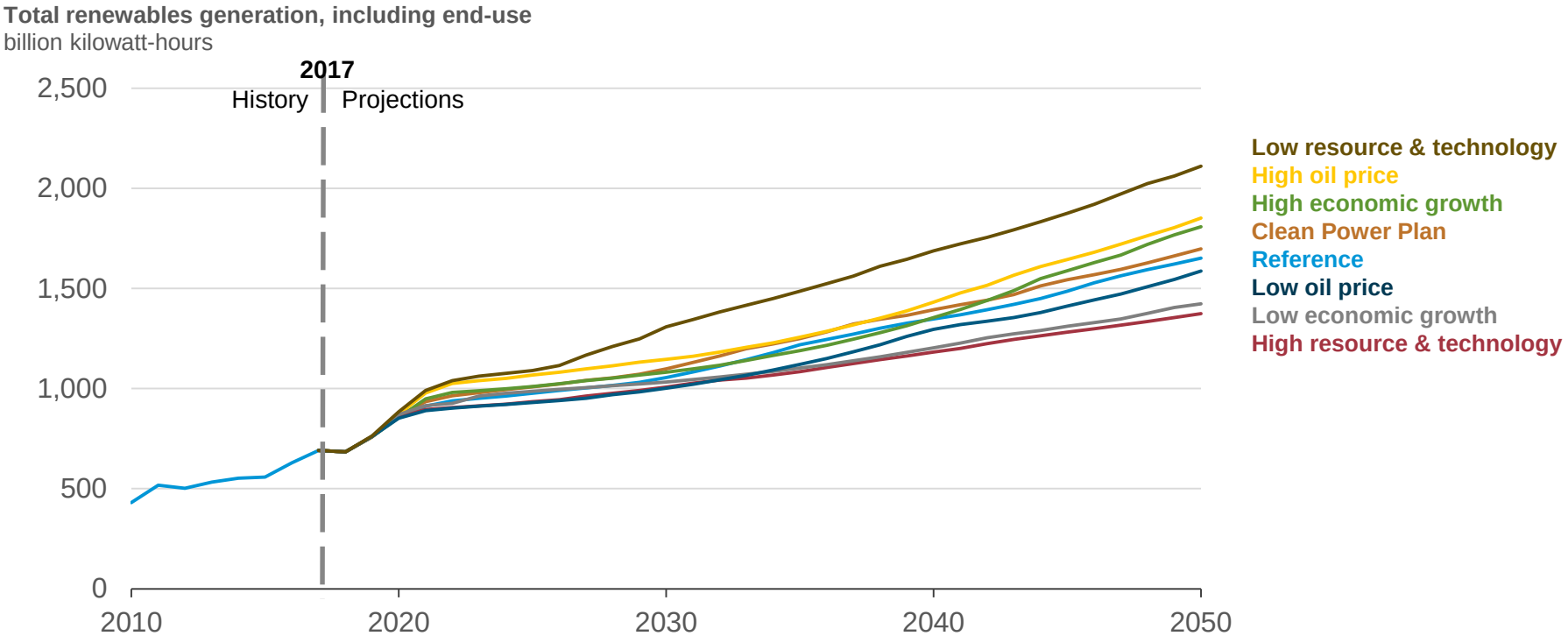
After decades of slowing growth, electricity consumption is expected to grow gradually through 2050





Source: U.S. Energy Information Administration, Annual Energy Outlook 2018.

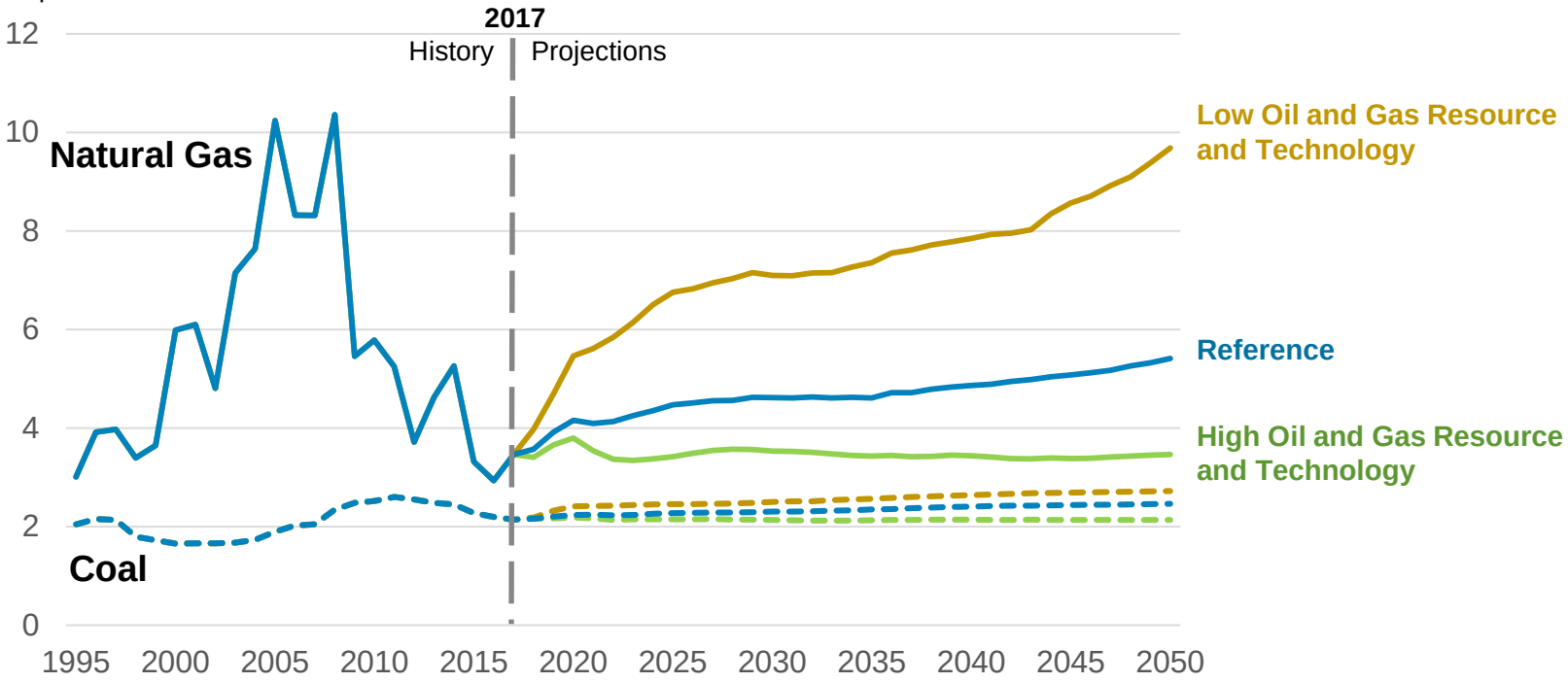
Increasing cost competitiveness of renewables leads to growth in generation even with projection for low electricity demand and low natural gas prices



Source: ref2018.1213a, highmacro.1213a, highrt.1213a, lowprice.1213a, ref_cpp.1213a, highprice.1220a, lowmacro.1213a, lowrt.1213a

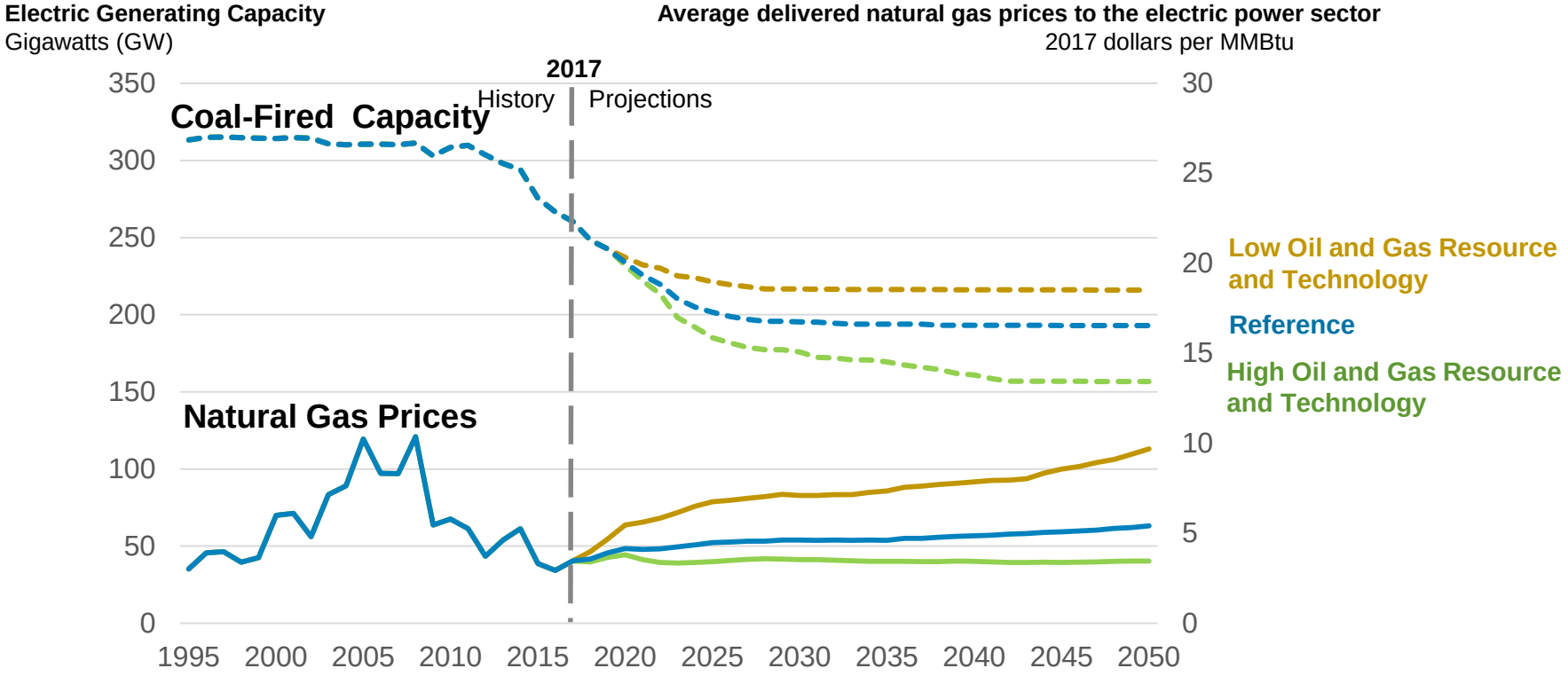
Average delivered coal and natural gas prices to the electric power sector indicate limited competitive opportunity for coal

Average delivered fuel prices to the electric power sector
2017 dollars per MMBtu



Source: U.S. Energy Information Administration, AEO2018 National Energy Modeling System run REF2018.D1213a, highrt.1213a, and lowrt.1213a.

Generating capacity decreases through 2030 in all AEO side cases and is sensitive to the projection for natural gas prices

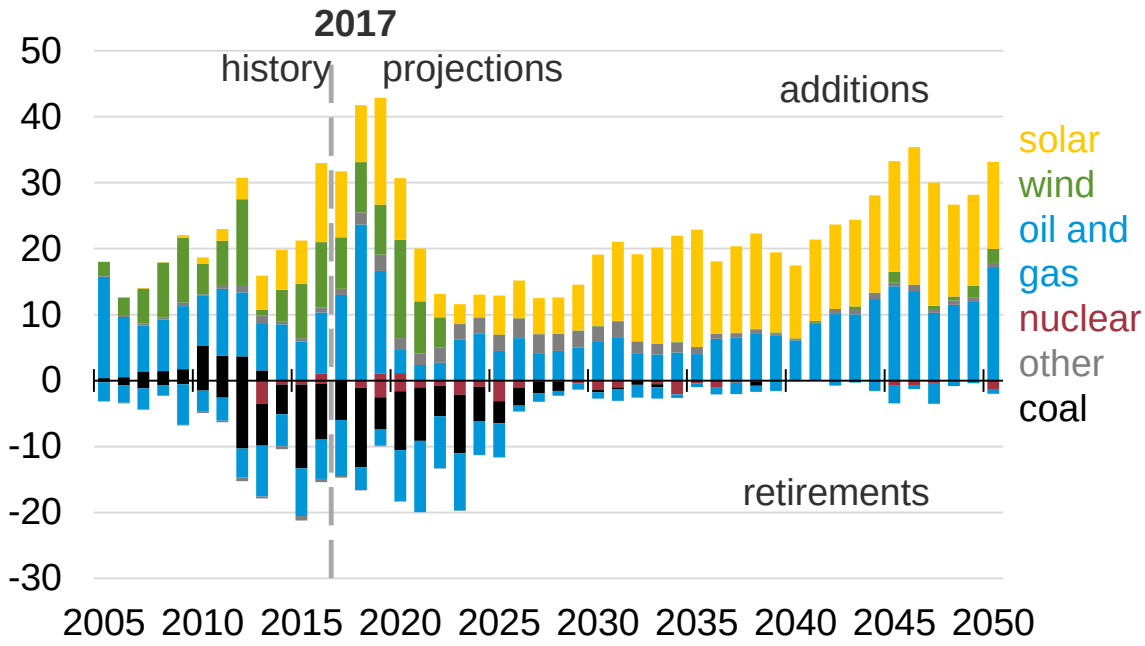


Source: U.S. Energy Information Administration, AEO2018 National Energy Modeling System run REF2018.D1213a, highrt.1213a, and lowrt.1213a.

Economics and policy drive changes to electric generation capacity

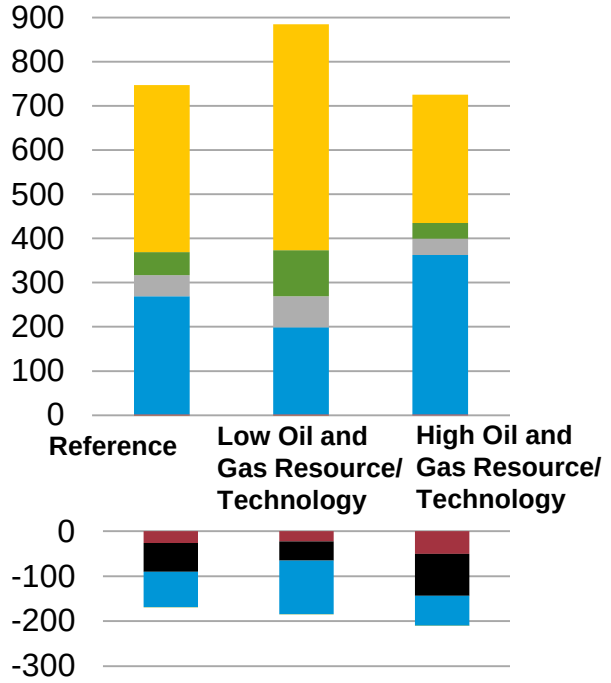
Annual electricity generating capacity additions and retirements (Reference case)

gigawatts



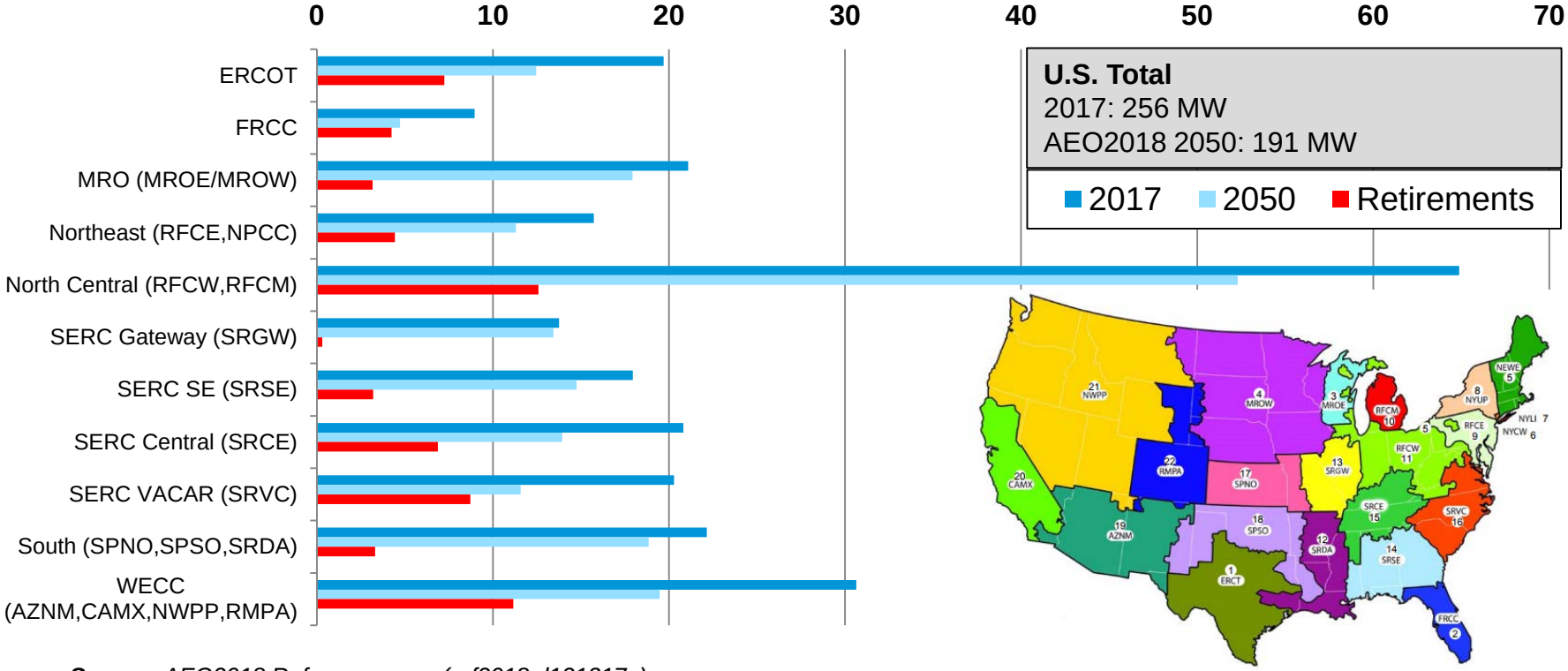
Cumulative generating capacity additions and retirements (2018-50)

gigawatts



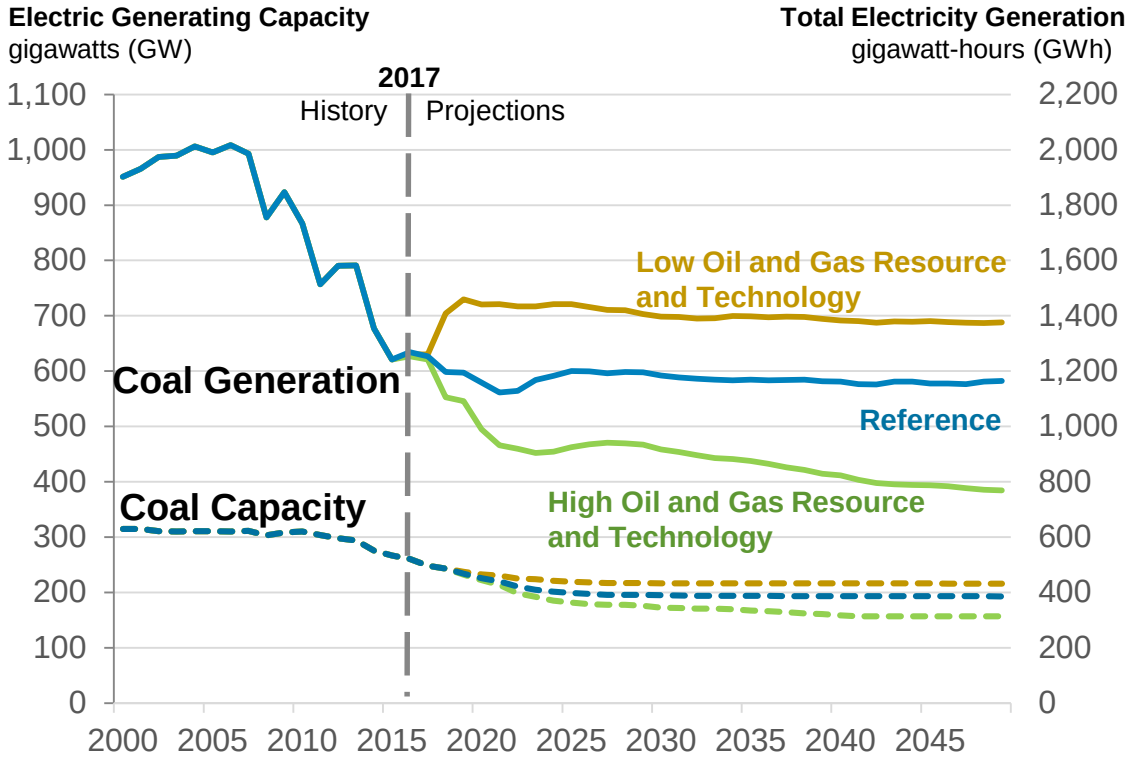
Renewables and natural gas comprise most of the capacity additions throughout the projection period in the Reference case.

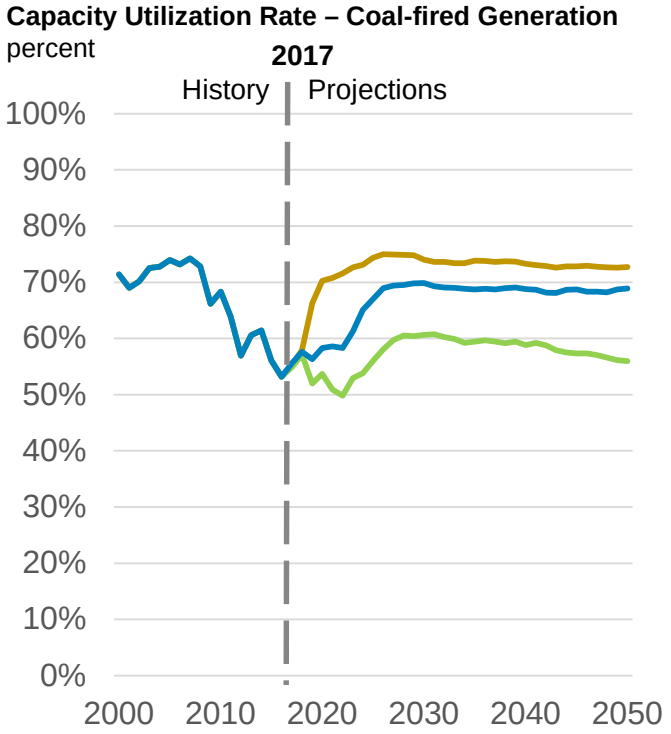
Net summer coal-fired generating capacity in the electric power sector declines disproportionately by region in the AEO2018 Reference case



Source: *AEO2018 Reference case (ref2018.d121317a);*

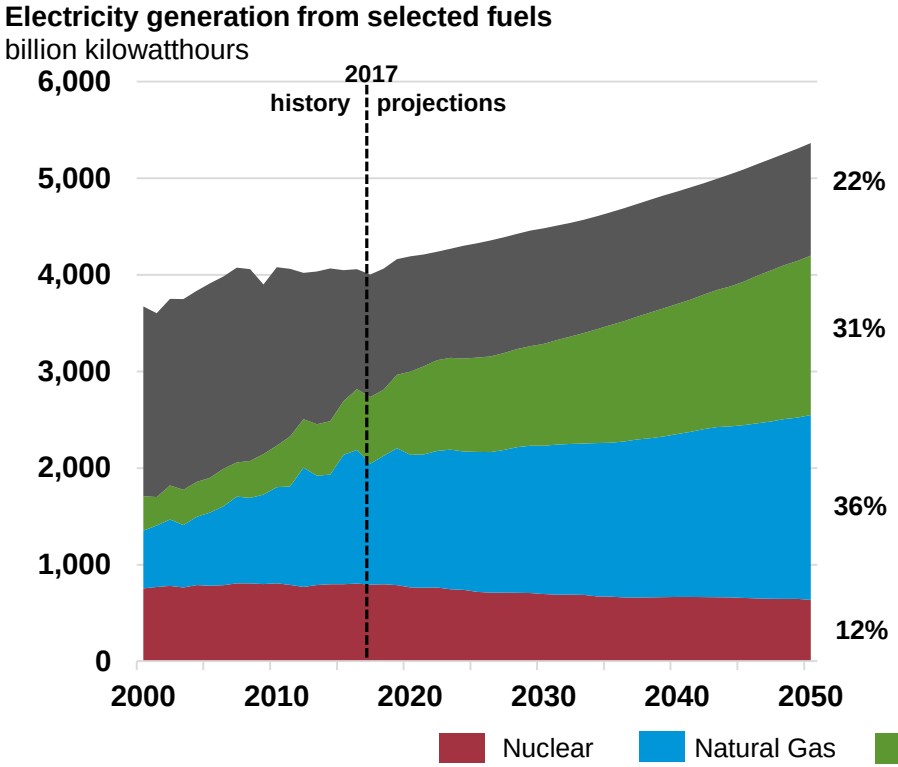
Although coal capacity declines, capacity factors for remaining coal units recover as natural gas prices allow

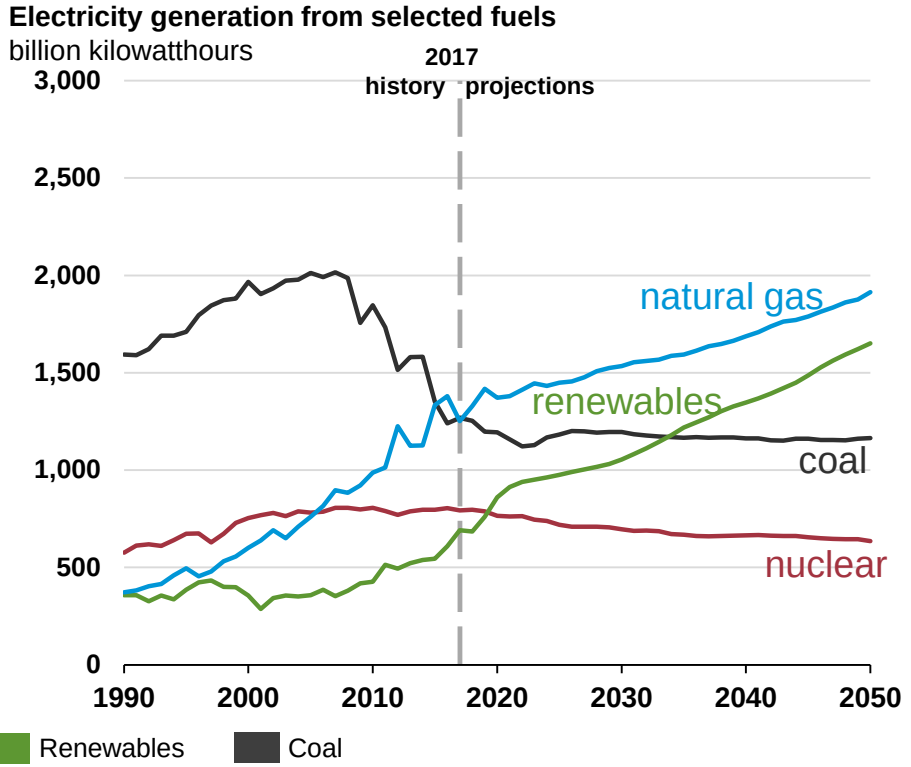




Source: U.S. Energy Information Administration, AEO2018 National Energy Modeling System run REF2018.D1213a, highrt.1213a, and lowrt.1213a.

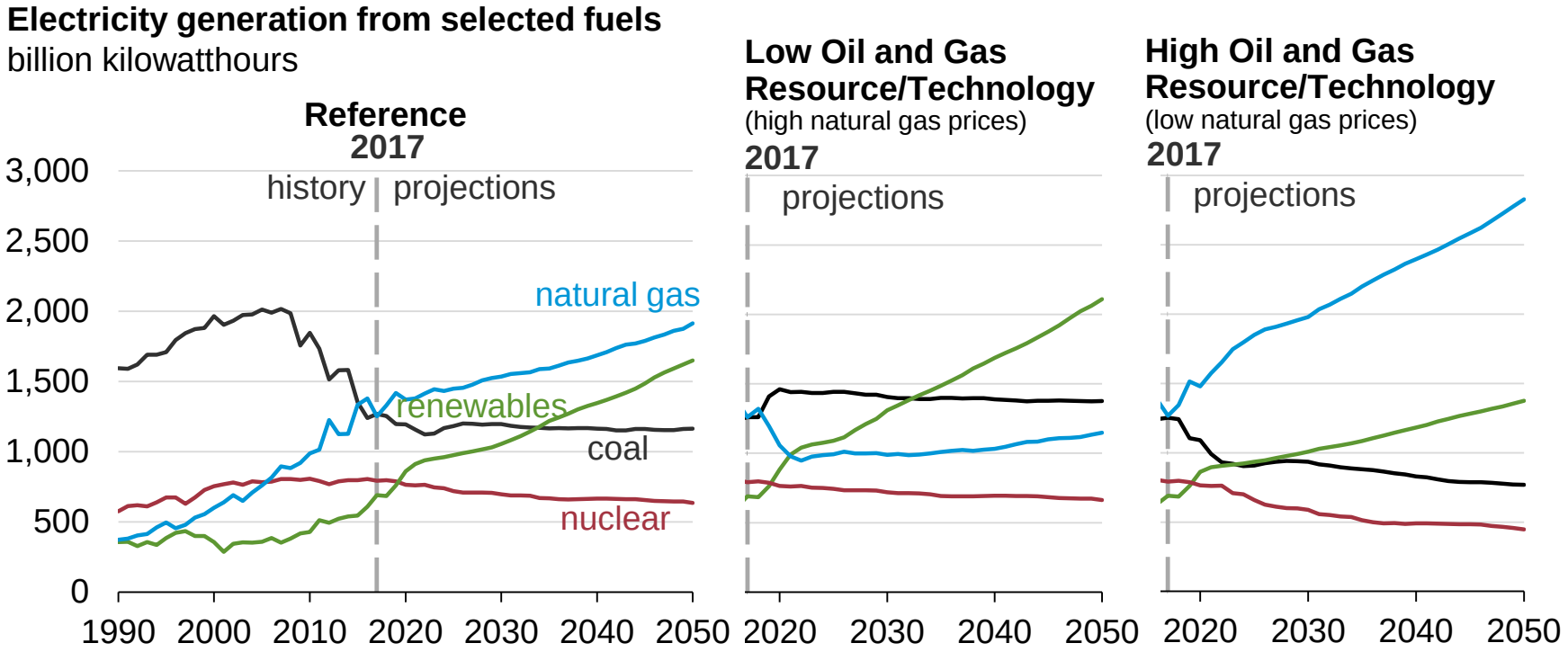
Electricity generation from natural gas and renewables increases steadily with coal and nuclear projected to remain relatively flat in the AEO2018 Reference case





Source: U.S. Energy Information Administration, Annual Energy Outlook 2018.

The projected mix of electricity generation varies widely across cases as differences in fuel prices result in significant substitution

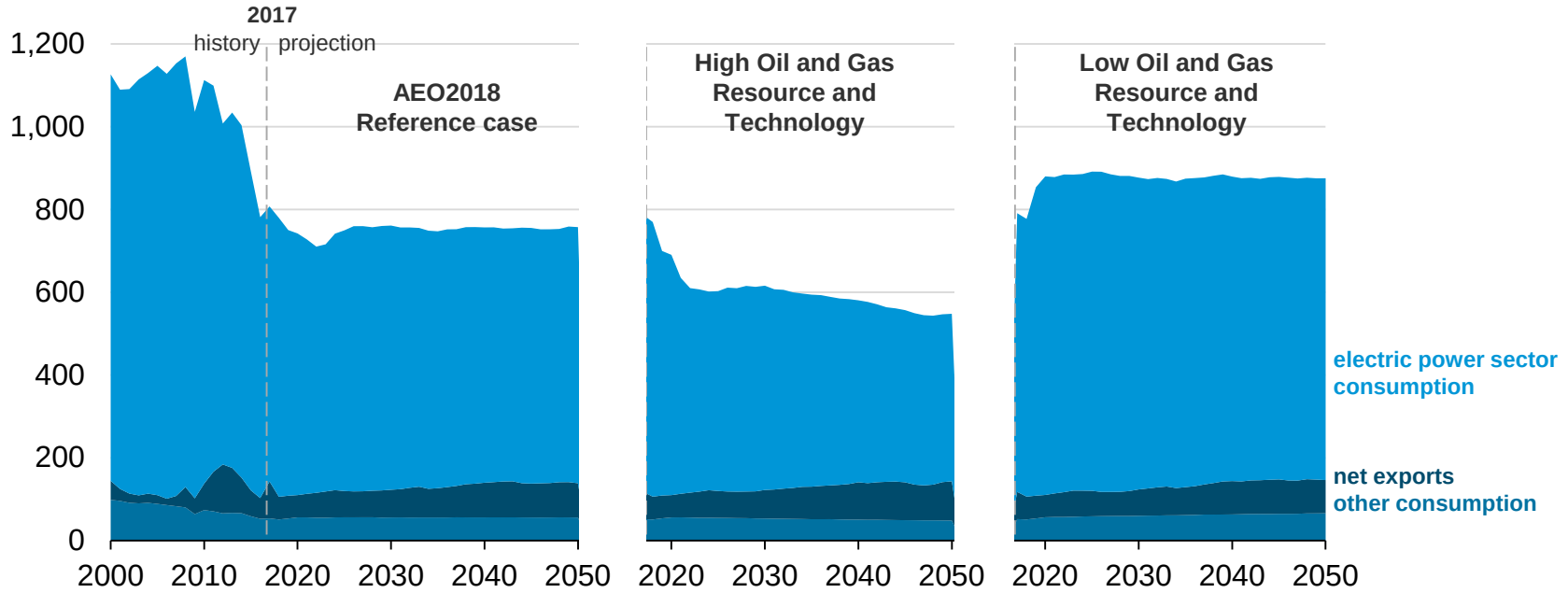


Source: U.S. Energy Information Administration, AEO2018 National Energy Modeling System run REF2018.D1213a, highrt.1213a, and lowrt.1213a.

Electricity sector consumption drives total U.S. coal disposition with stable industrial and slowly-increasing export demand

U.S. coal consumption and net exports

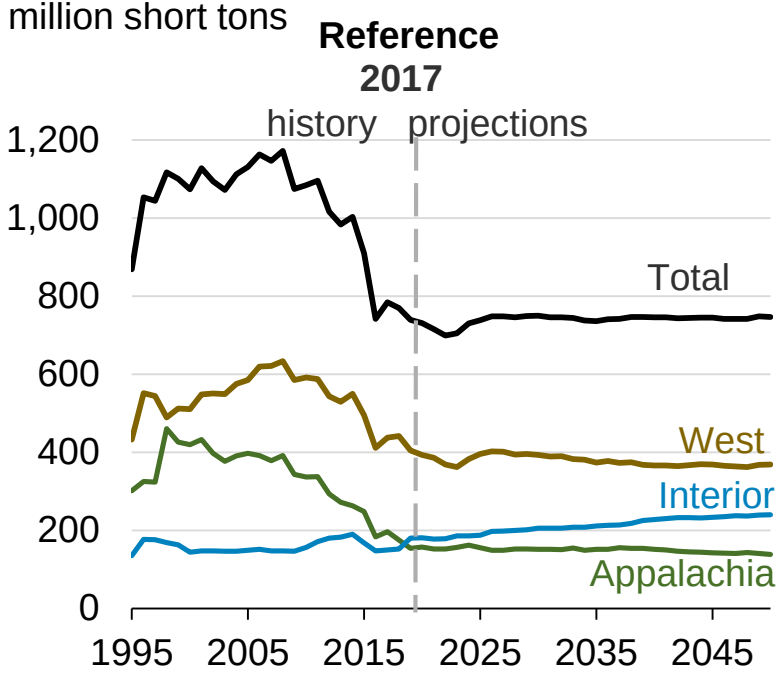
million short tons

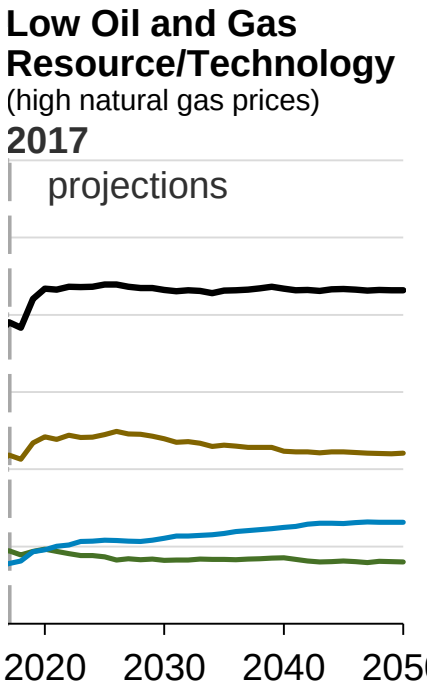


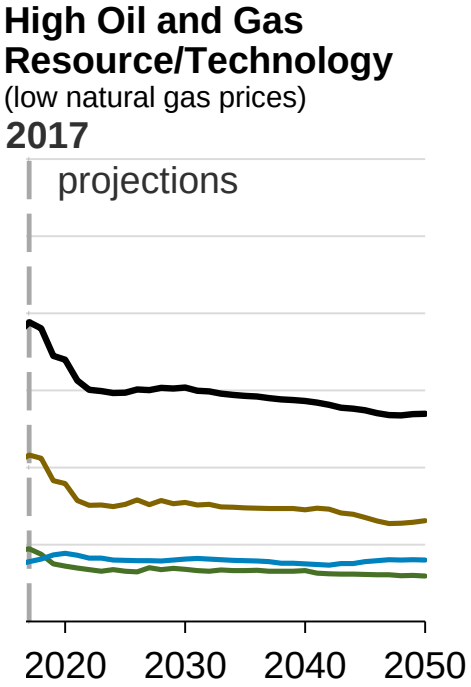
- Source: U.S. Energy Information Administration, AEO2018 National Energy Modeling System run REF2018.D1213a, highrt.1213a, and lowrt.1213a.

Interior region coal production is projected to increase at the expense of the West and Appalachia regions in the Reference case

Coal production by major region
million short tons





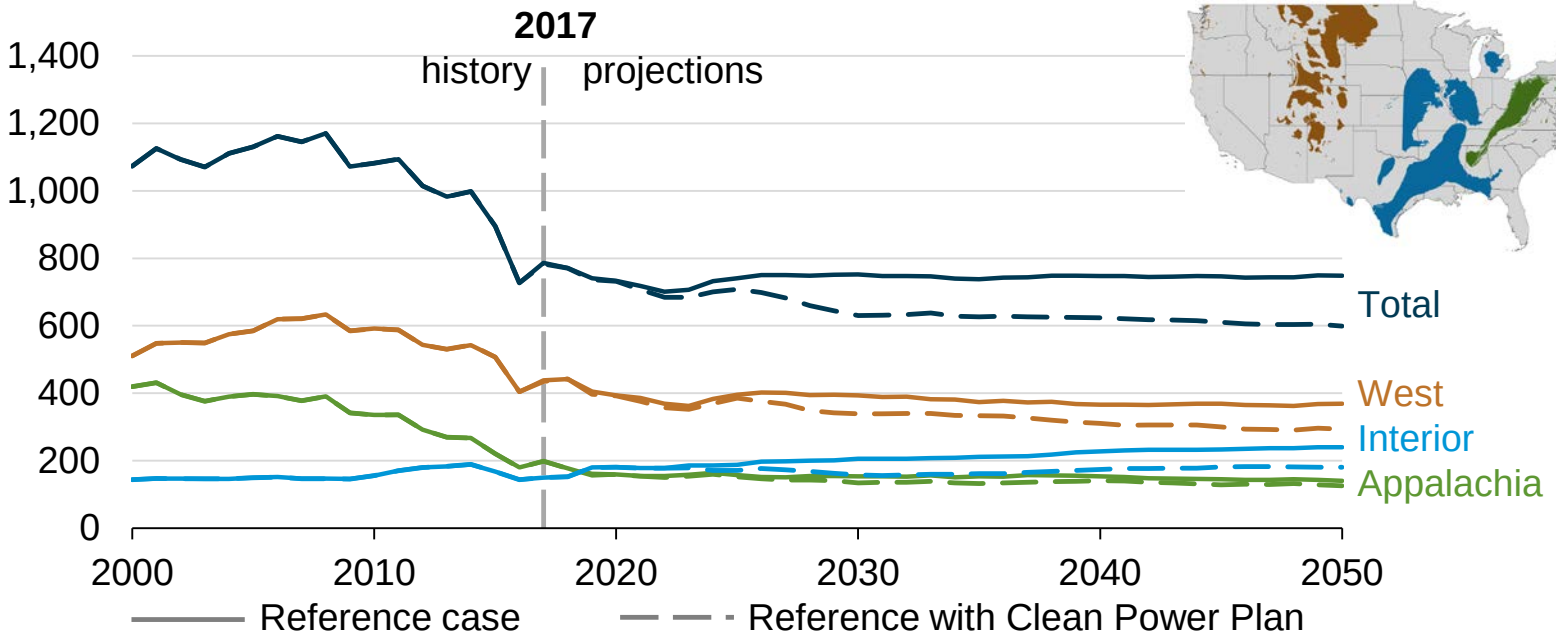


Source: U.S. Energy Information Administration, AEO2018 National Energy Modeling System run REF2018.D1213a, highrt.1213a, and lowrt.1213a.

Coal production remains flat through 2050 in the Reference case and declines slightly if the Clean Power Plan is assumed

U.S. Coal production by region – Reference Case with and without Clean Power Plan

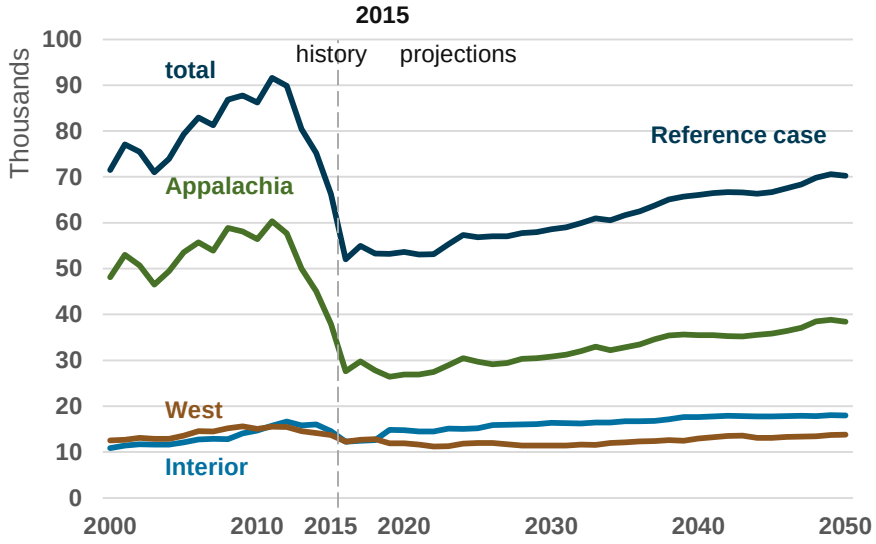
million short tons



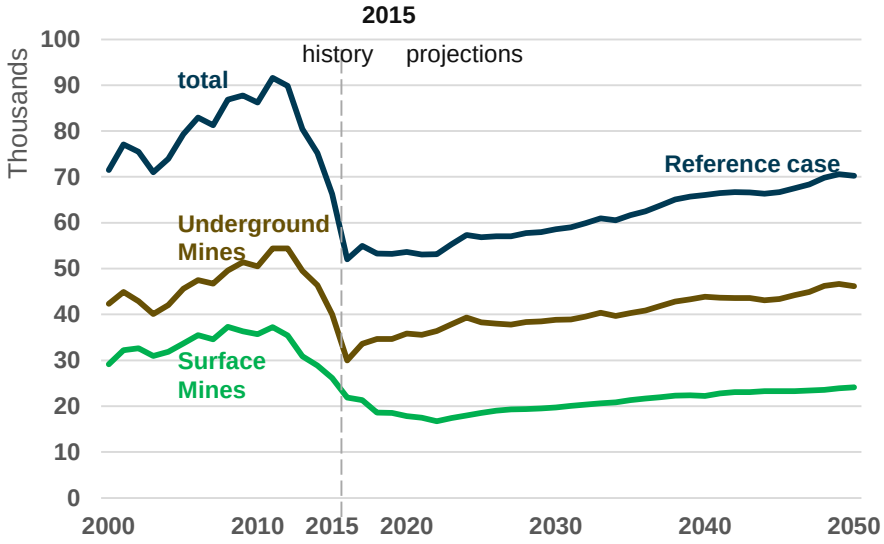
Coal production decreases through 2022 because of retirements of coal-fired electric generating capacity.

Coal mine employment trends reflect impact of declining labor productivity against backdrop of declining production

Coal Mine Employment
Number of Miners



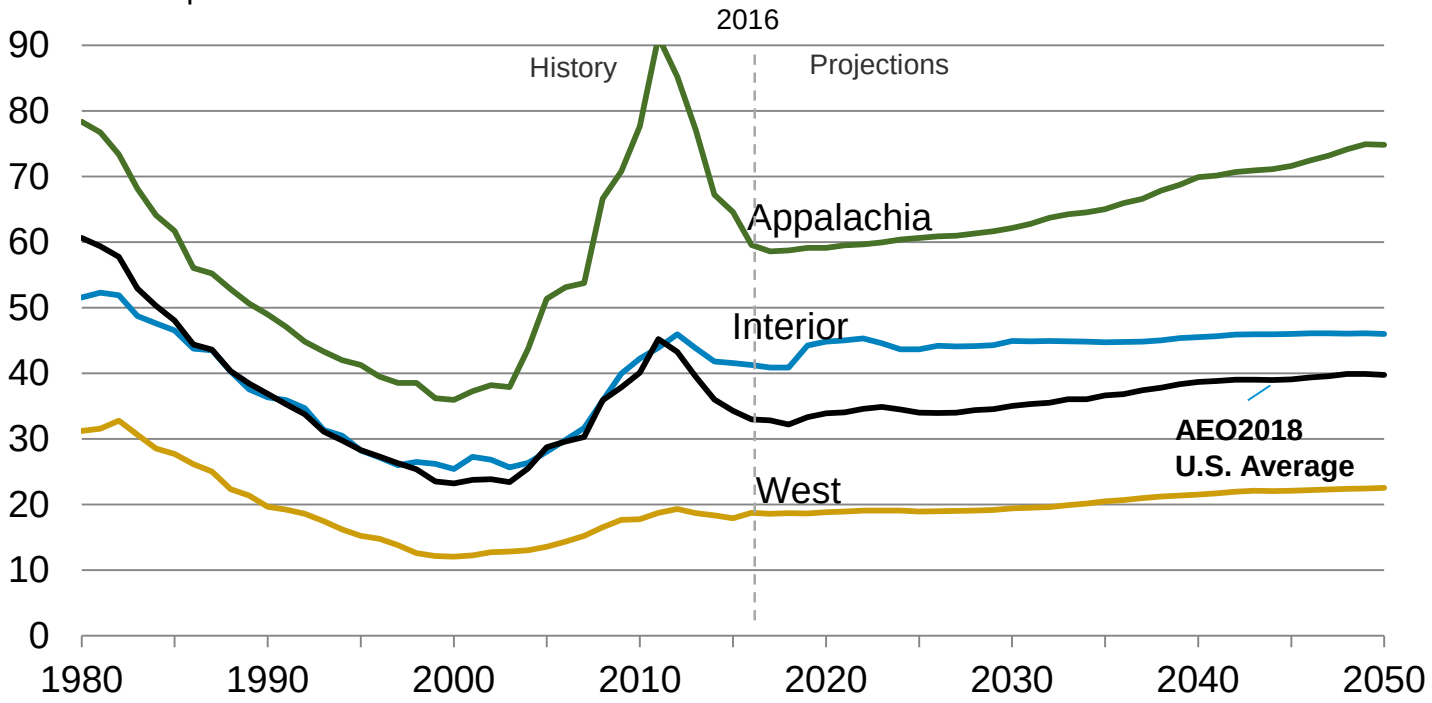
Coal Mine Employment
Number of Miners



Source: AEO2017 Reference case (ref2018.d121317a)

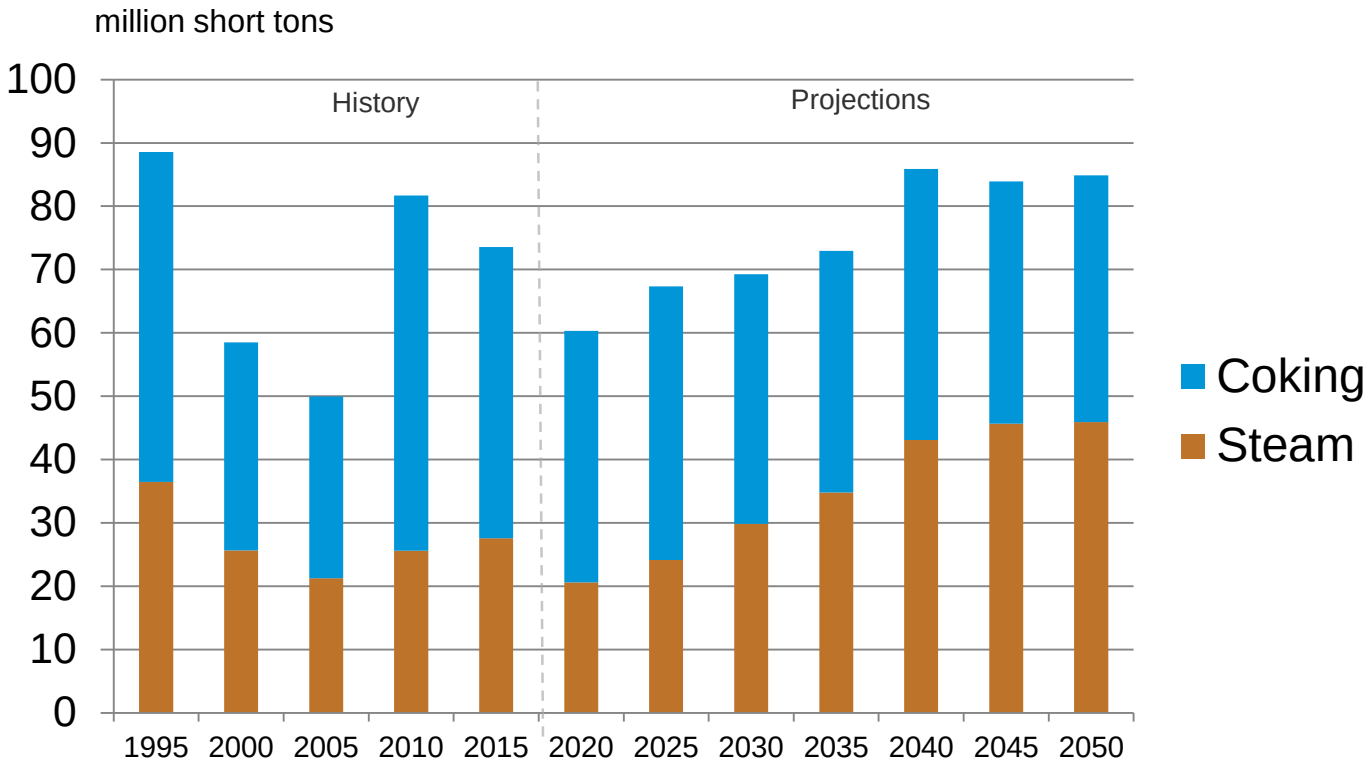
Average minemouth coal prices increase gradually as productivity decreases over time

2017 dollars per short ton



Source: AEO2017 Reference case (ref2018.d121317a)

U.S. coal exports are expected to recover only gradually through 2050



Source: AEO2017 Reference case (ref2018.d121317a)

Coal Market Module (CMM) Updates and Improvements Planned for AEO2019 and beyond

- Implementing 2016/2017 base year updates
- Updating Coal Production Submodule (CPS) econometric parameters
- Allowing for AIMMS code to be opened and closed between cycles to reduce the number of licenses needed when running NEMS
- Enhancing reporting capability by implementing standardized, analytical coal reports directly in the AIMMS software, e.g., supply curve reporting
- International coal supply curves and domestic transportation model improvement efforts planned for AEO2020; International Coal Market Module (ICMM) planned for after IEO2019
- Looking into option of a short-term coal projection working group

Legislative and regulatory changes affecting the AEO2019 from changes in Federal tax code

- Tax Cuts and Jobs Act of 2017
  - Broad, macro feedbacks on electricity demand
  - Changes to investment economics from the change in marginal tax rates and the temporary provisions for immediate expensing
- Section 45Q tax credit for Carbon Capture and Storage
  - Reviewing possible impact on cost treatment in EMM
  - revised (from $20) to $50 per metric ton for secure geologic storage
  - revised (from $10) to $35 per metric ton for EOR, EGR, or utilization
  - NETL is working on an analysis of 45Q; NEMS code they developed may be transferable

Updating methods for projecting changes in generation costs *(Sargent & Lundy study- forthcoming)*

Variables Affecting Annual Changes in Real Spending per kW

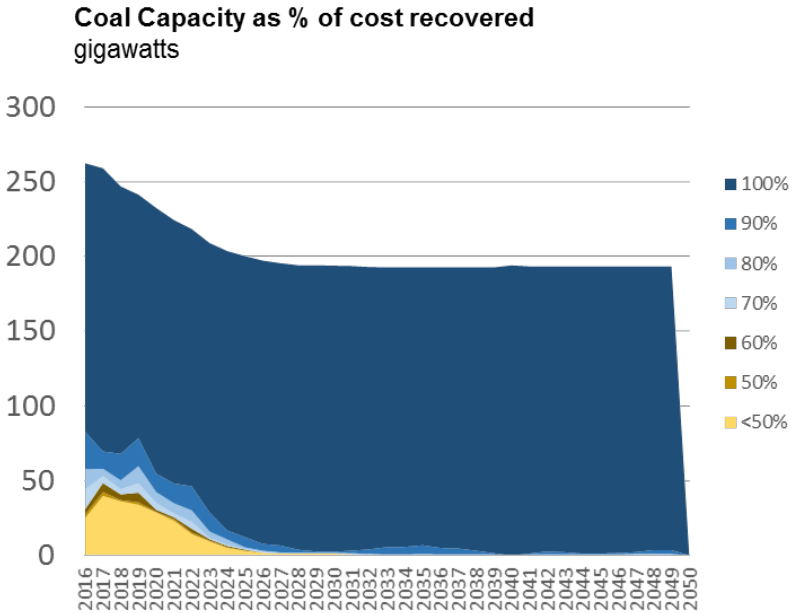
Generating Capacity	Capital Expenditures	O&M Spending
Coal Steam	Age (for units with FGD)	-
Gas/Oil Steam	Capacity	-
Gas/Oil Combined-Cycle	Operating Hours	-
Gas/Oil Combustion Turbines	Starts	-
Conventional Hydropower	-	Age
Pumped Storage – Hydraulic Turbine Reversible	-	-
Solar Thermal – Central Tower	-	-
Solar Photovoltaic – Single-Axis Tracking	-	-
Geothermal	-	-
Wind	Capacity	Age

Key Issues Addressed in Study

- Are there predictable patterns of spending associated with aging/ plant life extension?
- What other variables are critical determinants of spending patterns?
- Is regulatory status a significant factor in spending?
- Is there sufficient historical data on non-hydro renewable generation to determine impacts of aging?

Evaluating alternative measures of generation at-risk: share of cost recovery

AEO2018 Reference Case- Coal Generators



Key issues under consideration

- How does varying current NEMS-EMM treatment (3+ unprofitable periods) influence projected retirements?
- How does use of energy only vs. inclusion of capacity payments influence retirements?
- Is there a generally-accepted industry definition of generation-at-risk?

Alternative generation at-risk criteria

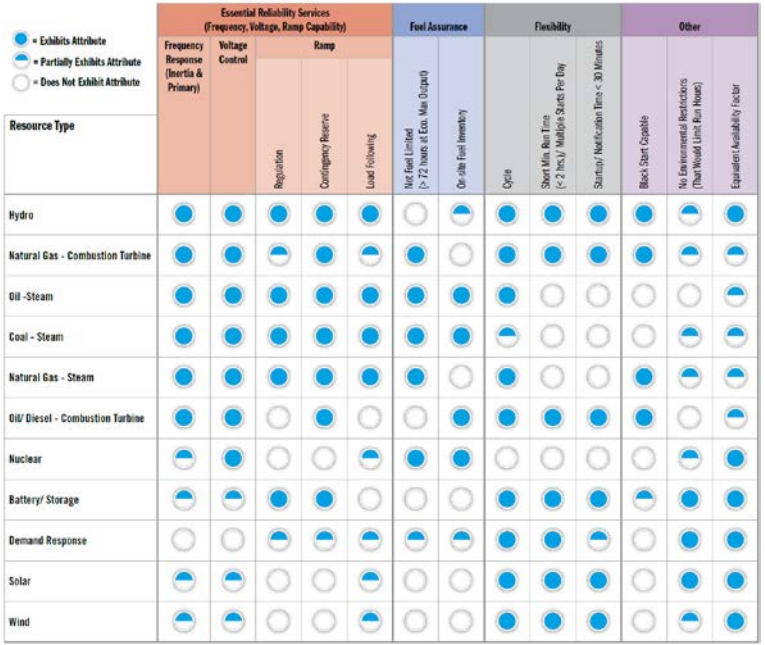
- **PJM Coal** *(2011)*
  - Physical Screen[1]: Older than 40 years old; less than 400 MW are “most at risk”
  - Economic Screen: “At risk” level measured by costs relative to replacement capacity costs Net Cost of New Entry (Net CONE
- **PJM Nuclear and Coal** *(2017)*
  - More stringent criteria[2]: units that have not recovered 100% avoidable costs from total market (energy, ancillary and capacity market) revenues
  - Relaxed criteria
    - Coal: units that have recovered <90% of total market revenues
    - Nuclear: units that have not recovered 100% of avoidable costs based on forward price

[1]Coal Capacity at Risk for Retirement in PJM: Potential Impacts of the Finalized EPA Cross State Air Pollution Rule and Proposed National Emissions Standards for Hazardous Air Pollutants

[2]2017 State of the Market Report for PJM: Volume 2: Detailed Analysis

Evaluating alternative means of representing impact of generation diversity

PJM rating of generation types by reliability attributes



● = Exhibits Attribute
◒ = Partially Exhibits Attribute
○ = Does Not Exhibit Attribute

Resource Type	Essential Reliability Services (Frequency, Voltage, Ramp Capability)					Fuel Assurance		Flexibility			Other		
	Frequency Response (Inertia & Primary)	Voltage Control	Ramp			Not Fuel Limited (> 72 hours at Eco. Max Output)	On-site Fuel Inventory	Cycle	Short Min. Run Time (< 2 hrs.) / Multiple Starts Per Day	Start-up / Notification Time < 30 Minutes	Black Start Capable	No Environmental Restrictions (That Would Limit Run Hours)	Equivalent Availability Factor
			Regulation	Contingency Reserve	Load Following								
Hydro	●	●	●	●	●	○	◒	●	●	●	●	◒	●
Natural Gas - Combustion Turbine	●	●	◒	●	◒	●	○	●	●	●	●	◒	◒
Oil -Steam	●	●	●	●	●	●	●	●	○	○	○	○	◒
Coal - Steam	●	●	●	●	●	●	●	◒	○	○	○	◒	◒
Natural Gas - Steam	●	●	●	●	●	●	○	●	○	○	●	◒	◒
Oil/ Diesel - Combustion Turbine	●	●	○	●	○	○	●	●	●	●	●	○	◒
Nuclear	◒	●	○	○	◒	●	●	○	○	○	○	◒	●
Battery/ Storage	◒	◒	●	●	○	○	○	●	●	●	◒	●	●
Demand Response	○	○	◒	◒	◒	◒	◒	●	●	◒	○	●	●
Solar	◒	◒	○	○	◒	○	○	●	●	●	○	●	●
Wind	◒	◒	○	○	◒	○	○	●	●	●	○	◒	●

Source:
http://www.pjm.com/~/media/library/reports-notices/special-reports/20170330-pjms-evolving-resource-mix-and-system-reliability.ashx pg. 16

Key issues under consideration

- What other attributes ought to be considered? Which could be eliminated, or represented differently?
- How do these reliability attributes contribute to grid resilience?
- Should these attributes be weighted equally, or are some more critical than others?
- What is the best way to represent these factors in the model?

EIA evaluates technology costs for select emerging and existing technologies on a periodic basis

Technology	First available year[1]	Size (MW)	Lead time (years)	Base overnight cost (2017 $/kW)	Project Contingency Factor[2]	Technological Optimism Factor[3]	Total overnight cost[4,10] (2017 $/kW)	Variable O&M[5] (2017 $/MWh)	Fixed O&M (2017$/kW/yr)	Heat rate[6] (Btu/kWh)	nth-of-a-kind heat rate (Btu/kWh)
Coal with 30% carbon sequestration (CCS)	2021	650	4	4,641	1.07	1.03	5,089	7.17	70.70	9,750	9,221
Coal with 90% CCS	2021	650	4	5,132	1.07	1.03	5,628	9.70	82.10	11,650	9,257
Conv Gas/Oil Combined Cycle (CC)	2020	702	3	935	1.05	1.00	982	3.54	11.11	6,600	6,350
Adv Gas/Oil CC	2020	429	3	1,026	1.08	1.00	1,108	2.02	10.10	6,300	6,200
Adv CC with CCS	2020	340	3	1,936	1.08	1.04	2,175	7.20	33.75	7,525	7,493
Conv Combustion Turbine[7]	2019	100	2	1,054	1.05	1.00	1,107	3.54	17.67	9,880	9,600
Adv Combustion Turbine	2019	237	2	648	1.05	1.00	680	10.81	6.87	9,800	8,550
Fuel Cells	2020	10	3	6,192	1.05	1.10	7,132	45.64	0.00	9,500	6,960
Adv Nuclear	2022	2,234	6	5,148	1.10	1.05	5,946	2.32	101.28	10,460	10,460
Distributed Generation - Base	2020	2	3	1,479	1.05	1.00	1,553	8.23	18.52	8,969	8,900
Distributed Generation - Peak	2019	1	2	1,777	1.05	1.00	1,866	8.23	18.52	9,961	9,880
Battery Storage	2018	30	1	2,067	1.05	1.00	2,170	7.12	35.60	N/A	N/A
Biomass	2021	50	4	3,584	1.07	1.00	3,837	5.58	112.15	13,500	13,500
Geothermal[8,9]	2021	50	4	2,615	1.05	1.00	2,746	0.00	119.87	9,271	9,271
MSW - Landfill Gas	2020	50	3	8,170	1.07	1.00	8,742	9.29	417.02	18,000	18,000
Conventional Hydropower[9]	2021	500	4	2,634	1.10	1.00	2,898	1.33	40.05	9,271	9,271
Wind[10]	2020	100	3	1,548	1.07	1.00	1,657	0.00	47.47	9,271	9,271
Wind Offshore[8]	2021	400	4	4,694	1.10	1.25	6,454	0.00	78.56	9,271	9,271
Solar Thermal[8]	2020	100	3	3,952	1.07	1.00	4,228	0.00	71.41	9,271	9,271
Solar PV - tracking[8, 11]	2019	150	2	2,004	1.05	1.00	2,105	0.00	22.02	9,271	9,271
Solar PV – fixed tilt[8,11]	2019	150	2	1,763	1.05	1.00	1,851	0.00	22.02	9,271	9,271

Source: U.S. Energy Information Administration, Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2018, Table 8.2., p. 2.

Q&A on AEO2018 Projections

- Recent article by IEEFA highlights standard questions regarding EIA's modeling of coal markets…
  - Can coal plants recover capacity utilization up to 70% on average if gas prices are favorable?
  - Should EIA consider some form of 'planned obsolescence' for coal in response to electric utility and corporate purchasing pressures, i.e., shift away from modeling retirement decisions as economic decisions?
- Any issues with coal mining labor productivity trends? Can Eastern Interior keep improving?
- Will the U.S. remain a swing coal exporter?
- Any insights on how to value resilience and generation diversity?
- Should additional technologies be evaluated by EIA?

MARCH 30, 2018

EIA projects that U.S. coal demand will remain flat for several decades

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You are here: Home » Subject » Commentary » IEEFA Update: The U.S. Energy Information Administration Continues to Miss the Mark

Dennis Wamsted and Seth Feaster | May 4, 2018

IEEFA Update: The U.S. Energy Information Administration Continues to Miss the Mark

In Its Coal-Industry Analyses, a Federal Agency Seems Oblivious to Reality

The Energy Information Administration, the federal agency responsible for national energy data compilation and analysis, has been historically out of sync on its U.S. coal-industry projections and seems every bit as off the mark as ever these days.

It's as if the EIA can't quit going rogue from reality.

In a "Today in Energy" article published on the EIA website on March 30, the agency—which is funded by taxpayer dollars—discusses its logic-defying forecast, part of its "Annual Energy Outlook 2018," on how it envisions coal's future role in the U.S. electricity-generation equation.

For more information

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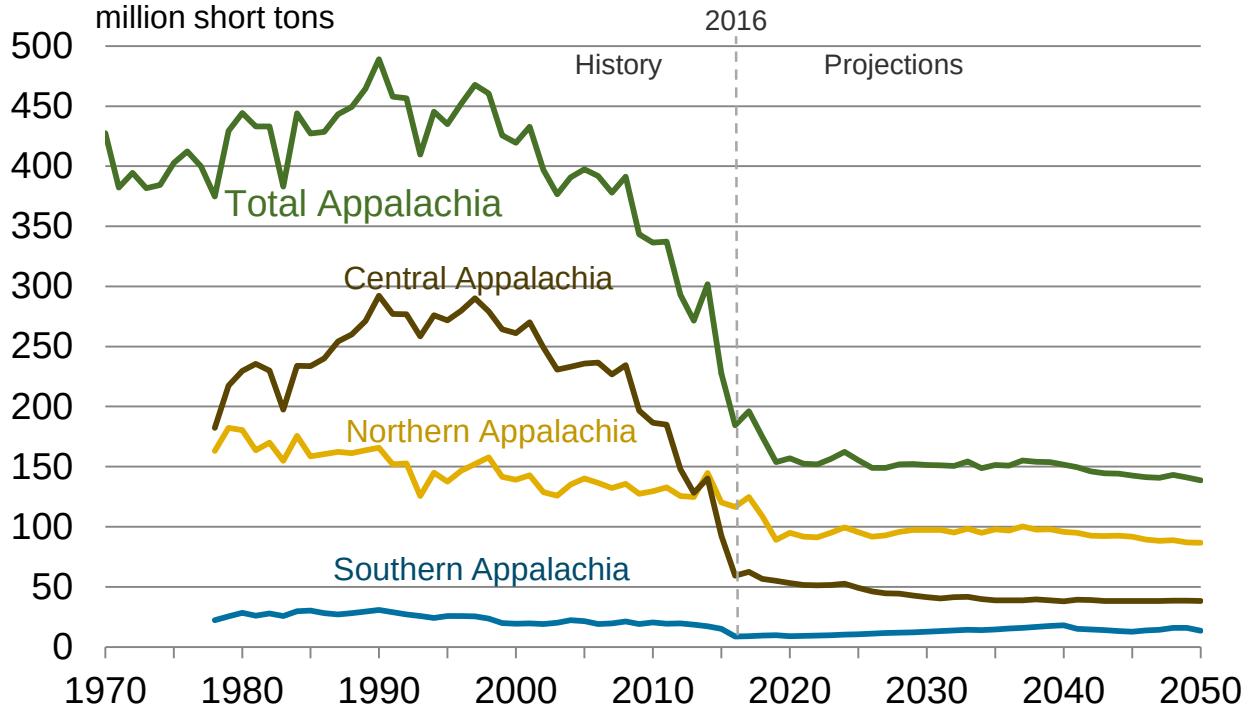
Bonnie West, IEO Coal Models and Projections | Bonnie.West@eia.gov | (202) 586-2415 (returning in August)

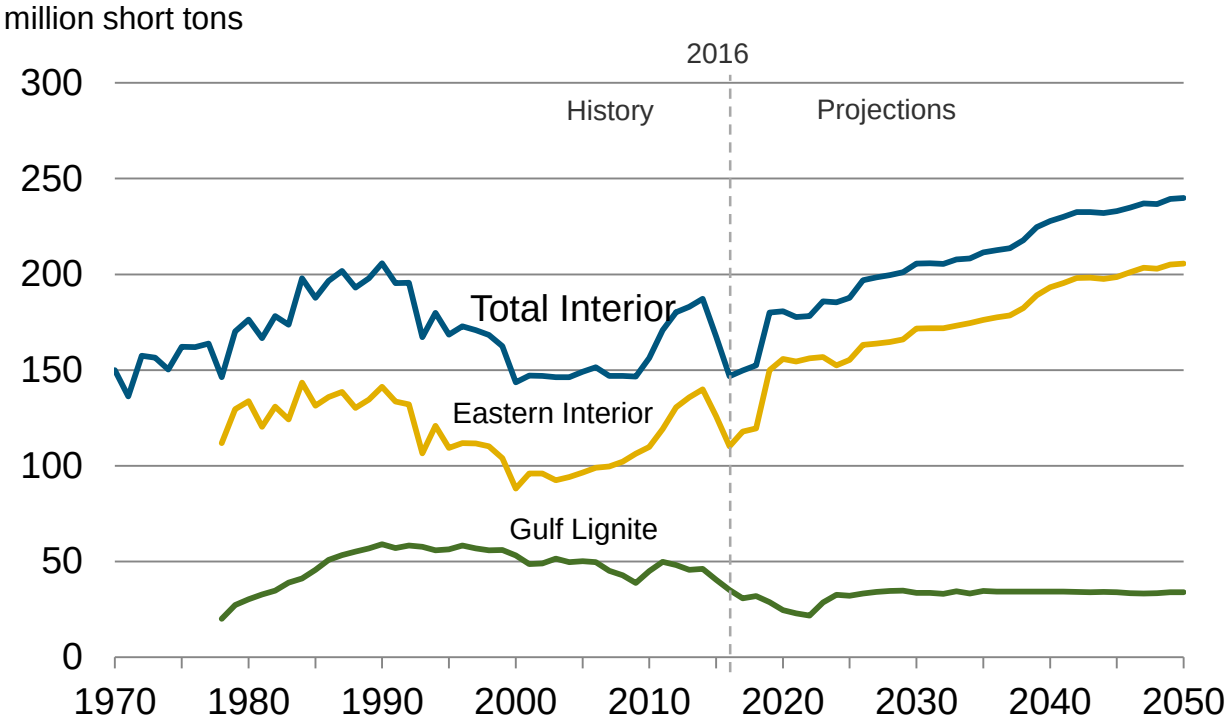
U.S. Energy Information Administration home page | www.eia.gov
Annual Energy Outlook | www.eia.gov/aeo
Short-Term Energy Outlook | www.eia.gov/steo
International Energy Outlook | www.eia.gov/ieo
Monthly Energy Review | www.eia.gov/mer
Today in Energy | www.eia.gov/todayinenergy
State Energy Profiles | www.eia.gov/state
Drilling Productivity Report | www.eia.gov/petroleum/drilling/
International Energy Portal | www.eia.gov/beta/international/?src=home-b1

Appalachian coal production declines gradually as productivity declines, but is buffered by relatively steady met coal demand



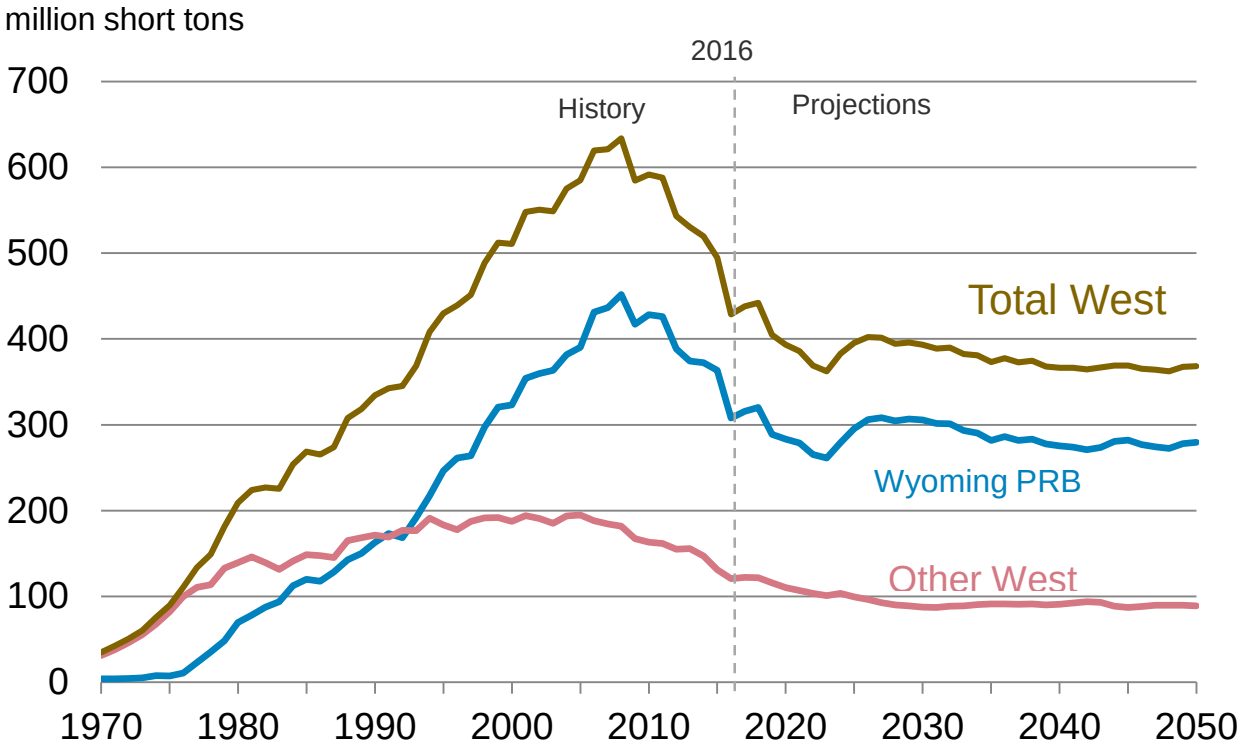
- Source: AEO2017 Reference case (ref2017.d120816a),
- Except for Appalachian total, data for 1978-1985 exclude production from small (<10,000 short tons) coal mines

Interior coal production remains declines only slightly from 2016 levels under the CPP due to increasing productivity and competitiveness with low-sulfur coals



Source: AEO2017 Reference case (ref2017.d120816a)

Western coal production sees the greatest rate of decline under the CPP



Source: AEO2017 Reference case (ref2017.d120816a)