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AEO2020 First Coal Working Group Meeting

Coal and Uranium Analysis Team

April 9, 2019 | Washington, D.C.

Agenda

- Introductions and overview of AEO2020 process
- Review of AEO2019 assumptions and projections
  - Legislative and regulatory review
  - Three key assumptions and three key industry trends
  - Summary of results for coal capacity, generation, disposition, regions, labor, and exports
- Model updates and improvements for AEO2020 and beyond
  - Summary of modeling improvements for AEO2020 affecting the coal market
  - Seaborne coal freight rate methodology improvements for AEO2020
  - Coal transportation rate increase methodology options for AEO2020/1
  - International coal supply curve estimation options for AEO2021
- Q&A opportunity at the end of each subsection

Overview of Annual Energy Outlook 2020 (AEO2020)

- AEO2020 will be a full release
  - Flip-book published
  - Core side cases will be run
    - Reference
    - High/Low Oil and Gas Resource Technology
    - High/Low Oil Price
    - High/Low Economic Growth
  - Issues in Focus articles or related side cases will be published along with related side case results
- Assumptions and model documentation will be updated
- Second working group session will take place in late summer
- Publication is scheduled for January 2020 (estimated)

What is the Reference case?

- The Reference case projection assumes trend improvement in known technologies along with a view of economic and demographic trends reflecting the current views of leading economic forecasters and demographers.

- The Reference case generally assumes that current laws and regulations affecting the energy sector, including sunset dates for laws that have them, are unchanged throughout the projection period.

- The potential impacts of proposed legislation, regulations, and standards are not included.

- EIA addresses the uncertainty inherent in energy projections by developing side sensitivity cases with different assumptions of macroeconomic growth, world oil prices, technological progress, and energy policies.

- Projections in the AEO should be interpreted with a clear understanding of the assumptions that inform them and the limitations inherent in any modeling effort.

AEO2019 sensitivity cases examine impacts of alternative market assumptions

Selected Sensitivity Cases	Description
Reference	Assumes trend improvement in known technologies and expects current economic and demographic trends to continue
High Oil and Natural Gas Resource and Technology (HRT)	Applies lower oil and natural gas extraction costs and higher resource availability than in the Reference case, which allows for higher levels of oil and natural gas production at lower delivered prices
Low Oil and Natural Gas Resource and Technology (LRT)	Applies higher oil and natural gas extraction costs and lower resource availability than in the Reference case, which results in lower levels of oil and natural gas production at higher delivered prices

Legislation and regulations: AEO2019 assumptions and outlook for AEO2020

Affordable Clean Energy (ACE) proposed rule

- EPA proposed the Affordable Clean Energy (ACE) rule in August 2018 to replace the Clean Power Plan (CPP), which:
  - Revises EPA's BSER ("best system of emission reduction") finding for GHG emissions from existing power plants to include only heat-rate efficiency improvements
  - Gives states a list of "candidate technologies" that can be used to establish performance standards for use in state plans, rather than setting specific technology-based standards,
  - EIA is addressing ACE in the Electricity Markets Module (EMM) by offering existing coal units the choice to either upgrade to an HRI option identified in EIA's CPP study or retire by 2025; this approach relies on the 2015 EIA study of heat rate improvement (HRI) potential and costs for existing coal units
- EPA's (ACE) Rule was not final and not included in AEO2019 Reference case
  - Final rule expected in spring of 2019
  - Will be included in AEO2020 if the rule is finalized *timely* in 2019

EPA's New Source Performance Standards (NSPS)

- All AEO2019 cases include EPA's New Source Performance Standards (NSPS) limiting CO2 emissions from new plants
  - The EPA released proposed revisions that would eliminate the Carbon Capture and Sequestration (CCS) requirement and specify CO2 emission rates of 2,000 lb CO2/MWh-gross for large units (super-critical), 1,900 lb for small units (sub-critical), and 2,200 lb for new coal refuse-fired units; and it would change applicability of rules to modified units

NSPS CO2 emission standard	**Proposed**	**Seeking comment on alternative range**
	lbs/CO2/mmBtu (gross energy output)	
Large units (super-critical)	2,000	1,700 - 1,900
Small units (sub-critical)	1,900	1,800 - 2,000
New coal refuse-fired units	2,200	2,000 - 2,200

Source: U.S. EPA, EPA Proposal: NSPS for GHG Emissions from New, Modified, and Reconstructed EGUs; p. 146.

  - AEO2020 assumptions would be modified to reflect the *timely* issuance of a final rule in 2019

- All cases in the AEO2019 apply a 3% adder to the cost of capital for new coal
  - Includes units or upgrades to existing units without maximum sequestration options (90% removal) to account for risk of future tightening of CO2 emissions standards and other policies affecting coal use
  - Will also be applied in AEO2020

Mercury and Air Toxics Standards (MATS) and Cross State Air Pollution Rule (CSAPR)

- The Mercury and Air Toxics Standards (MATS) are included in all AEO2019 cases
  - "EPA issued a proposed revised Supplemental Cost Finding for the Mercury and Air Toxics Standards, as well as the Clean Air Act required 'risk and technology review.'…and proposes to determine that it is not 'appropriate and necessary' to regulate HAP emissions from power plants under Section 112 of the Clean Air Act. The emission standards and other requirements of the MATS rule, first promulgated in 2012, ***would remain in place***, however, since EPA is not proposing to remove coal- and oil-fired power plants from the list of sources that are regulated under Section 112 of the Act." (quoted from EPA website; emphasis added).
  - MATS will be included in all AEO2020 cases, accordingly, unless further guidance is issued to the contrary
- EPA's Cross-State Air Pollution Rule (CSAPR) is included in all AEO2019 cases and will be maintained in all AEO2020 cases

Other EPA regulations affecting coal generating units and effluent limitation guidelines

- 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 on July 31, 2021 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

- EPA is promulgating Revised Effluent Limitation Guidelines
  - Deadlines for compliance postponed until November 1, 2020 while EPA promulgates a revised rule starting in August, 2017; draft rule anticipated by December, 2020
  - Rulemaking is considering possible revisions to the Best Available Technology (BAT) effluent limitations and pretreatment standards for existing sources

EPA's Coal Combustion Residual Regulations

- The EPA is reviewing 2015 Coal Combustion Residual regulations
  - The EPA gave states flexibility to apply alternative standards to achieve compliance, and states are allowed until 2020 to begin closing or retrofitting unlined ponds violating groundwater standards
  - EPA is addressing an August 2018 decision that required EPA to strengthen the 2015 rule
  - Individual states, such as Virginia and North Carolina, are enacting legislation or ordering utilities to address coal ash in unlined pits, and EPA recently raised concerns regarding certain provisions in Missouri's plan
  - Environmental and other groups are stepping up legal actions as states act under their expanded authority from EPA and under the 2015 rule
  - Modeling is difficult because the potential cost implications vary considerably by individual electric generating unit, and are incorporated into the AEO on as-revealed basis via reporting on survey Form EIA-860

EPA's Waters of the U.S. (WOTUS) definition and coal excise taxes

- EPA proposed a revised definition of Waters of the U.S. (WOTUS) in December, 2018 that would generally scale back waterways covered under the Clean Water Act
  - EPA and Army Corps of Engineers recently stopped opposing the delay in enforcing the previous definition finalized in 2015
  - Assessing the impact for the coal industry is problematic because most economic analysis to date appears to be based on case studies or other, anecdotal or high-level assessment at this time
- Coal excise tax rates for the Black Lung Disability Trust Fund declined on 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 actions affecting coal producers

- U.S. District Court of Montana ruled in February 2019 that the Office of Surface Mining and Reclamation (OSMRE) should have better accounted for the impacts of coal transportation, the non-climate-combustion effects, and the social cost of carbon when it issued an Environmental Assessment (EA) for the Spring Creek mine expansion
  - The ruling allows OSMRE to correct the National Environmental Protection Act (NEPA) violations and update the EA and to determine if a full Environmental Impact Statement (EIS) is required to seek the Court's approval
  - The potential implications for federal coal leasing will depend on the final adjudication
- U.S. Department 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
- Office of Surface Mining's Stream Protection Rule was nullified in 2017 and formal programmatic consultation reinitiated

State actions to control greenhouse gas emissions (1 of 2)

- Several states are actively considering or have already passed strict carbon emission policies
  - For example, New Mexico enacted legislation in March,2019 calling for investor-owned utilities and rural electric cooperatives to procure at least half their electricity from renewable sources by 2030 and 80% by 2040, with a 100% carbon-free requirement taking effect in 2045 for utilities and 2050 for electric co-ops
  - Hawaii and the District of Columbia have passed similar measures
  - Other states are considering similar options with targets of 50% to 100% carbon-free electricity generation that may be included in the AEO2020 if the states take action in time for the AEO2020 development cycle, including: AZ, FL, IL, MD, ME, MN, NC, NV, WA, WI
- Existing California regulations are included in AEO2019
  - 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
  - SB-1368 prohibits California utilities from entering into long-term financial commitments for base load generation, unless in compliance with CO_2 emissions performance standard of 1,100 lbs/MWh
  - SB-100 clean energy standard calls for a 60% renewable generation requirement by 2030, as required under previous legislation, and for carbon-free electric generation by 2045

State actions to control greenhouse gas emissions (2 of 2)

- The Northeast's Regional Greenhouse Gas Initiative (RGGI) program included in AEO2019
  - New Jersey and Virginia recently opted in and may be included in AEO2020
- State-level Renewable Portfolio Standards (RPS) and Zero Emission Credit (ZEC) programs updated each AEO cycle

Issues affecting western U.S. coal producers

- Oregon passed S.B. 1547 in 2016 that requires utilities to exit out-of-state coal contracts by 2030
  - Potential implications for coal holdings by PacifiCorp, including Jim Bridger (WY; 2/3 owner), Hunter, Huntington, Dave Johnston, Naughton, Wyodak, Craig (partial owner), Colstrip (partial owner), and Hayden (partial owner)
  - Wyoming passed Senate File 159 requiring utilities to make a good faith attempt to sell coal plants purchased under an agreement approved by the state's commission, and ratepayers in Wyoming would assume the costs of buying the coal plant in operation
- U.S. Pacific-Northwest coal terminal development stalled/challenged at this time
  - Lawsuit is ongoing by the proposed, 44-MMtpy Millennium terminal's stakeholders to challenge Washington state's 2017 denial of the Clean Water Act Section 401 certification
  - Army Corps revived its environmental review of the project in October 2018, although it cannot issue a permit for the project unless the Washington state's certification denial is reversed or set aside

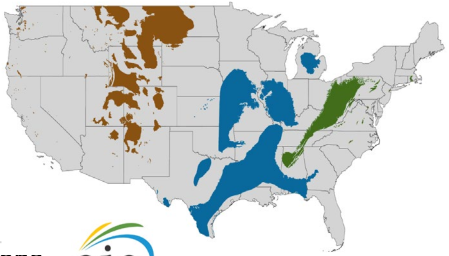
Section 45Q tax credit for Carbon Capture and Storage

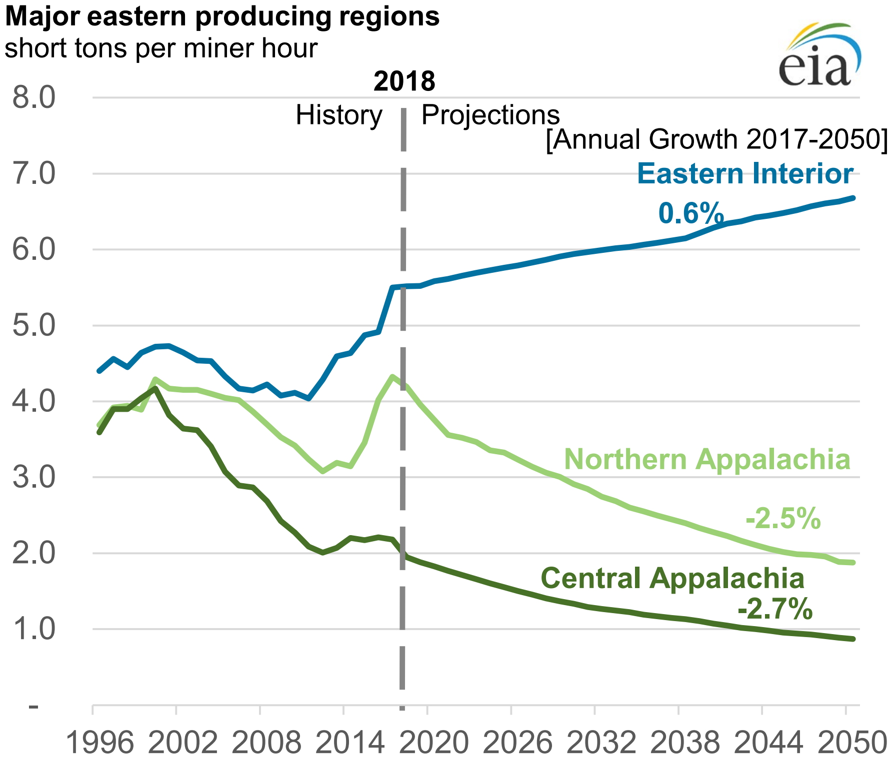
- Section 45Q tax credit for Carbon Capture and Storage is not reflected in AEO2019
  - Revised from $20 to $50 per metric ton for secure geologic storage, and from $10 to $35 per metric ton for Enhanced Oil or Gas Recovery (EOR/EGR) or utilization
  - Changes in tax code are planned for incorporation into AEO2020, with possible indirect implications for coal disposition

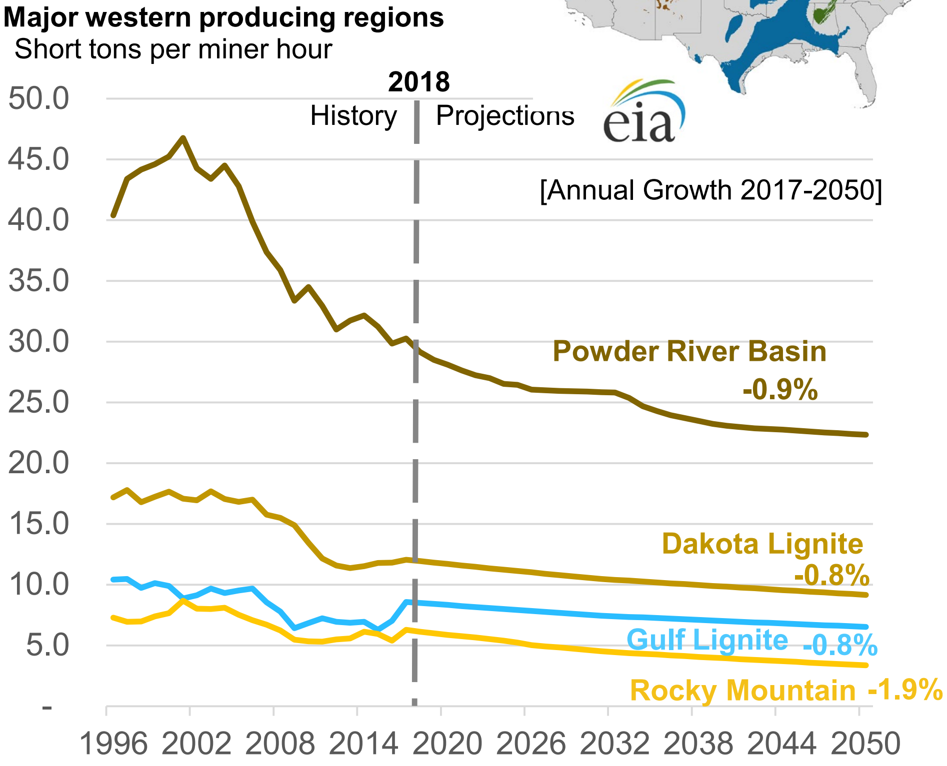
- Note: The modeling of CCS and 45Q occurs in the Electricity Market Module (EMM), Capture, Transport, Utilization and Storage Module (CTUS), and the Oil and Gas Supply Module (OGSM)

AEO2019 assumptions and trends

Coal productivities projected to continue declining, except in the Eastern Interior

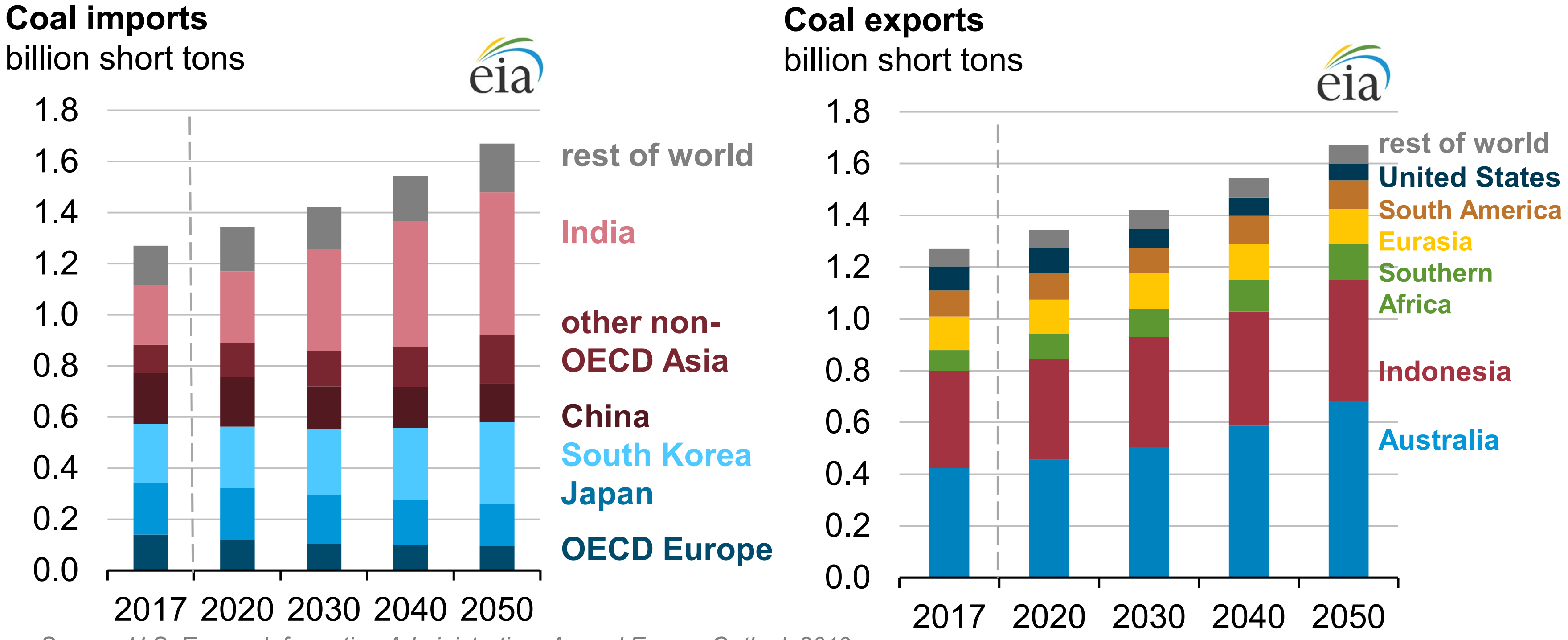






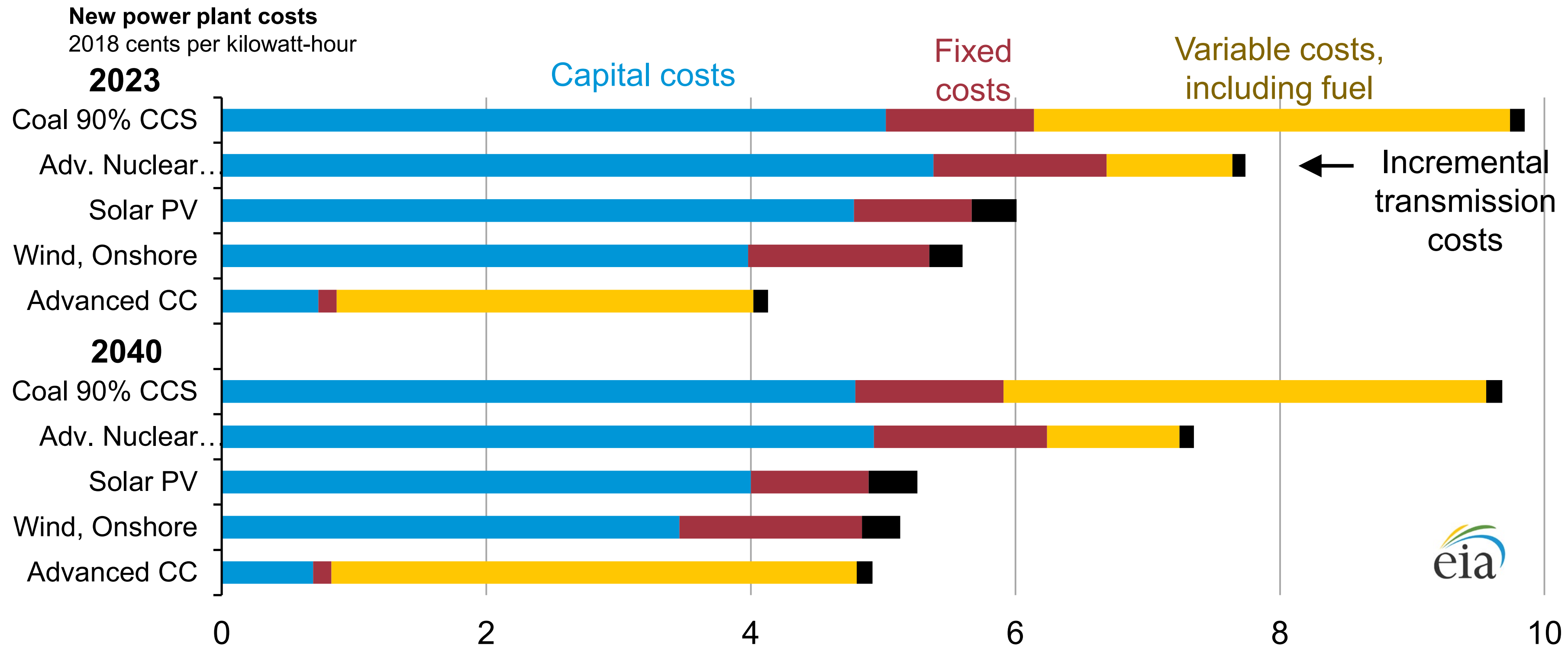
Source: U.S. Energy Information Administration, AEO2019 National Energy Modeling System run REF2019.D1116A.

International seaborne coal trade projected to increase 31% (400 million short tons) in AEO2019 (2017–2050)



Source: U.S. Energy Information Administration, Annual Energy Outlook 2019.

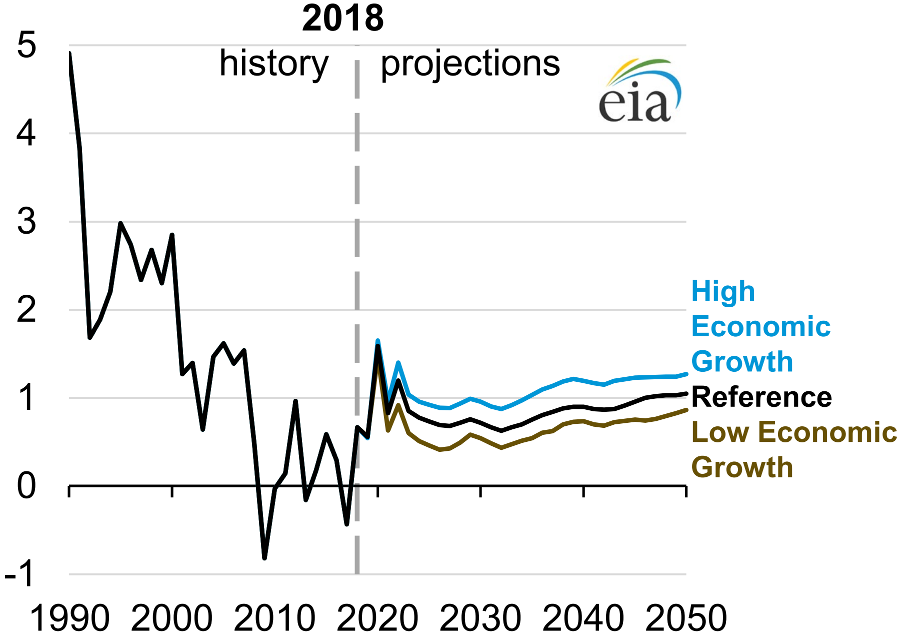
Relatively high levelized cost of electricity for coal prohibits the addition of coal in any case evaluated in AEO2019



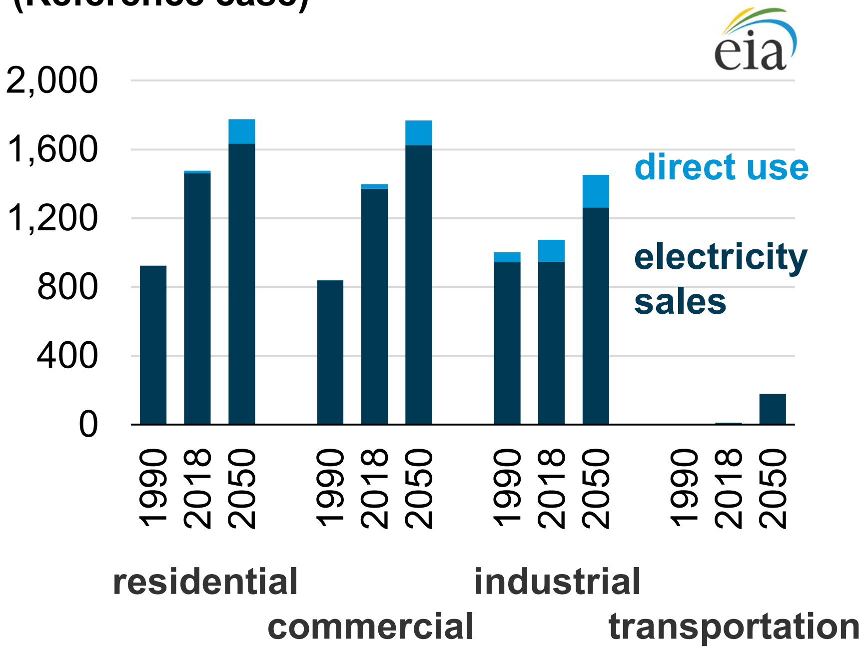
Source: U.S. Energy Information Administration, "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the AEO2019", February 2019, Excerpted from Table 1b (2023) and Table B1b (2040)

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

Electricity use growth rate
percent growth (three-year rolling average)



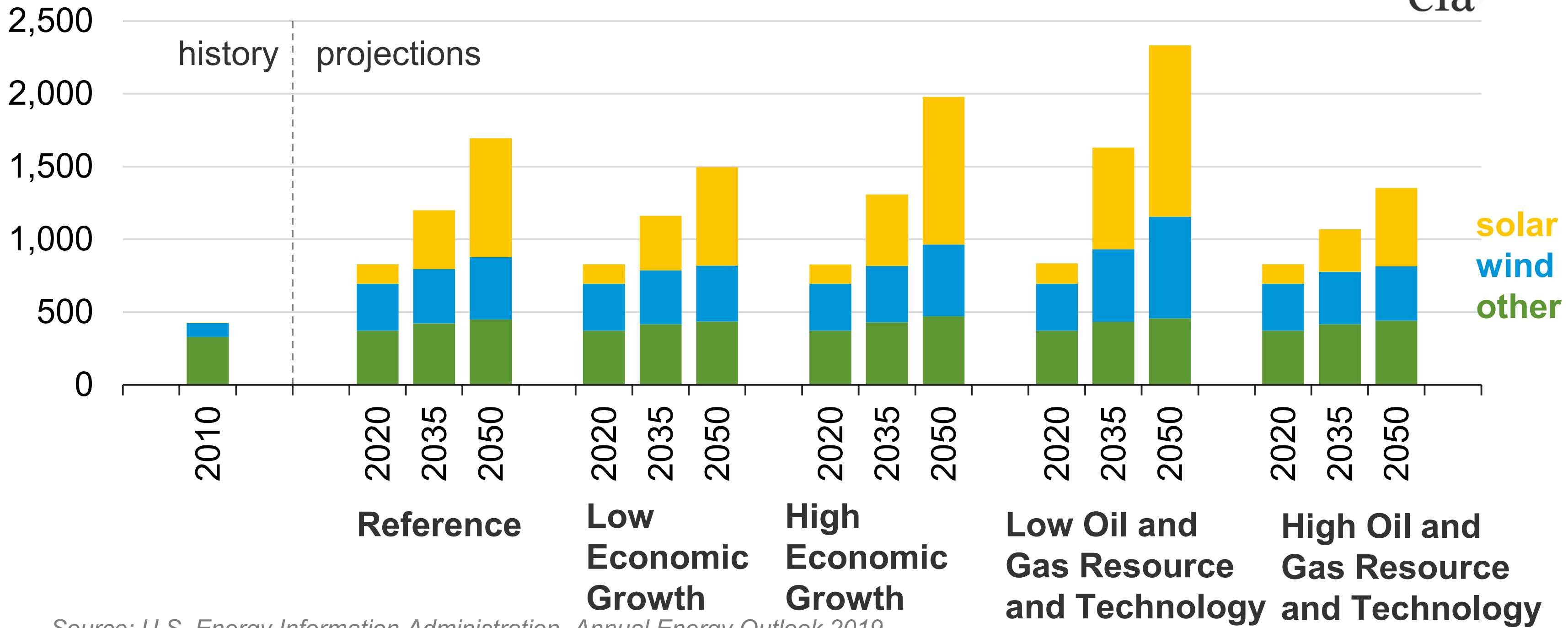
Electricity use by end-use demand sector (Reference case)



Source: U.S. Energy Information Administration, Annual Energy Outlook 2019.

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

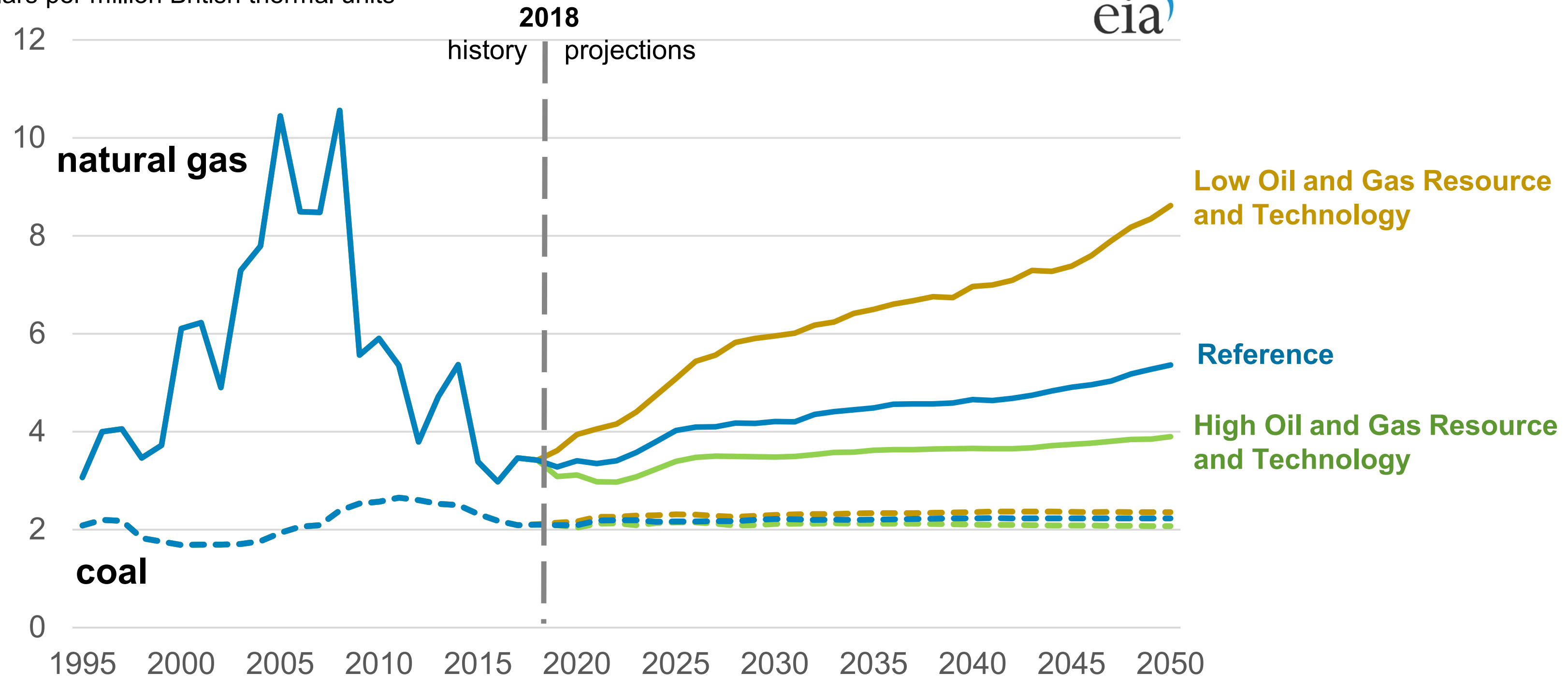
Renewables electricity generation (all sectors) by case
billion kilowatthours



Source: U.S. Energy Information Administration, Annual Energy Outlook 2019.

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

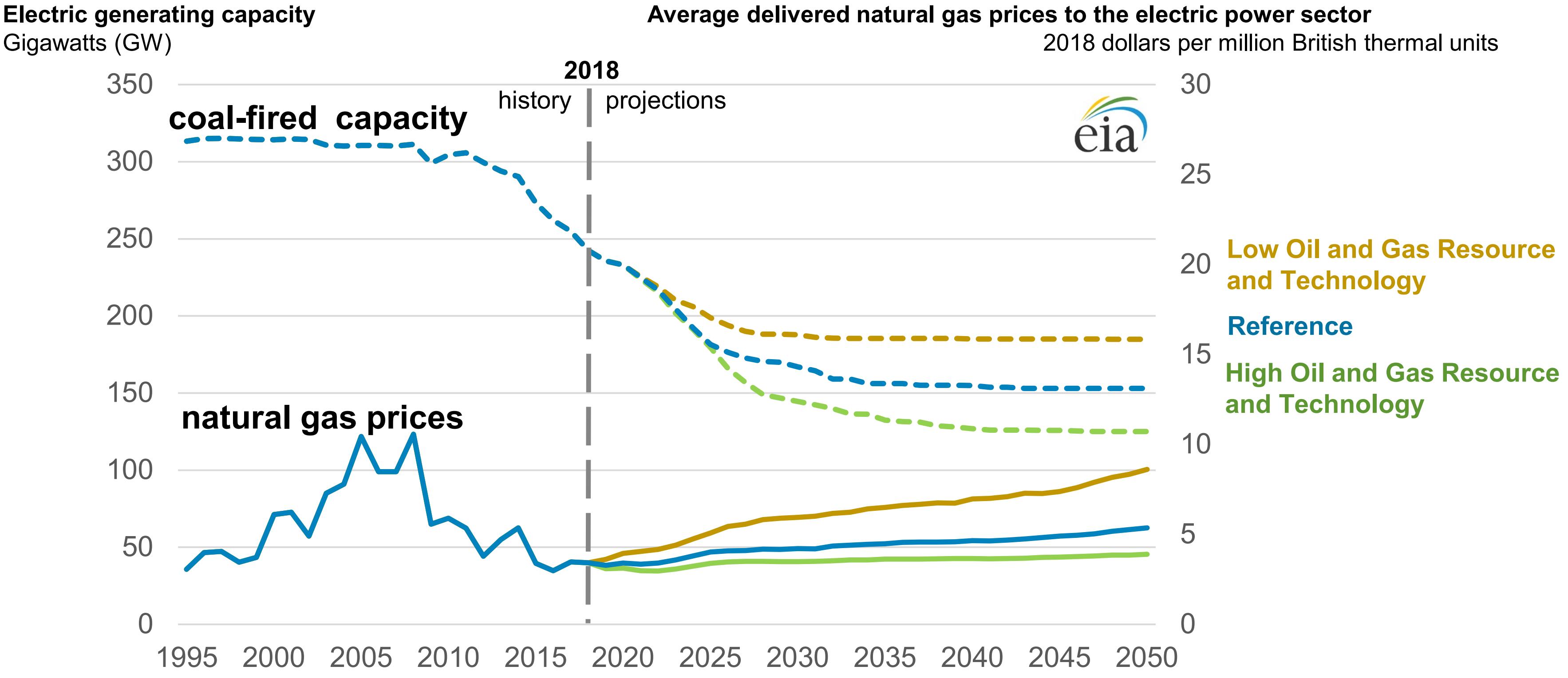
Average delivered fuel prices to the electric power sector
2018 dollars per million British thermal units



Source: U.S. Energy Information Administration, AEO2019 National Energy Modeling System run REF2019.D1116a, hightr.1116a, and lowrt.1116a.

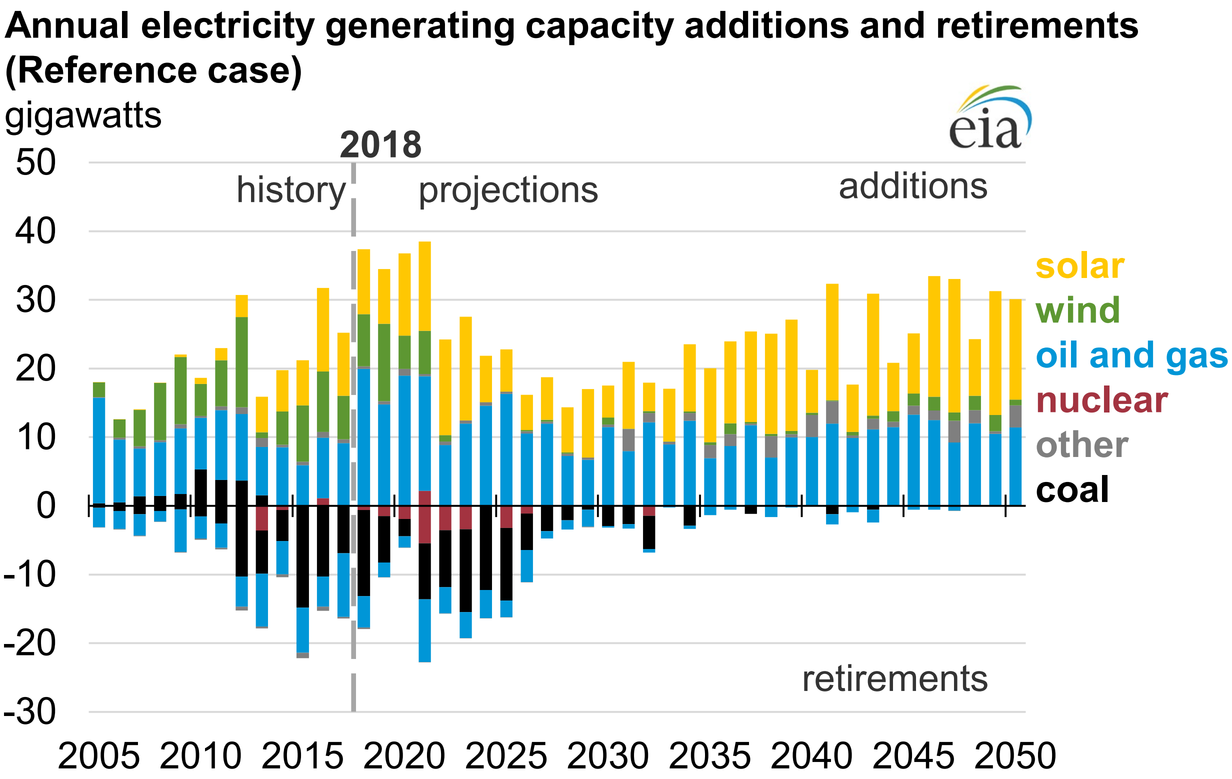
AEO2019 results with emphasis on coal

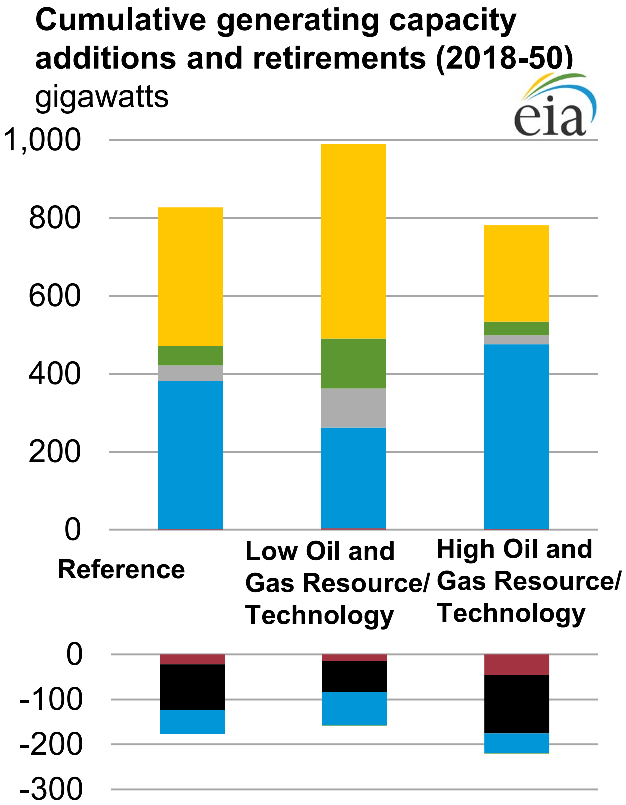
Generating capacity decreases through 2030 in all AEO side cases and is sensitive to the projection for natural gas prices



Source: U.S. Energy Information Administration, AEO2018 National Energy Modeling System run REF2019.D1116a, highrt.1116a, and lowrt.1116a.

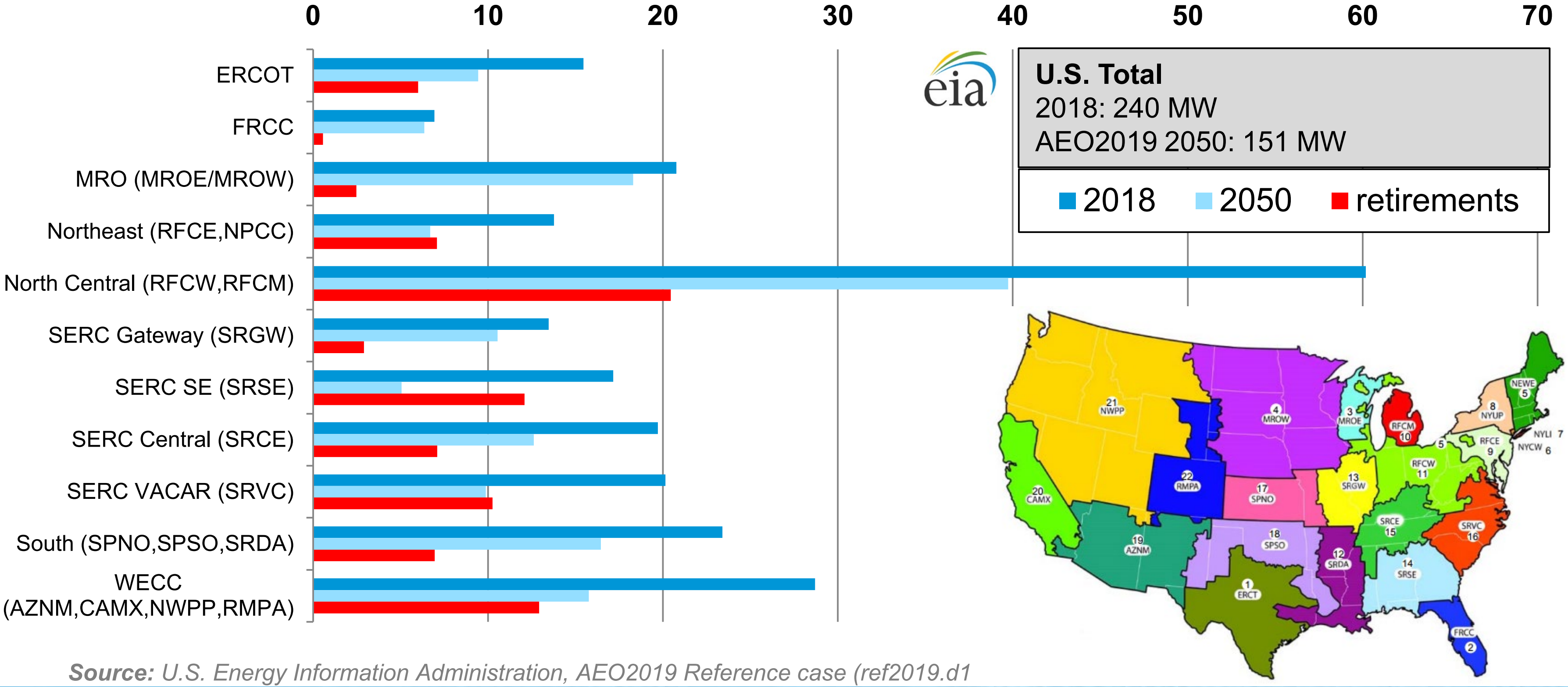
Economics and policy drive changes to electric generation capacity





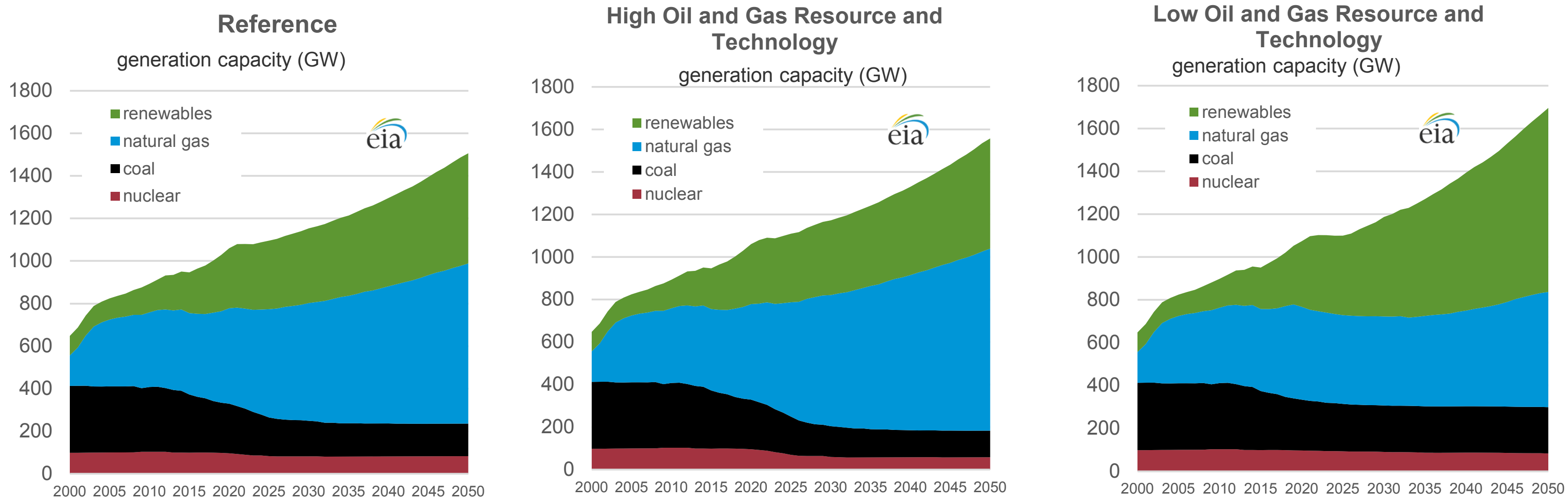
Source: U.S. Energy Information Administration, Annual Energy Outlook 2019.

Net summer coal-fired generating capacity in the electric power sector declines disproportionately by region in the AEO2019 Reference case



Source: *U.S. Energy Information Administration, AEO2019 Reference case (ref2019.d1*

Comparison of electric generating capacity across the Reference and High/Low Oil and Natural Gas Resource and Technology cases

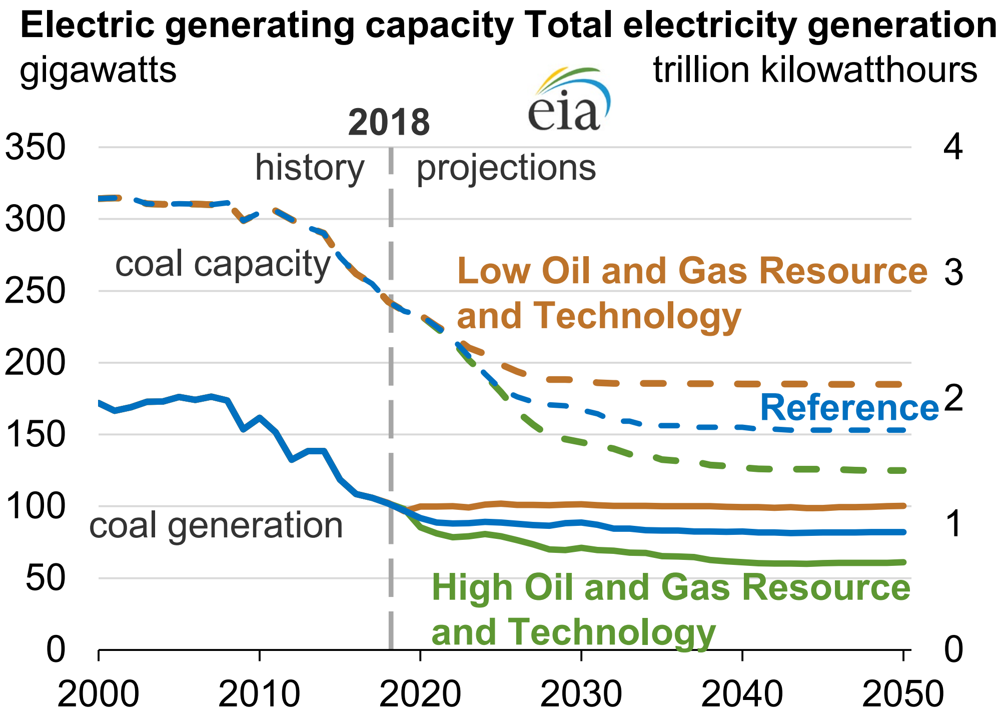


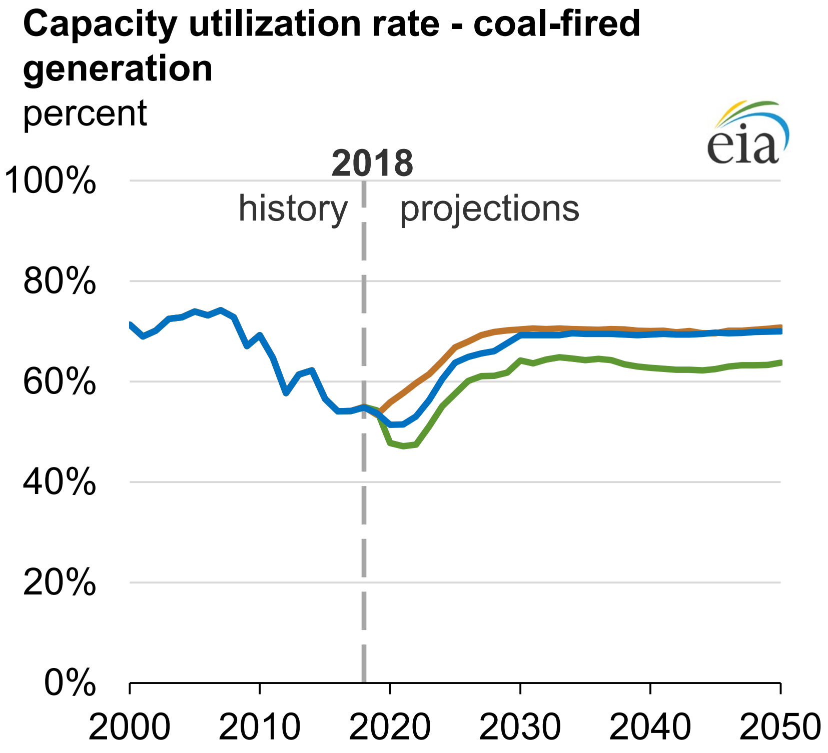
- In the High Oil and Natural Gas Resource and Technology case, coal-fired capacity declines by an additional 28 GW to 125 GW as plentiful low-cost natural gas dominates with 103 GW of additional capacity through 2050. Nuclear also declines by an additional 24 GW.

- In the Low Oil and Natural Gas Resource and Technology case, coal-fired capacity declines by 32 GW declining to 185 GW through 2050. Nuclear capacity increases by 10 GW and renewables increase by and additional 222 GW.

Source: U.S. Energy Information Administration, Annual Energy Outlook 2019 (ref2019.d1116a); .

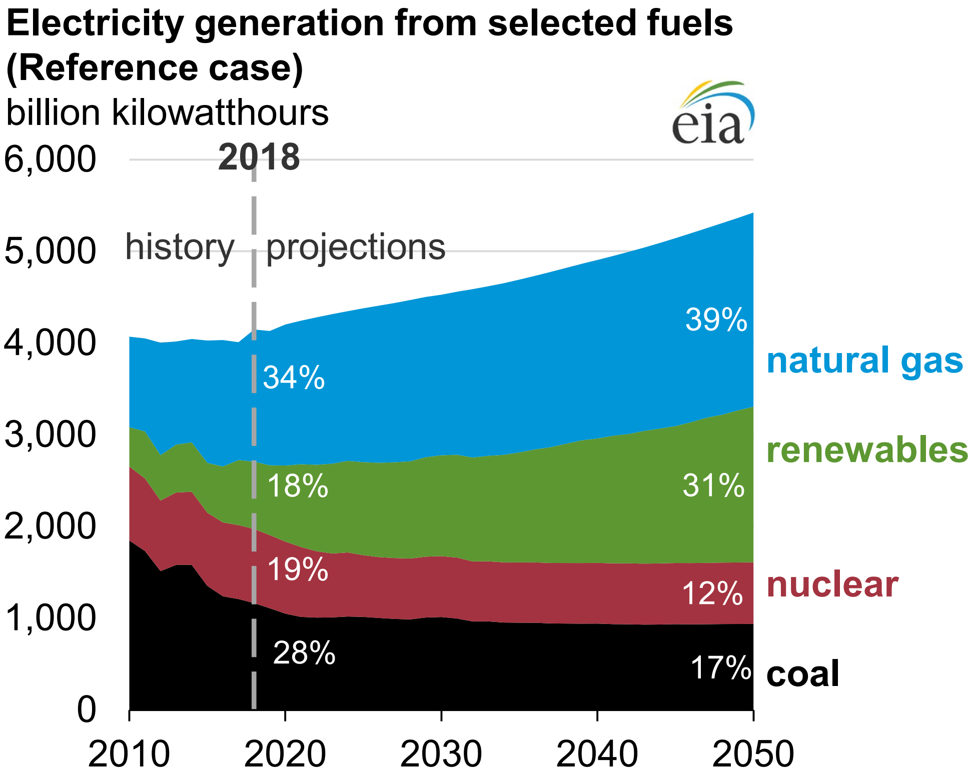
Although coal capacity declines, capacity factors for remaining coal units recover as much as natural gas prices allow

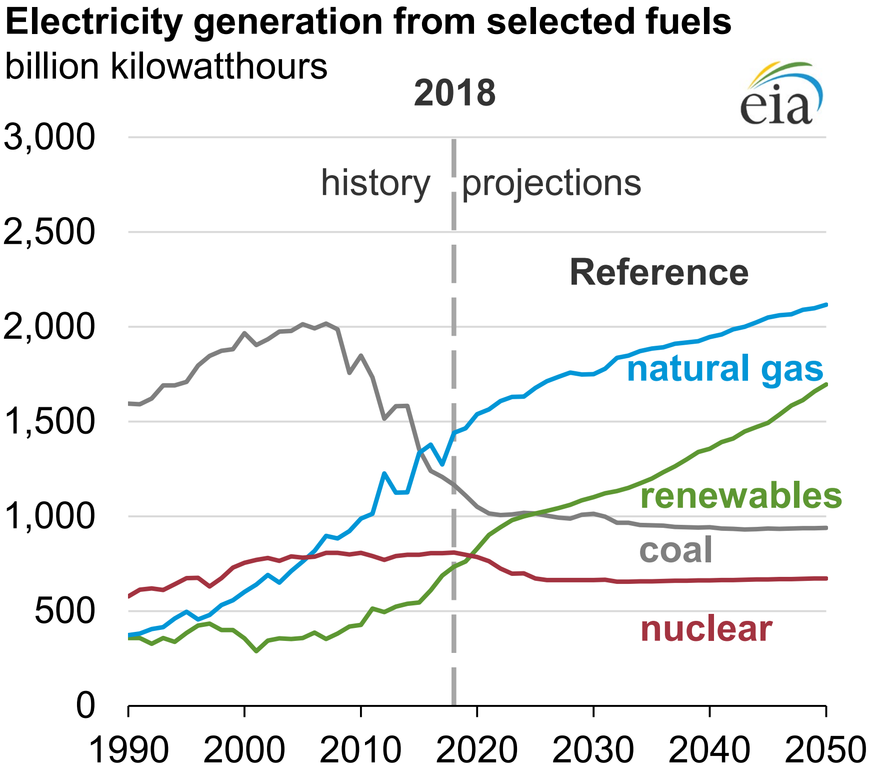




Source: U.S. Energy Information Administration, Annual Energy Outlook 2019.

Electricity generation from natural gas and renewables increases steadily with coal and nuclear projected to remain relatively flat in the AEO2019 Reference case

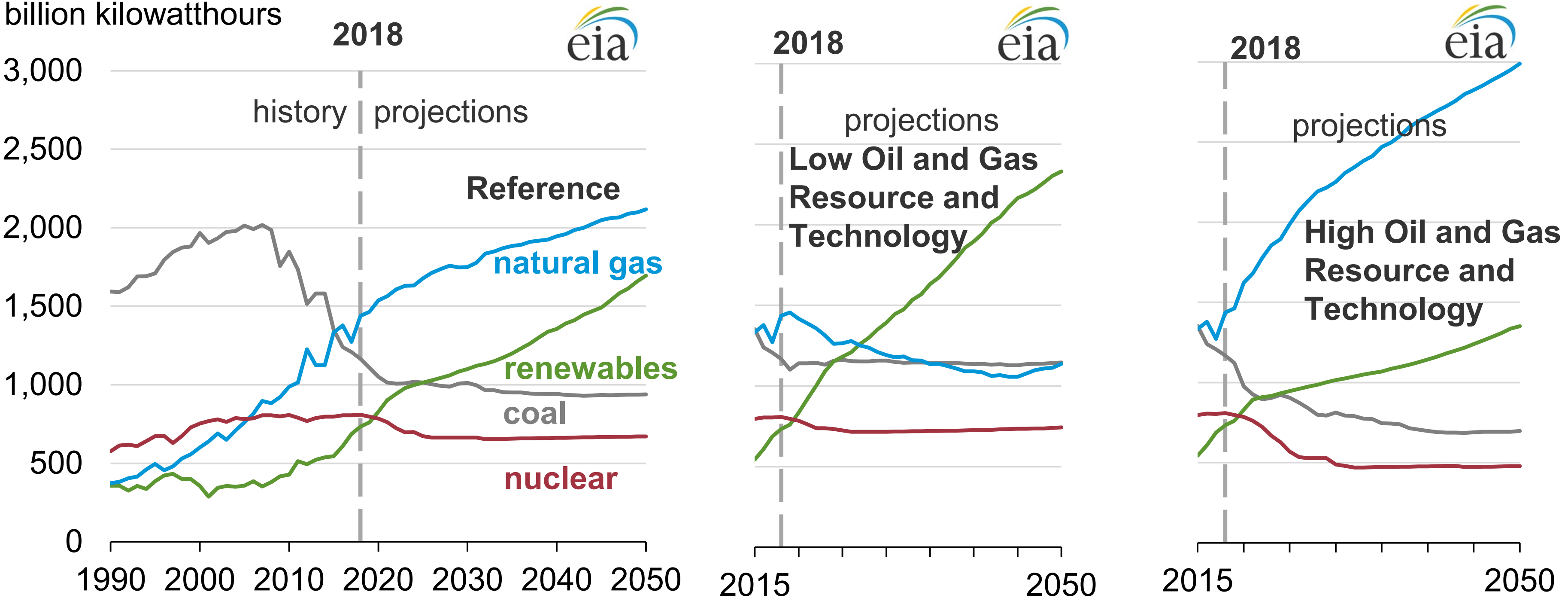




Source: U.S. Energy Information Administration, Annual Energy Outlook 2019.

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

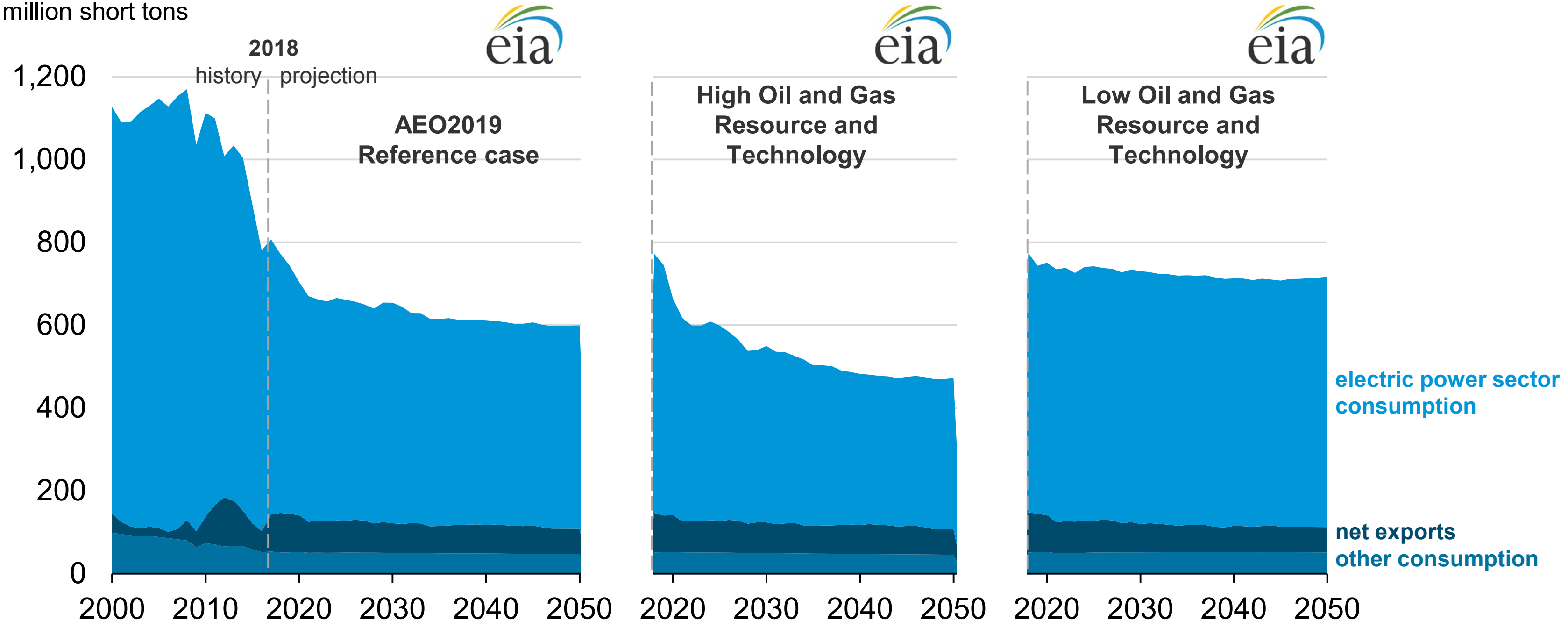
Electricity generation from selected fuels
billion kilowatthours



Source: U.S. Energy Information Administration, Annual Energy Outlook 2019.

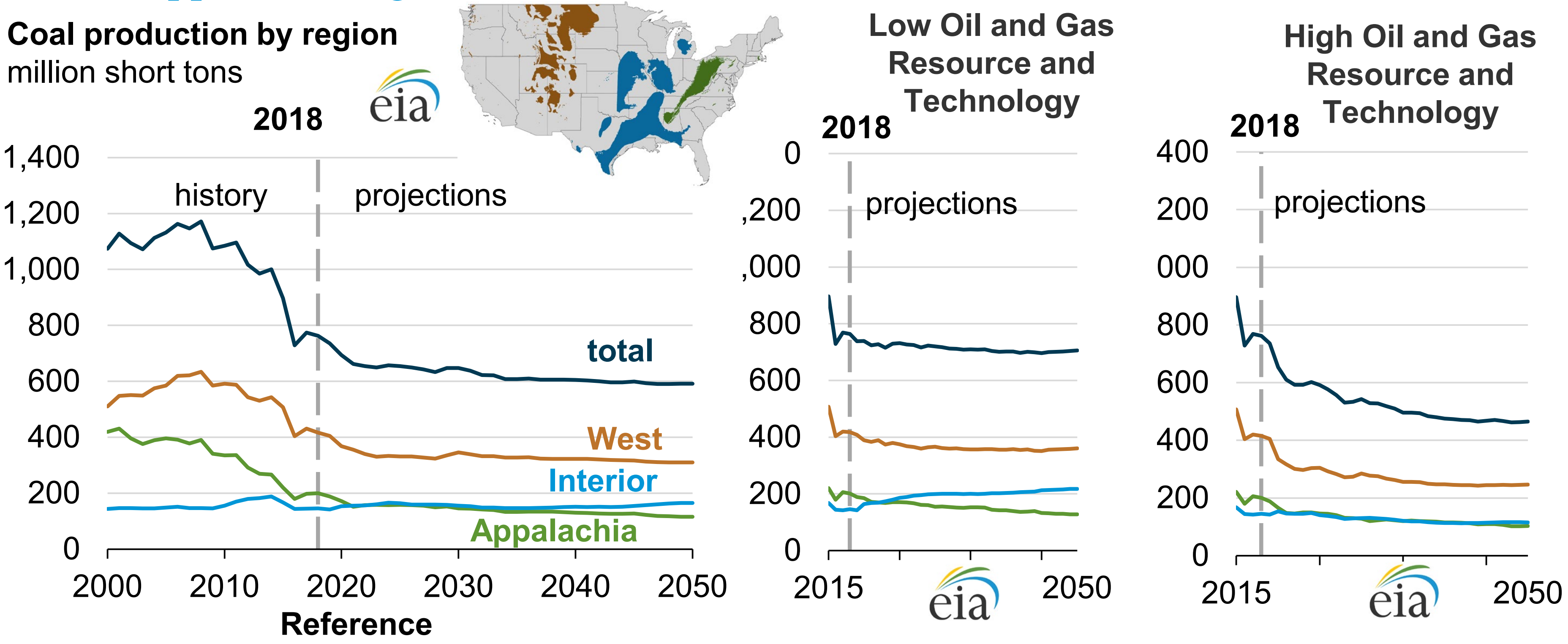
Electricity sector consumption drives total U.S. coal disposition with stable industrial and slowly-increasing export demand

U.S. coal consumption and net exports
million short tons



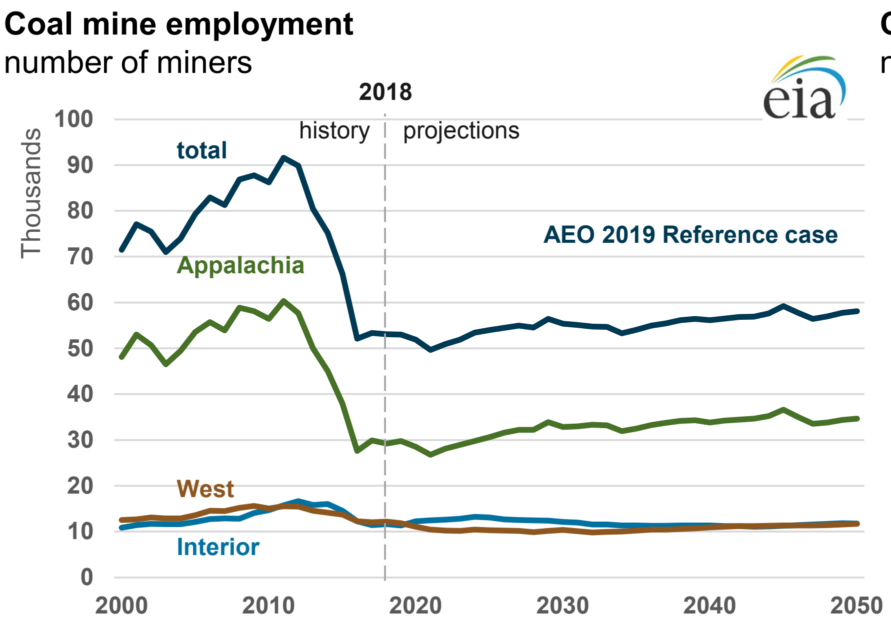
• *Source: U.S. Energy Information Administration, AEO2019 National Energy Modeling System run REF2019.D1116a, highrt.1116a, and lowrt.1116a.*

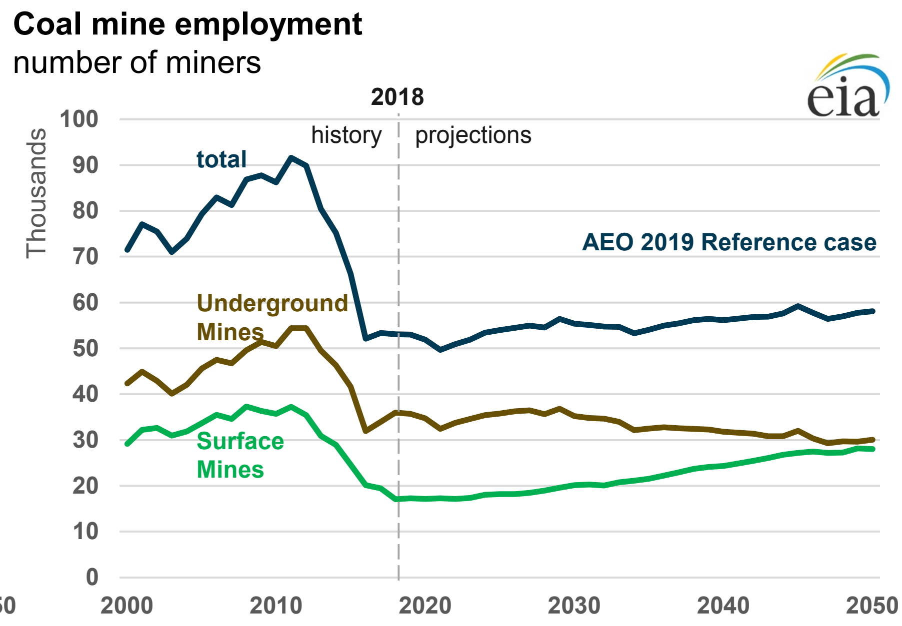
Interior region coal production is projected to increase at the expense of the West and Appalachia regions in the Reference case



Source: U.S. Energy Information Administration, Annual Energy Outlook 2019.

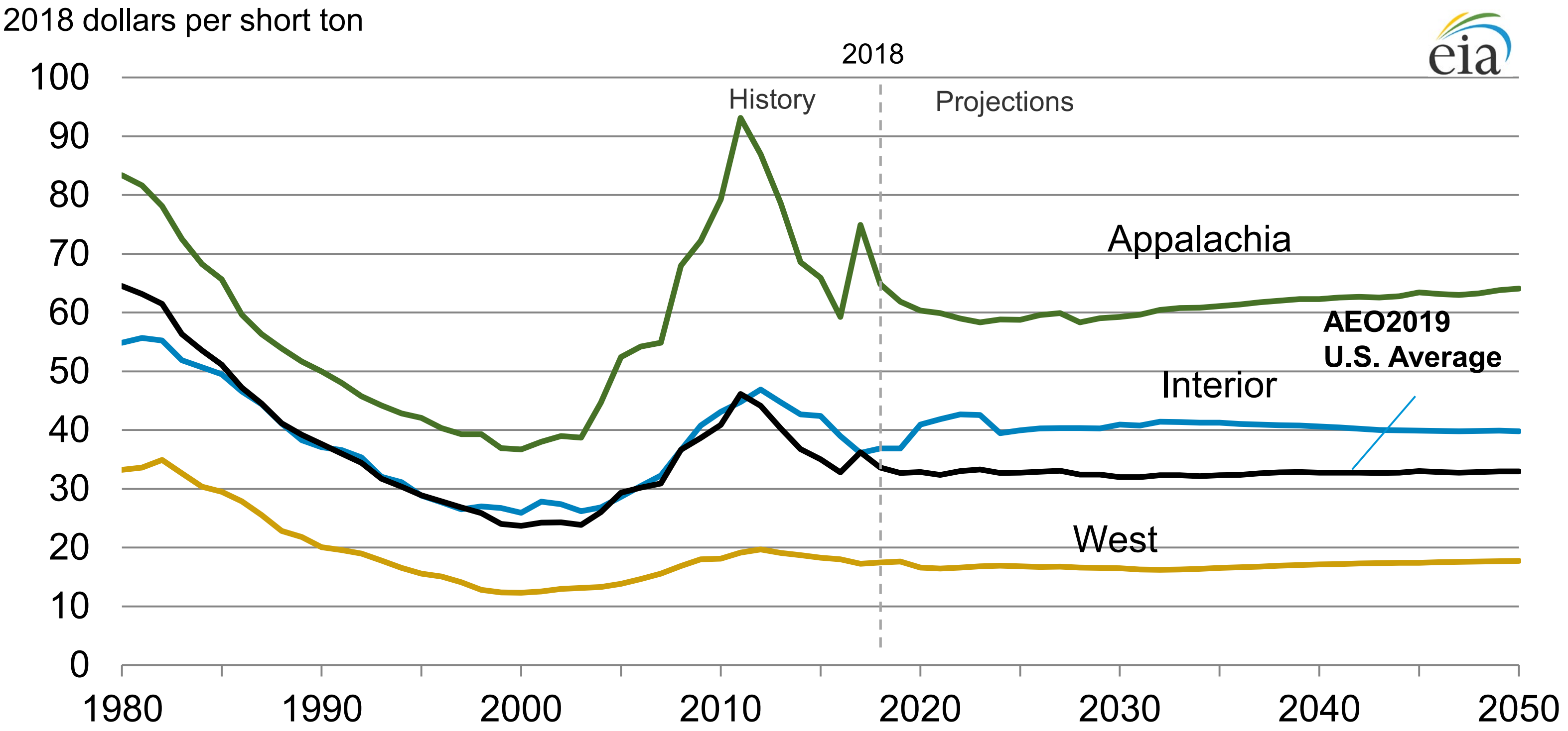
Coal mine employment trends reflect impact of declining labor productivity against backdrop of declining production





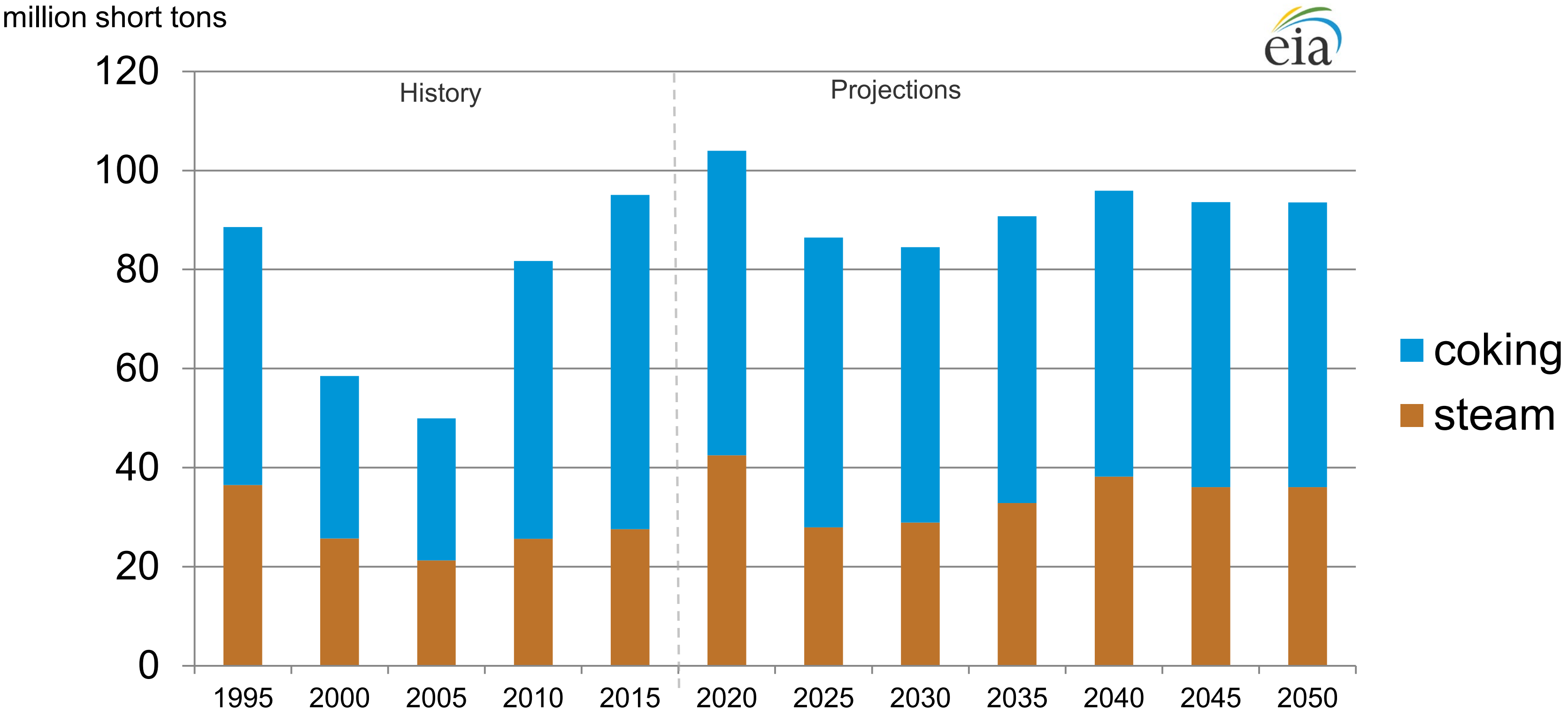
Source: U.S. Energy Information Administration, AEO2019 Reference case (ref2019.d1116a).

Average U.S. minemouth coal prices remain relatively stable in light of declining production volumes



Source: U.S. Energy Information Administration, AEO2019 Reference case (ref2019.d1116a).

U.S. coal exports driven by strong demand for coking coal for steel production



Sources: U.S. Energy Information Administration (EIA); Projections – AEO2019 Reference case (ref2019.d1116a).; History –. Quarterly Coal Report.

Model updates

Coal Market Module (CMM) updates and improvements planned for AEO2020 and beyond

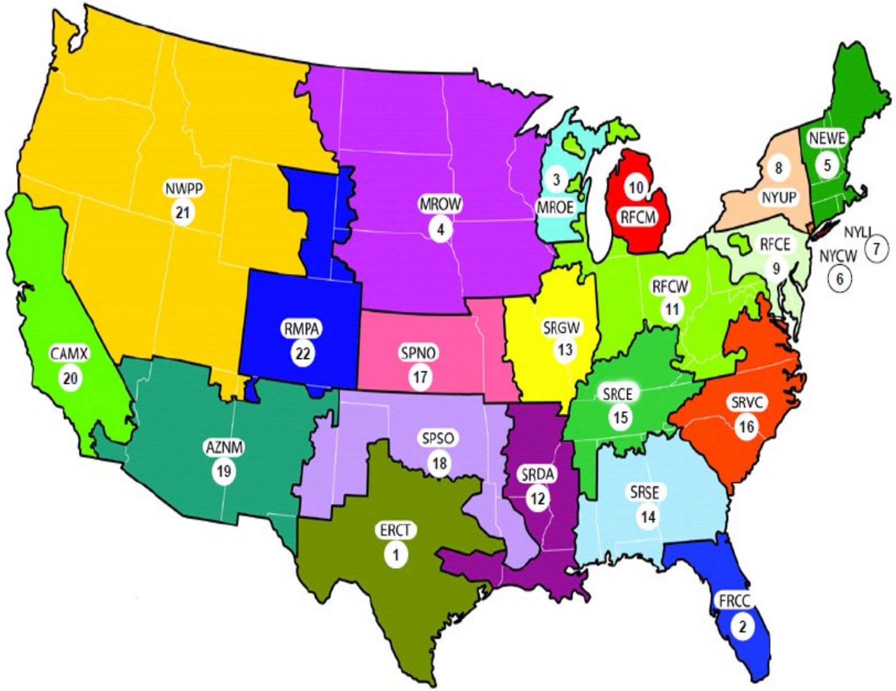
- Implementing 2018 base year updates, including base year coal transportation rates and contracts, and revisiting regional coal export constraints in the CMM
- Progressing on three CMM upgrade priorities
  - Implementing a revised approach to modeling seaborne coal shipping costs in AEO2020
  - Evaluating a revised approach to escalating real domestic coal transportation rates
  - Developing a revised approach for modeling international coal supply curves (ICSC) in the CMM in AEO2021
- Developing an International Coal Market Module (ICMM) in WEPS+
  - Developing a linear programming-based approach using EIA's Global Hydrocarbon Supply Model (GHySMo) platform and taking advantage of efforts to improve the modeling of ICSC and seaborne coal shipping costs
  - Anticipating for inclusion in IEO2020/1 cycle
- Initiating plans for a Short-Term Energy Outlook (STEO) coal forecasting working group in summer 2019

Pending AEO2020 model enhancements to NEMS Electricity Market Module (EMM)

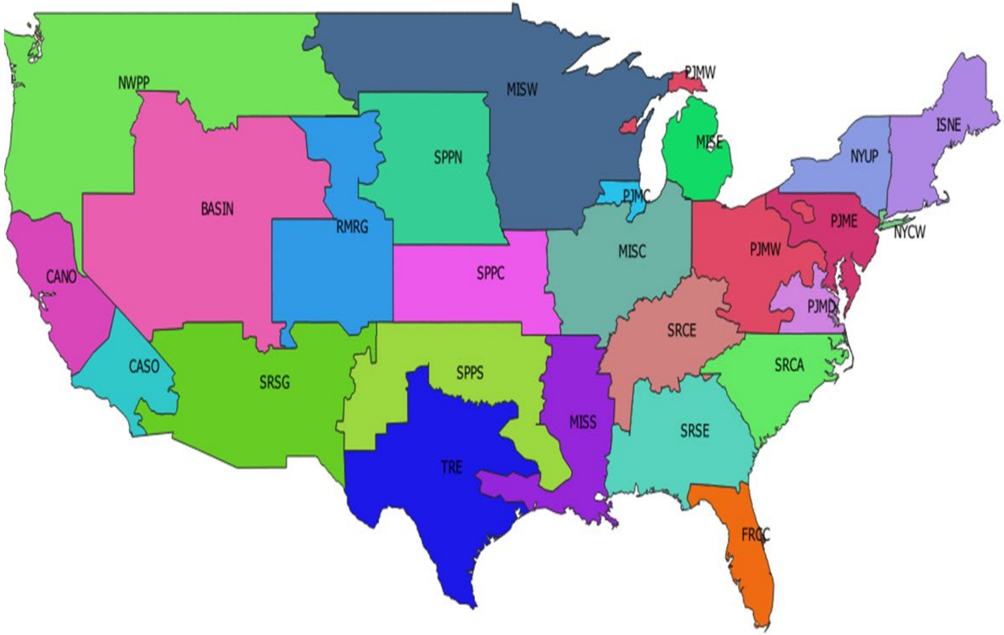
- Regional redefinition of EMM supply regions
- Updated capital cost and performance for new electric generating technologies

What will the new regions look like in EMM?

CURRENT



PROPOSED



Source: Current: U.S. Energy Information Administration, [Assumptions to the Annual Energy Outlook 2019: Electricity Markets Module](). Proposed: Proposed Approach for the EMM Regional Redefinition and Renewable Resource Mapping, On-Location- Oct 15, 2018 (unpublished)

Generation technologies proposed for updated capital cost estimates for AEO2020

EMM Generating Technology Plant Types Proposed			
Fossil/Nuclear			
Fuel Type	**Plant Type description**	**Proposed Configuration**	**Case Description**
Coal	Coal w/o CCS	650 MW Net	Ultra-supercritical coal (NSPS for NOX, Sox, PM, Hg)
Coal	Coal w/Partial Sequestration	650 MW Net	NSPS compliant ultra-supercritical coal (with 30% CCS or other compliance technology)
Coal	Coal w/90% Sequestration	650 MW Net	Ultra-supercritical coal (with 90% CCS)
Gas-Peaking	Internal Combustion Engine	20 MW (4x 5.6 MW)	Internal combustion engine (natural gas or oil-fired diesel)
Gas-Peaking	Conv Combustion Turbine	100 MW, 2 x LM6000	Combustion oil/natural gas turbine
Gas- Baseload	Adv Gas/Oil Comb Cycle	1100 MW, H-Class, 2x2x1	Combined-cycle oil/natural gas turbine
Gas-Baseload	Adv Gas/Oil Comb Cycle	430 MW, H-Class 1x1x1	Combined cycle single shaft
Gas- Baseload	Adv CC w/Sequestration	430 MW, H-Class 1x1x1	Combined-cycle gas turbine (with 90% CCS)
Nuclear	Advanced Nuclear	2 x 1117 MW, PWR	Advanced Nuclear AP 1000
NEW Nuclear	SMR Nuclear	600 MW	Small Modular Reactor (SMR)

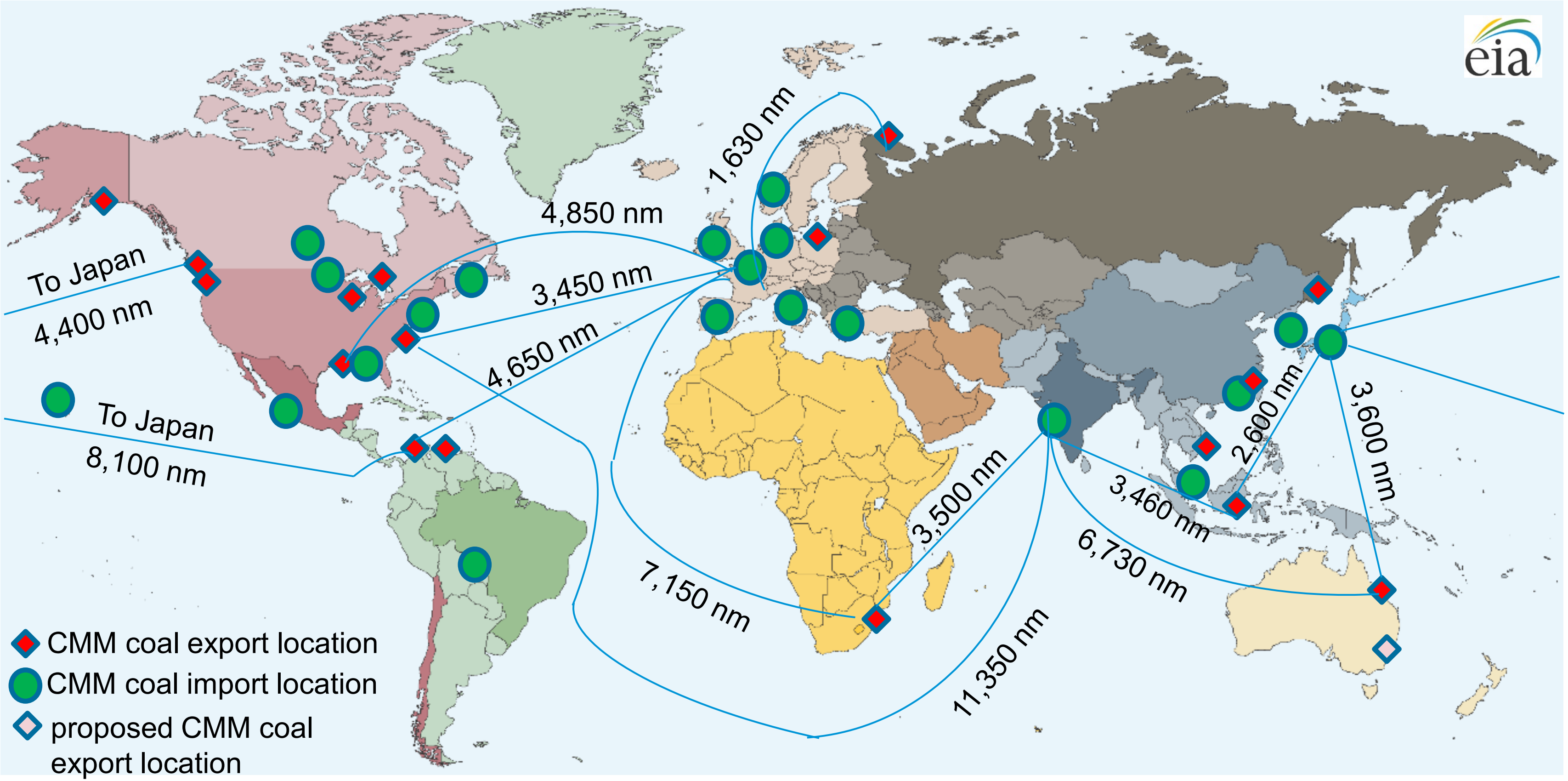
Source: U.S. Energy Information Administration.

Changes to the Coal Market Module: seaborne coal transportation rates

Improving the projections for seaborne coal trade freight rates in the CMM

- Currently, the CMM specifies fixed, annual rates by route exogenously
- EIA worked with Hellerworx, Inc. to suggest an improved methodology
  - Hellerworx, Inc., DOE/EIA Coal Market Module: Coal Transportation Rate Methodology Assessment, September 29, 2017 (Unpublished)
- The proposed method would estimate rates endogenously by major vessel category (Panamax or Cape sizes)
  - Component for costs at sea represented as a function of trip distance, vessel size, average speed, bunker and marine gas oil fuel consumption per day at sea, fuel cost per metric ton, and vessel hire costs per day
  - Component for costs in port represented as a function of days in port, port fees per metric ton, lading tonnes, marine gas oil fuel consumption per day in port, and vessel hire costs per day (note: does **not** include loading and unloading costs – only the vessel costs)
  - Fuel costs by year determined endogenously by other modules in NEMS
  - Daily vessel hire rates in each year determined exogenously based on analyst assessments
- EIA proposes to implement this method in-house in time for AEO2020

Ports and Estimated Shipping Distances for Selected Routes



Stylized example of the proposed seaborne coal trade freight rates in the CMM

Variable	Units	Vessel Type: Panamax	Vessel Type: Cape
Total Cost	$ Per Coal Delivery	**$ 514,506**	**$ 959,466**
Cost Per Thousand Tonne-Miles	*$ Per Tonne-Mile*	*$ 1.99*	*$ 1.83*
Cost Per Metric Tonne	*$ Per Metric Tonne*	*$ 6.95*	*$ 6.40*
Total Cost at Sea	$ Per Coal Delivery	$ 289,506	$ 462,346
Bunker Fuel Cost at Sea	$ Per Coal Delivery	$ 142,593	$ 233,333
Marine Fuel Cost at Sea	$ Per Coal Delivery	$ 6,481	$ 12,963
Vessel Hire Costs at Sea	$ Per Coal Delivery	$ 140,432	$ 216,049
Total Cost in Port	$ Per Coal Delivery	$ 225,000	$ 497,120
Marine Fuel Cost in Port	$ Per Coal Delivery	$ 12,000	$ 21,120
Total Port Costs	$ Per Coal Delivery	$ 148,000	$ 300,000
Vessel Hire Costs in Port	$ Per Coal Delivery	$ 65,000	$ 176,000

Source: Stylized example based on unpublished analysis for EIA by Hellerworx, Inc., DOE/EIA International Coal Supply Curve and Transportation Modeling – Australia Pilot Study, Ocean Freight Forecast & Coal Data Survey Study Methodology and Documentation, September 8, 2016.

Seaborne coal trade freight rate assumptions

Variable	Units	Vessel Type: Panamax	Vessel Type: Cape
Parameters			
Days at Sea	**Days**	**10.8**	**10.8**
Voyage Distance (Example) (F - by Route)	Nautical Miles	3,500	3,500
Daily Distance Traveled	Nautical Miles	324.0	324.0
Average Speed (F)	Knots	13.5	13.5
Hours Per Day (F)	Hours	24	24
Daily Hire Rate (A: User)	**$ Per Day**	**$ 13,000**	**$ 20,000**
Fuel Oil Assumptions			
Bunker Fuel Consumption Per Day at Sea (F)	Metric Tonnes/Day	33	54
Bunker Fuel Oil Cost (A: NEMS)	$ Per Metric Tonne	$ 400	$ 400
Marine Fuel Consumption Per Day at Sea (F)	Metric Tonnes/Day	1	2
Marine Fuel Oil Cost (A:NEMS)	$ Per Metric Tonne	$ 600	$ 600
Marine Fuel Consumption Per Day in Port (F)	Metric Tonnes/Day	4	4
Port Cost Assumptions			
Port Fees Per Delivery (F)	$ Per Metric Tonne	$ 2.00	$ 2.00
Lading Tonnes (F)	Metric Tonnes	74,000	150,000
Days in Port (F)	Days	5.00	8.80

(F) = Fixed Parameter Value; (A: User) = Annual, User-Specified Values; (A: NEMS) = Annual Values from Other NEMS Module

Source: Stylized example based on unpublished analysis for EIA by Hellerworx, Inc., DOE/EIA International Coal Supply Curve and Transportation Modeling – Australia Pilot Study, Ocean Freight Forecast & Coal Data Survey Study Methodology and Documentation, September 8, 2016.

Seaborne coal trade freight rates: costs at sea

Variable	Units		Vessel Type: Panamax		Vessel Type: Cape
Total Cost at Sea	**$ Per Coal Delivery**	**$**	**289,506**	**$**	**462,346**
Cost Per Thousand Tonne-Miles	*$ Per Tonne-Mile*	*$*	*1.12*	*$*	*0.88*
Cost Per Metric Tonne	*$ Per Metric Tonne*	*$*	*3.91*	*$*	*3.08*
Bunker Fuel Cost at Sea	**$ Per Coal Delivery**	**$**	**142,593**	**$**	**233,333**
380 CST High Sulfur Heavy Fuel Oil	Metric Tonnes		356		583
Bunker Fuel Consumption Per Day at Sea	Metric Tonnes/Day		33		54
Days at Sea	Days		10.8		10.8
Bunker Fuel Oil Cost	$ Per Metric Tonne	$	400	$	400
Marine Fuel Cost at Sea	**$ Per Coal Delivery**	**$**	**6,481**	**$**	**12,963**
Marine Gas Oil (MGO)-DIESEL	Metric Tonnes		11		22
Marine Fuel Consumption Per Day at Sea	Metric Tonnes/Day		1		2
Days at Sea	Days		10.80		10.80
Marine Fuel Oil Cost	$ Per Metric Tonne	$	600	$	600
Vessel Hire Costs at Sea	**$ Per Coal Delivery**	**$**	**140,432**	**$**	**216,049**
Daily Hire Rate	$ Per Day	$	13,000	$	20,000
Days at Sea	Days		10.8		10.8

Source: Stylized example based on unpublished analysis for EIA by Hellerworx, Inc., DOE/EIA International Coal Supply Curve and Transportation Modeling – Australia Pilot Study, Ocean Freight Forecast & Coal Data Survey Study Methodology and Documentation, September 8, 2016.

Seaborne coal trade freight rates: costs in port

Variable	Units	Vessel Type Panamax		Vessel Type Cape	
Total Cost in Port	**$ Per Coal Delivery**	**$**	**225,000**	**$**	**497,120**
Cost Per Thousand Tonne-Miles	*$ Per Tonne-Mile*	*$*	*0.87*	*$*	*0.95*
Cost Per Metric Tonne	*$ Per Metric Tonne*	*$*	*3.04*	*$*	*3.31*
Marine Fuel Cost in Port	**$ Per Coal Delivery**	**$**	**12,000**	**$**	**21,120**
Marine Gas Oil (MGO)-DIESEL	Metric Tonnes		20		35
Marine Fuel Consumption Per Day in Port	Metric Tonnes/Day		4		4
Days in Port	Days		5.00		8.80
Marine Fuel Oil Cost	$ Per Metric Tonne	$	600	$	600
Total Port Costs	**$ Per Coal Delivery**	**$**	**148,000**	**$**	**300,000**
Port Fees Per Delivery	$ Per Metric Tonne	$	2.00	$	2.00
Lading Tonnes	Metric Tonnes		74,000		150,000
Vessel Hire Costs in Port	**$ Per Coal Delivery**	**$**	**65,000**	**$**	**176,000**
Daily Hire Rate	$ Per Day	$	13,000	$	20,000
Days in Port	Days		5.00		8.80

Source: Stylized example based on unpublished analysis for EIA by Hellerworx, Inc., DOE/EIA International Coal Supply Curve and Transportation Modeling – Australia Pilot Study, Ocean Freight Forecast & Coal Data Survey Study Methodology and Documentation, September 8, 2016.

Plan for implementing freight rate framework for seaborne coal in the CMM

- EIA staff will work to implement this approach in CMM to include in the AEO2020, using endogenous fuel prices within NEMS
- EIA has determined a matrix of distances and assigned a vessel type for each route in the model
- Historic daily hire rates will be reviewed and calibrated to reported freight rates to establish a general long-term trajectory for annual values
- Feedback from the working group will be addressed during the implementation
- Model documentation and assumptions will be updated accordingly

Any questions on the proposed approach for modeling seaborne coal transportation costs?

- The projections will depend to a significant degree on the projection of daily hire rates in the model framework. What approaches should EIA consider for projecting daily hire rates?

- Should EIA incorporate measures of technological improvement over time, such as improvement in fuel consumption or vessel size?

Changes to the Coal Market Module: coal transportation rate escalation

Taking a fresh look at modeling coal transportation rate escalation in times of declining domestic rail volumes

- EIA worked with Hellerworx, Inc. to examine EIA's existing approach and to recommend improvements in light of declining coal production volumes shipped in the United States
  - Hellerworx, Inc., "DOE/EIA Coal Market Module: Coal Transportation Rate Methodology Assessment," September 29, 2017 (Unpublished)

- Current econometric approach to rate escalation would be replaced by a share-weighted approach with diesel fuel costs accounted for directly

- EIA staff also reviewed the specification of Tier II rates in the model to evaluate an alternative approach suggested by Hellerworx

- EIA is proposing to implement the Hellerworx approach to rate escalation in-house by the AEO2021 cycle

Why are coal transportation rates important?

- Electric power consumption represents 90% of all coal deliveries to coal users in the United States, with approximately 70% delivered in whole or in part by rail
- The cost of coal transportation averaged an estimated 41% in 2017 to electric power consumers based on survey Form EIA-923 data
- Long-term escalation at 1% per year would result in 35% higher rates in 30 years, or about 14% higher delivered coal costs assuming about a 41% cost share, e.g., the difference between $2.25/MMBtu and $2.57/MMBtu
- In increasingly competitive markets, such changes could have noticeable impacts on coal retirements and capacity factors

Sources: U.S. Energy Information Administration, Today in Energy, August 3, 2018, U.S. coal shipments reach their lowest levels in years, Primary Contributor: Elias Johnson. Also, U.S. Energy Information Administration, July 17, 2018 Transportation Costs to Electric Power Sector.

How are base year coal transportation rates estimated?

- Base year coal transportation rates, aggregated across all modes, are estimated between each coal supply curve and each coal demand region and plant group type
  - Base year rates are currently estimated as the difference between delivered coal prices reported by electric utility generators on survey Form EIA-923 and minemouth coal prices provided on Form EIA-7A
  - Coal supply curves are delineated by coal supply region, coal type, mine type, and sulfur class
  - Plant groups within each coal demand region are delineated by pollution control configuration
  - Base year rates are adjusted to remove the estimated impact of railroad fuel surcharges before the real escalation rates are applied, and they are added back after the adjusted base year rates have been adjusted for second-tier rate adders and escalated
- Second-tier rate adders adjust rates to account for shipping distances within a coal demand region, as well as incremental costs associated with upgrading a coal unit to burn PRB coal
  - Increased shipping distances are accounted for by adjusting transportation rates to the difference between the estimated shipping distance and the geographic centroid for the relevant coal demand region
  - Assumed adder of $0.10/MMBtu accounts for incremental capital for coal pulverization volumes and boiler modifications, and operating costs from changes in slagging/fouling and heat rate impacts necessary to burn PRB coal

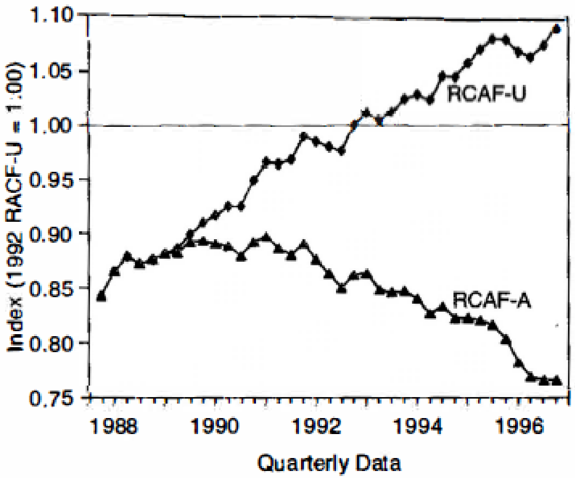
Sources: U.S. Energy Information Administration, Coal Market Module of the National Energy Modeling System: Model Documentation 2005 (April) and 2009 (June), Appendix D.

How have coal transportation rate escalation methods evolved? (1 of 2)

- Before 1997, EIA relied on a regression model to estimate real, inflation-adjusted escalation rates based on the American Association of Railroads' Railroad Cost Recovery Index, with separate escalators for East and West

- In 1997, EIA adjusted its econometric approach to incorporate the effects of rail productivity improvements on rail costs
  - Corrected for the widening gap between the input cost trends and trends in actual rates
  - Modeled the real Producer Price Index (PPI) for coal transportation as a function of the real wage cost index, the real price of distillate fuel, the real producer price index for transportation equipment, and a time trend to account for productivity; benchmarked to the base year
  - A parameter was included that allowed user to adjust the effects of the productivity trend variable over time

Figure 4. Trends in Unadjusted and Adjusted Railroad Cost Adjustment Factors, 1987-1996



Source: Association of American Railroads, *Association of American Railroad Cost Indexes* (Washington, DC, September 1996 and prior issues).

Source: Watkins, Jim, "Forecasting Annual Energy Outlook Coal Transportation Rates," Issues in Midterm Analysis and Forecasting 1997, DOE/EIA-0607(97), (Washington, DC, Energy Information Administration), July 1997, pp. 75-82.

How have coal transportation rate escalation methods evolved? (2 of 2)

- In 2005, EIA incorporated differentiated East/West escalators to account for longer shipping distances in the West, transformed the PPI for transportation into a User Cost of Capital for the railroad equipment variable, and used ton-miles per employee to model productivity
  - Both eastern and western deliveries were modeled as functions of (2SD-adjusted) productivity and the user-cost of capital, but the function for eastern deliveries also included contract duration, while western deliveries included a distance variable
  - The UCC adjusts the Producer Price Index (PPI) for Rail Equipment (RE) as a function of the cost of capital tied up in rail as a function of the real AA utility bond rate premium, the cost of depreciation at a rate of 10%, and the change in the PPI-RE
- In 2009, EIA functions for East/West were modified further based on additional analysis
  - The East index function substituted diesel fuel price for contract duration; diesel fuel prices are zeroed out in the Eastern econometric projection equation to avoid double-counting the effect of fuel surcharges
  - The West index function substituted gross capital investment by Class I railroads for UCC and substituted the western share of coal demand for distance
  - Productivity is assumed to stay flat reflecting an assumption that changes in productivity are not passed on to shippers

Sources: U.S. Energy Information Administration, Coal Market Module of the National Energy Modeling System: Model Documentation 2005 (April) and 2009 (June), Appendix D.

Summary of coal the current transportation rate escalation method

Current method

EIA-923/7A

First Tier
- Base Year Transportation Rates
- Remove Estimated Fuel Surcharges

Second Tier
- Adjust Cost for Shipping Distances
- Add Cost for 1st Use of Sub-Bit Coal

Adj. Base Year Transportation Rates

Apply Regional Escalation Indices

Econometric Functions

East
- Railroad Productivity
- User cost of capital
- Diesel fuel price

West
- Railroad Productivity
- Investment
- West U.S. Mkt. Share

Escalated Transportation Rates

Apply Annual Fuel Surcharges

Modeled Transportation Rates

What are the differences between the rate escalation methods?

- Current method
  - Estimates separate coal transportation rate escalators for eastern and western coal shipments
  - Applies to all modes of coal transport
  - Uses econometric model to estimate the relationship between the projected inputs
    - East modeled as a function of rail productivity, the User Cost of Capital, and diesel fuel prices
    - West modeled as a function of rail productivity, investment, and the western share of U.S. coal shipments
    - User Cost of Capital is based on the Producer Price Index (PPI) for railroad equipment, a proxy for interest rates based on the AA Utility Bond Rate and 3% risk premium, and the estimated annual depreciation (10%)
  - Has separate accounting for fuel cost adjustments

- Proposed method
  - Estimates single, national transportation rate escalation profile using rail as a proxy for other modes of transportation
  - Applies to all modes of coal transport
  - Uses a structural approach to weight key projected cost and productivity inputs
    - Weight fuel, labor, and equipment cost percentage changes by the latest component weightings for the rail industry published by the American Association of Railroads (AAR) adjusted for EIA's outlook for diesel fuel prices
    - Add 50% of estimated average, annual STB productivity improvements (%) over the past 10 years
    - Weights are fixed parameter inputs for the duration of the projections
  - Eliminates separate fuel cost adjustments

Comparison of coal transportation rate escalation methods

Current method

EIA-923/7A

First Tier

- Base Year Transportation Rates
- Remove Estimated Fuel Surcharges

Second Tier

- Adjust Cost for Shipping Distances
- Add Cost for 1st Use of Sub-Bit Coal

Adj. Base Year Transportation Rates

Apply Regional Escalation Indices

Econometric Functions

East
- Railroad Productivity
- User cost of capital
- Diesel fuel price

West
- Railroad Productivity
- Investment
- West U.S. Mkt. Share

Escalated Transportation Rates

Apply Annual Fuel Surcharges

Modeled Transportation Rates

Proposed method

Base Year Transportation Rates

Adjust Cost for Shipping Distances

Add Cost for 1st Use of Sub-Bit Coal

Adj. Base Year Transportation Rates

Apply National Escalation Indices
- Calculate the cost component-weighted real escalation factor, across Fuel, Labor, and Equipment/Other indices
- Subtract share of passed-through rail productivity gains to calculate annual escalation rates

Modeled Transportation Rates

How are the cost component weights derived in the proposed method?

- Cost component weights in 2017 from AAR were 35.0% for labor, 13.4% for fuel, and 51.6% for equipment and other costs based on 2015 data from AAR*
- Component weights adjusted for AEO2017 projected prices were 33% for labor, 18.3% for fuel, and 48.7% for equipment and other costs
- Adjust weights to reflect AEO projections for historical and projected diesel fuel price to the transportation sector (diesel prices) – example based on AEO2017 ($2016)
  - **Adjusted Fuel Weight** = AAR Value –Fuel (13.4%) x Average AEO2017 projected diesel prices from 2017–2050 ($3.76/gallon) x AEO2017 2015 diesel price ($2.76/gallon) = 13.4% x 1.362 = **18.3%**
  - **Allocation Amount** = Adjusted Fuel Weighting (18.3%) – AAR Value (13.4%) = **4.9%**
  - **Allocation Share-Labor** = AAR Value-Labor (35%) / [AAR Value-Labor + AAR-Value-Equip (51.6%)] = 35% / 86.6% = **40.4%**
  - **Adjusted Labor Component Weight** = AAR Value-Labor (35%) – [Allocation Amount (4.9%) x Allocation Share-Labor (40.4%)] = 35.0% - 2.0% = **33.0%**
  - **Adjusted Equipment/Other Component Weight** = 100% - Adjusted Fuel Weighting (18.3% - Adjusted Labor Component Weight (33%) = **48.7%**

Source: Association of American Railroads (AAR), Rail Cost Indexes, RCAF Quarterly Filings & Decisions.

How would the cost component input variables be projected under the proposed method?

- Diesel fuel prices to the transportation sector would be projected endogenously based on historical and projected values in NEMS to adjust the fuel weighting
- Labor costs would be projected based on the performance of the BLS Employment Cost Index during the most-recent, 10-year period available*
  - Hellerworx analysis indicated that the BLS index increased at an average rate of 2.1% per year from 2006Q4 to 2016Q4, compared with the BEA GDP-IDP average inflation rate of 1.6% during the same period, suggesting a 0.5% rate of real increase
  - Hellerworx recommended the BLS index instead of the AAR Labor Index because the AAR index showed a large discontinuity between pre- and post-recession periods compared with the BLS index
  - Hellerworx also suggested that the unionized rail transportation sector should be able to secure wage increases in line with the private sector on average over the long-term
- Equipment/other costs would be projected to increase at the general rate of inflation, i.e., constant in real dollar terms

**BLS Series ID CIS2010000000000I, which tracks the cost of wages, salaries, and benefits for all private sector workers in the United States.*

How would railroad productivity trends be projected and accounted for in the proposed method?

- Rail productivity would be based on the estimated, average productivity gains published by the Surface Transportation Board (STB) during the most-recent, 10-year period available
  - Hellerworx estimated an average annual productivity gain of 1.4% more than the 2006-2015 period
  - This gain was 0.8% from 2006-2010 and 2.0% from 2011 to 2015
- Half of estimated rail productivity improvements would be passed to coal shippers under the proposed method (0.7% per year)
  - Hellerworx believed that railroads will be strongly pressured to pass along a portion of gains to customers to remain competitive in an environment of decreasing coal demand in a declining market for coal transportation
  - Value subtracted from the weighted cost component calculations to determine the national escalation factor in each year

How does this compare to the Surface Transportation Board's (STB) All-Inclusive Index?

RCAF Variable	2017 Share	AAR Short-Term Escalator Basis
Labor	34.8%	Sector analysis of subcomponents for rail sector
Fuel	12.9%	Ultra-Low Sulfur Diesel Fuel referenced, but otherwise, based on a survey of rail purchasers and petroleum experts
Materials & Supplies	4.9%	Not clear, but references change in prices for Metal Products and Misc. Products
Equipment Rentals	5.7%	Price index for Industrial Commodities less Fuel and Related Products and Power (PPI-LF)
Depreciation	15.7%	Power Price Index for Railroad Equipment (PPI-RE)
Interest	2.1%	Interest rates for 10- and 30-year U.S. Treasury Bonds are referenced, but the latest historical value based on annual reports from railroads is carried forward
Other	23.%	Price index for Industrial Commodities less Fuel and Related Products and Power (PPI-LF)

Source: American Association of Railroads, Restated 2018Q4, 2019Q1, and 2019Q2, All-Inclusive Index, Ex Parte No. 290 (Sub-No. 5) (2019-2), Quarterly Rail Cost Adjustment Factor, Surface Transportation Board, March 26, 2019.

Could the proposed structural approach be endogenized in NEMS-CMM using projected indices?

- At the start of each NEMS cycle, EIA could calculate the real rate of change in selected indices relative to the Gross Domestic Product Deflator, apply the base year shares to project the first projection year's escalation rate, and use the share-weighted values for that year to generate shares for application in the next projection year, and so on
- Productivity adjustment would still be necessary based in part on analyst judgment

RCAF Variable	2017 Share	NEMS Long-Term Projections Escalator Basis
Labor	34.8%	Employment Cost Index--Total Private Compensation (2005=1.00)
Fuel	12.9%	Indexed Ultra-Low Sulfur Diesel Fuel Price
Materials & Supplies	4.9%	Wholesale Price Index – Metals and Metal Products (1982=1.00)
Equipment Rentals	5.7%	Wholesale Price Index – Industrial Commodities less Energy (1982=1.00)
Depreciation	15.7%	Wholesale Price Index – Fuel and Power (1982=1.00)
Interest	2.1%	Indexed 10-year U.S. Treasury Bond Rate
Other	23.%	Wholesale Price Index – Industrial Commodities less Energy (1982=1.00)

Plan for implementing a revised coal transportation rate escalation method in the CMM

- EIA staff will be preparing a summary of the proposed approach and seek additional feedback

- EIA will assess any feedback and a decide on whether to use an econometric or a structural approach and how to project and apply productivity trends under either approach

- EIA will incorporate any changes to the CMM into the AEO2020/1 release; the selected method will be tested and revised as appropriate

- Model documentation and assumptions will be updated, accordingly

Key questions on coal transportation rate escalation?

- Is the proposed structural, weighted-average method preferred to the current, econometrics method?

- How should we treat productivity and what assumptions should be made regarding its value and weighting in the projections?

- What rate of real wage escalation should be assumed for coal transportation labor?

Changes to the Coal Market Module: international coal supply curves

Improvements to the international coal supply curve specification planned for AEO2021

- Currently, the CMM specifies fixed supply curves for each non-U.S., coal-producing region exogenously, adjusting each AEO cycle based on analyst judgment
- EIA worked with Hellerworx, Inc. to suggest an improved methodology
  - Hellerworx, Inc., “DOE/EIA International Coal Supply Curve Modeling Study Methodology,” June 30, 2017 (unpublished)
  - Hellerworx, Inc., “DOE/EIA International Coal Supply Curve and Transportation Modeling – Australia Pilot Study, Ocean Freight Forecast & Coal Data Survey Study Methodology and Documentation,” September 8, 2016 (unpublished)
- The proposed approach would specify econometric functions for each non-U.S. coal producing region in the CMM
  - Econometric specifications based on either publicly-available data or data already available to EIA under contract from private vendors to ensure it can be updated over time
  - Supply curves for some regions, such as China, may still be set exogenously depending on each region’s political or economic constraints or its limited coal export volumes

How are international coal supply curves used in the CMM?

- The CMM represents coal supply available for seaborne coal trade between international regions with exogenously-specified export supply curves for steam coal and metallurgical coal types by producing region; each curve may have up to 10 steps, but most only have a few steps
- The CMM international coal distribution submodule (ICDS) satisfies seaborne coal demand from each import demand region that are determined exogenously based on EIA's *International Energy Outlook*
- The coal trade flows in the ICDS currently represent only seaborne trade of coal, and rail or other movements between regions are not modeled, e.g., shipments from Mongolia to China or Russia to Europe are not represented.
- The ICDS includes 5 U.S. and 12 non-U.S. export regions

International Regions
Source: CMM Model Documentation

CMM Label	Export Region
AU	Australia
NW	Canada, Western
NI	Canada, Interior
SF	Southern Africa[1]
PO	Poland
RE	Eurasia[2] (exports to Europe)
RA	Eurasia[2] (exports to Asia)
HI	China
CL	Colombia
IN	Indonesia
VZ	Venezuela
VI	Vietnam

[1]Southern Africa includes South Africa, Mozambique, and Botswana.
[2]Eurasia includes Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Russia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.

How would the coal export supply curves be estimated using the proposed method?

- The approach suggested by Hellerworx would generate supply curves endogenously in the ICDS for key regions based on regional, econometric regression equations representing coal export quantities as a function of price (free on board, FOB) and other independent variables based on availability of data and analysis

- The approach uses two-stage least squares, and worldwide steel production is required as an instrumented variable

- Other data series are needed to estimate and maintain the supply curves, including coal export quantities, coal miner counts, and coal production by country (to compute base-year productivity)

$$Q_{exported} = f\,(Price_{FOB}, MTPA, Wage, ExpCap, Fuel)$$

Where

- *MTPA: productivity in metric tons per miner-year (mtpa, metric tons per annum)*
- *Wage: coal miner wages–annual by country converted to real U.S. dollars*
- *ExpCap: export capacity based on port, rail, and production capacity for the region*
- *Fuel: diesel fuel price – annual average by country/region*

How would the new coal export supply regions be specified?

- The suggested approach would model 15 unique coal export supply curves specified across 8 regions and 2 coal types
- The remaining five regions have small or declining coal exports or other policy considerations that constrain coal exports that will continue to be modeled using exogenous, static coal supply curves
- The Australia region will be divided into two distinct producing and export regions (AQ: Queensland and AN: New South Wales)

International Regions
Regions getting new Formulations

CMM Label	Export Region
AN	*Australia - NSW*
AQ	*Australia - Queensland*
CL	Colombia[3]
IN	Indonesia
NW	Canada - West Coast
RE	Eurasia[2] (exports to Europe)
RA	Eurasia[2] (exports to Asia)
SF	Southern Africa[1]

International Regions
Regions using exogenous P/Q inputs

CMM Label	Export Region
HI	China
NI	Canada - Interior
PO	Poland
VZ	Venezuela[3]
VI	Vietnam

[1]Southern Africa includes South Africa, Mozambique, and Botswana.
[2]Eurasia includes Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Russia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.
[3]Columbia and Venezuela have only thermal curves.

Plan for implementing a revised international coal supply curve specifications in the CMM

- EIA staff will be preparing a summary of the proposed approach and may seek additional feedback

- A test version of the proposed approach will be incorporated into the CMM and tested to evaluate and revise the specifications before using in the AEO

- Any changes to the CMM will be targeted for incorporation into the AEO2021 release

- Model documentation and assumptions will be updated, accordingly

For more information

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Monthly Energy Review | www.eia.gov/mer

Today in Energy | www.eia.gov/todayinenergy

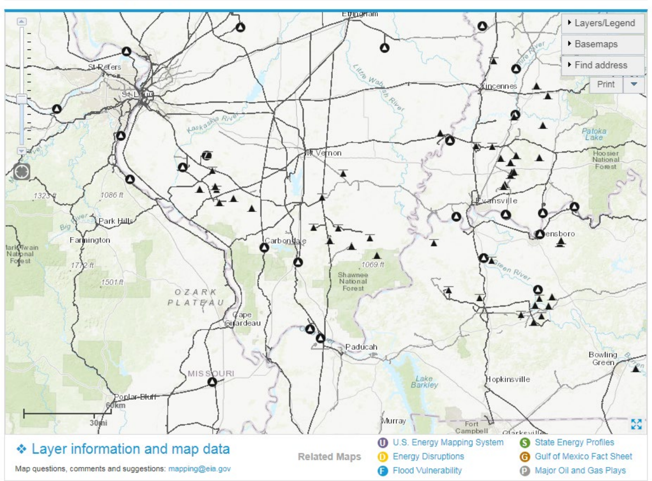
State Energy Profiles | www.eia.gov/state

Coal Data Browser | www.eia.gov/coal/data/browser

U.S. Energy Mapping System | www.eia.gov/state/maps.php?v=Coal (new rail layers)

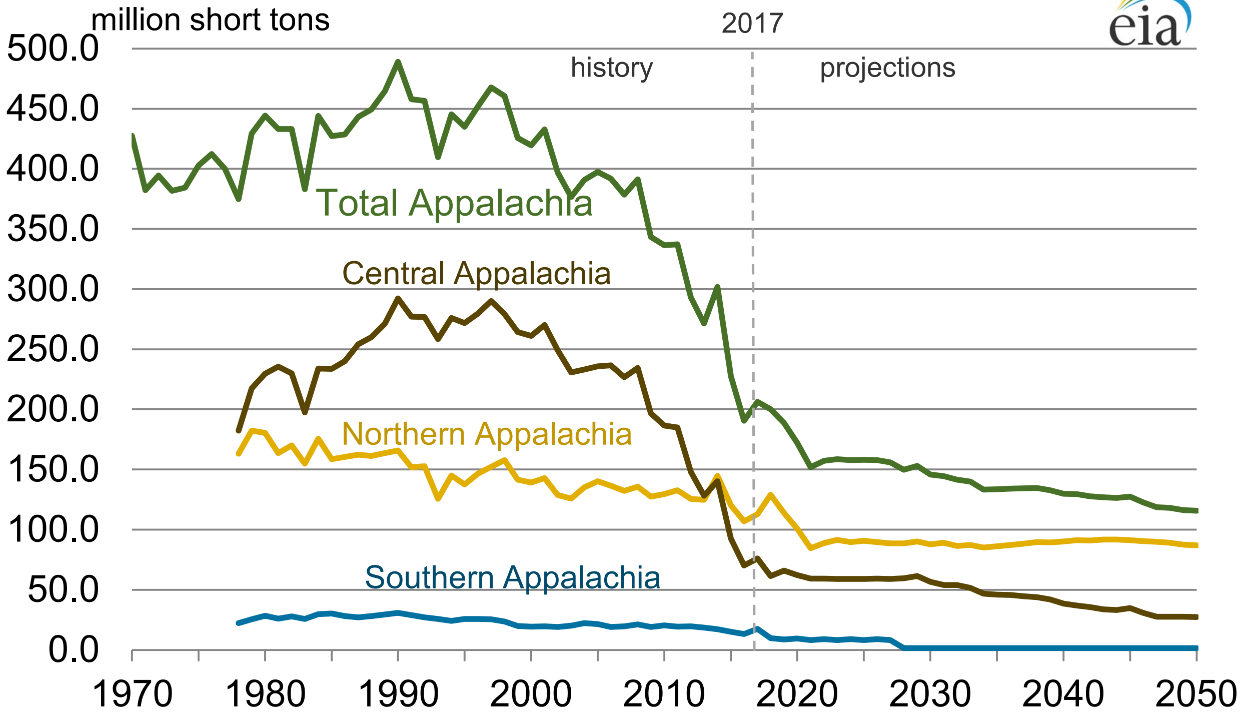
International Energy Portal | www.eia.gov/beta/international/?src=home-b1

U.S. Energy Mapping System



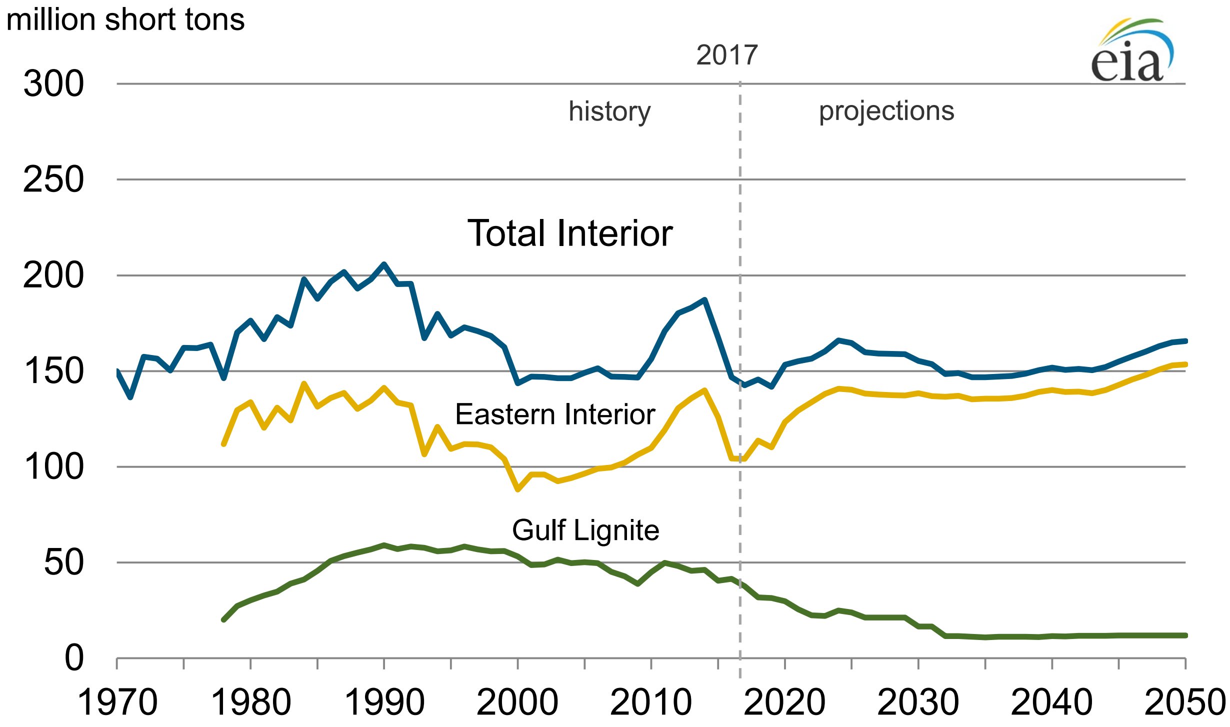
Supplemental slides

Appalachian coal production shows big declines through 2016, with the recent uptick from increased coal exports



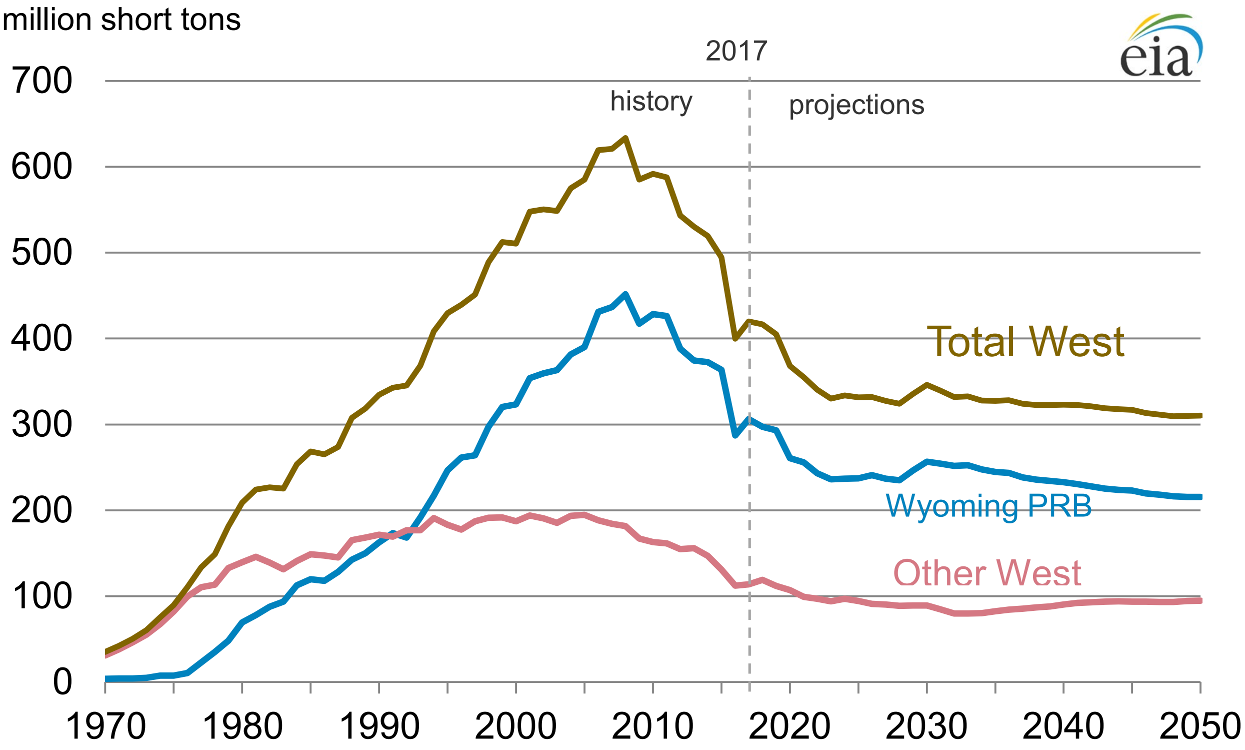
Source: U.S. Energy Information Administration, AEO2019 Reference case (ref2019.d1116a),

Interior coal production declines in 2016 and 2017 but comes back in the Illinois Basin while lignite regions show continued decline



Source: U.S. Energy Information Administration, AEO2019 Reference case (ref2019.d1116a)

Western coal production has seen the greatest rate of decline since 2009



Source: U.S. Energy Information Administration, AEO2019 Reference case (ref2019.d1116a)