BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

PROCEEDING NO. 20P-________G

IN THE MATTER OF GAS PURCHASE PLANS AND GAS PURCHASE REPORTS FOR BLACK HILLS COLORADO GAS, INC. D/B/A BLACK HILLS ENERGY FOR THE GAS PURCHASE YEAR FROM JULY 1, 2020 THROUGH JUNE 30, 2021.

SUBMITTAL FOR DETERMINATION OF COMPLETENESS OF GAS PURCHASE PLAN

Pursuant to Rules 4602(c), 4605 and 4606, Black Hills Colorado Gas, Inc. d/b/a Black Hills Energy ("BHCG"), by its undersigned attorney, submits for determination of completeness BHCG's Gas Purchase Plan ("GPP") for the Gas Purchase Year from July 1, 2020 through June 30, 2021.

Portions of BHCG's GPP contain material that is confidential, proprietary and market-sensitive. As such, they are designated as confidential pursuant to Rule 1100 of the Commission Rules of Practice and Procedure, and BHCG hereby requests confidential treatment of such materials pursuant to the Commission's rules governing confidentiality. A public version is attached in compliance with Rule 4609(a).

Pursuant to Rule 4605(e), BHCG's GPP submittal includes a separate GPP for each GCA rate area.

In addition to undersigned counsel, copies of all notices, pleadings, correspondence, and other documentation regarding this filing should be sent to the following individuals:

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WHEREFORE, BHCG respectfully requests that the Commission deem BHCG's 2020-2021 Gas Purchase Plan complete pursuant to Rule 4605(c).

Respectfully submitted this 1st day of June, 2020.

/s/ *Emanuel T. Cocian*
Emanuel T. Cocian, #36562
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d/b/a Black Hills Energy

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
Gas Purchase Schedule
GPP Attachment No. 1

For the preparation of the GPP, BHCG first conducts a design day study (regression analysis) of past weather and usage conditions. After analyzing historical weather and usage data, a regression equation is used to find a correlation between the actual temperature and actual customer consumption for the past three years. The design day study provides a statistically valid representation of what customer requirements will be on a day in which that temperature level is experienced (the design day). This correlation is then applied to normal monthly average temperatures in Colorado to arrive at the normal monthly customer demand for each month. The customer load growth rate for the last three years is also determined.

Second, BHCG determines the estimated total monthly gas supply requirements by incorporating the volumetric effect of anticipated storage injections and withdrawals (where applicable) into the monthly normalized customer demand.

Third, an analysis is done to determine the ratio of minimum daily customer demand to average daily customer demand for each month. From this analysis, the multi-month gas supply purchase plan volumes are defined. This plan contains monthly targets of firm daily gas purchases that are consistent within each month but do vary from month to month.

Attachment No. 1 is the July 1, 2020 – June 30, 2021 Gas Purchase Schedule providing specific projected gas commodity supplies that BHCG plans to purchase in order to meet projected gas sales demand during each month of the gas purchase year, July 1, 2020 through June 30, 2021. Specifically, this schedule displays data applicable to each of the following:

1. BHCG's forecasted system sales requirements;
2. BHCG's forecasted gas supply sources; and
3. BHCG's forecasted storage gas activity, based on utilization of the storage capacity held by BHCG to facilitate storage activity, where applicable.

Specific information is being filed with a request this information be treated as confidential, proprietary and market-sensitive, is highlighted in yellow and is labeled as:

- Confidential Central GPP Attachment No. 1;
  - Confidential Central GPP Attachment No. 1 (Formerly Arkansas Valley GCA Rate Area);
  - Confidential Central GPP Attachment No. 1 (Formerly BHCOG GCA Rate Area);
- Confidential North/Southwest GPP Attachment No. 1;
  - Confidential North/Southwest GPP Attachment No. 1 (Formerly North Central GCA Rate Area);
  - Confidential North/Southwest GPP Attachment No. 1 (Formerly North Eastern GCA Rate Area);

Black Hills Energy
Ready

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
Gas Purchase Schedule
GPP Attachment No. 1

  - Confidential North/Southwest GPP Attachment No. 1 (Formerly Southwestern GCA Rate Area); and
- Confidential Western Slope GPP Attachment No. 1.

BHCG treats the highlighted information contained in GPP Attachment No. 1 as confidential and requests that the Commission also treat such portions of GPP Attachment No. 1 as confidential. Public versions of these Attachments are also being filed.

BHCG-CO 2020- 2021 GAS PURCHASE PLAN

GPP ATTACHMENT NO. 1

GAS PURCHASE SCHEDULE (PUBLIC VERSIONS)

Central GPP Attachment No. 1

Central GPP Attachment No. 1 (Formerly Arkansas Valley GCA Rate Area)
Central GPP Attachment No. 1 (Formerly BHCOG GCA Rate Area)

North/Southwest GPP Attachment No. 1

North/Southwest GPP Attachment No. 1 (Formerly North Central GCA Rate Area)
North/Southwest GPP Attachment No. 1 (Formerly North Eastern GCA Rate Area)
North/Southwest GPP Attachment No. 1 (Formerly Southwestern GCA Rate Area)

Western Slope GPP Attachment No. 1

Submitted in Compliance with Commission Rule 4606(a)

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
PUBLIC VERSION 2020 - 2021 Gas Purchase Schedule - Central GCA Region
Commission Rule 4606(a)
(Volume in MMBtu)

Sales Requirements	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Total**
Calendar Month Requirements at Customer Meter	[redacted]												
Storage Activity													
Sales Requirements for Customer Demand and Storage													
Statewide FL&U													
CIG FL&U													
Total FL&U													
Total Sales Requirements	[redacted]												

Supply Sources	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Total**
South Receipt Points	[redacted]												
North Receipt Points													
Total Supply Purchases	[redacted]												

Total Portfolio Strategy Budget for the Winter Season of November 2020 - March 2021 (Upcoming Winter Heating Season)

Total Maximum Hedging Volumes for Central GCA Region [redacted]

Total Maximum Hedging Budget - $0.45 average call option premium per MMBtu for Central GCA Region [redacted]

d/b/a Black Hills Energy
PUBLIC VERSION 2020 - 2021 Gas Purchase Schedule - Central GCA Region (formerly Arkansas Valley GCA Rate Area)
Commission Rule 4606(a)
(Volume in MMBtu)

Sales Requirements	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	**Total**
Calendar Month Requrements at Customer Meter	[redacted]												
Storage Activity													
Sales Requirements for Customer Demand and Storage													
Statewide FL&U													
CIG FL&U													
CIG Storage FL&U													
Total Sales Requirements	[redacted]												

Supply Sources	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Total**
South Receipt Points	[redacted]												
North Receipt Points													
Total Supply Purchases	[redacted]												

Total Portfolio Strategy Budget for the Winter Season of November 2020 - March 2021 (Upcoming Winter Heating Season)

Total Maximum Hedging Volumes for Arkansas Valley GCA rate area [redacted]

Total Maximum Hedging Budget - $0.45 average call option premium per MMBtu for Arkansas Valley GCA rate area [redacted]

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
PUBLIC VERSION 2020 - 2021 Gas Purchase Schedule - Central GCA Region (formerly BHCOG GCA Rate Area)
Commission Rule 4606(a)
(Volume in MMBtu)

Sales Requirements	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Total**
Calendar Month Requrements at Customer Meter (Dth)	[redacted]												
Storage Activity	[redacted]												
Sales Requirements for Customer Demand and Storage	[redacted]												
Statewide FL&U	[redacted]												
CIG FL&U	[redacted]												
CIG Storage FL&U	[redacted]												
Total Sales Requirements	[redacted]												

Supply Sources	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Total**
South Receipt Points	[redacted]												
North Receipt Points	[redacted]												
Total Supply Purchases	[redacted]												

Total Portfolio Strategy Budget for the Winter Season of November 2020 - March 2021 (Upcoming Winter Heating Season)

Total Maximum Hedging Volumes for all GCA rate areas [redacted]

Total Maximum Hedging Budget - $0.45 average call option premium per MMBtu for all GCA rate areas (Rounded) [redacted]

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
PUBLIC VERSION 2020 - 2021 Gas Purchase Schedule - North/Southwest GCA Region
Commission Rule 4606(a)
(Volume in MMBtu)

Sales Requirements	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Total
Calendar Month Requirements at Customer Meter Storage Activity Total FL&U	[redacted]												
Total Sales Requirements	[redacted]												

Total Portfolio Strategy Budget for the Winter Season of November 2020 - March 2021 (Upcoming Winter Heating Season)

Total Maximum Hedging Volumes for North/Southwest GCA Region	[redacted]
Total Maximum Hedging Budget - $0.45 average call option premium per MMBtu for North/Southwest GCA Region	[redacted]

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
PUBLIC VERSION 2020 - 2021 Gas Purchase Schedule - North/Southwest GCA Region (formerly North Central GCA Rate Area)
Commission Rule 4606(a)
(Volume in MMBtu)

Sales Requirements	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Total
Calendar Month Requirements at Customer Meter Statewide FL&U PSCo FL&U	[redacted]												
Total Sales Requirements	[redacted]												

Total Portfolio Strategy Budget for the Winter Season of November 2020 - March 2021 (Upcoming Winter Heating Season)

Total Maximum Hedging Volumes for North Central GCA rate area [redacted]

Total Maximum Hedging Budget - $0.45 average call option premium per MMBtu for North Central GCA rate area [redacted]

North/Southwest GPP Attachment No. 1
(Formerly North Eastern GCA Rate Area)
Page 1 of 1

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
PUBLIC VERSION 2020 - 2021 Gas Purchase Schedule - North/Southwest GCA Region (formerly North Eastern GCA Rate Area)
Commission Rule 4606(a)
(Volume in MMBtu)

Sales Requirements	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Total**
Calendar Month Requirements at Customer Meter Storage Activity	[redacted]												
Supply Requirements for Customer Demand and Storage	[redacted]												
Statewide FL&U TIGT Transportation FL&U TIGT Storage FL&U	[redacted]												
Total Sales Requirements	[redacted]												

Total Portfolio Strategy Budget for the Winter Season of November 2020 - March 2021 (Upcoming Winter Heating Season)

Total Maximum Hedging Volumes for North Eastern GCA rate area [redacted]

Total Maximum Hedging Budget - $0.45 average call option premium per MMBtu for North Eastern GCA rate area (Rounded) [redacted]

North/Southwest GPP Attachment No. 1
(Formerly Southwestern GCA Rate Area)
Page 1 of 1

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
PUBLIC VERSION 2020 - 2021 Gas Purchase Schedule - North/Southwest GCA Region (formerly Southwestern GCA Rate Area)
Commission Rule 4606(a)
(Volume in MMBtu)

Sales Requirements	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Total**
Bayfield	[redacted]												
Pagosa Springs													
Total Calendar Month Requirements at Customer Meter	[redacted]												
Statewide FL & U	[redacted]												
PSCo FL & U (Bayfield)													
PSCo FL & U (Pagosa Springs)													
Red Cedar Fuel													
Total Sales Requirements	[redacted]												

Total Portfolio Strategy Budget for the Winter Season of November 2020 - March 2021 (Upcoming Winter Heating Season)

Total Maximum Hedging Volumes for Southwestern GCA rate area [redacted]

Total Maximum Hedging Budget - $0.45 average call option premium per MMBtu for Southwestern GCA rate area [redacted]

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
PUBLIC VERSION 2020 - 2021 Gas Purchase Schedule - Western Slope GCA Region
Commission Rule 4606(a)
(Volume in MMbtu)

Sales Requirements	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Total**
Calendar Month Requrements at Customer Meter	[redacted]												
Statewide Fuel, L & U													
Division Requirement													
RMNG Fuel, L & U													
TransColorado Fuel, L & U													
Northwest Pipeline Fuel, L & U													
Storage Activity													
Total Sales Requirements													

Supply Sources	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-2C**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Total**
On System	[redacted]												
Rifle Plant Inlet													
White River Hub													
Olathe & Roan Cliffs													
Total Supply Purchases	[redacted]												

Total Portfolio Strategy Budget for the Winter Season of November 2020 - March 2021 (Upcoming Winter Heating Season)

Total Maximum Hedging Volumes for Western Slope GCA rate area [redacted]

Total Maximum Hedging Budget - $0.45 average call option premium per MMBtu for Western Slope GCA rate area [redacted]

Black Hills Energy
Ready

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
Gas Purchasing Pricing Description
GPP Attachment No. 2

For the preparation of the GPP, BHCG captures the following forward curves for the four gas cost adjustment "GCA" regions:

1. CIG Rocky Mtns Curve;
2. NGP Midcon Curve;
3. ANR Curve Index;
4. NWPL WY Curve; and
5. El Paso San Juan Curve.

Pricing in the GPP is tied to a first of the month index as there is no futures pricing for daily spot prices. The pricing will change until trading for that specific month expires. The estimated prices included in this GPP are a snapshot in time as of May 18, 2020.

BHCG develops its system supply for purposes of meeting the requirements of consumers across its system.

Attachment No. 2 is the July 1, 2020 – June 30, 2021 Gas Purchasing Pricing Description providing BHCG's specific projected gas commodity supply prices. Specifically, this schedule displays data applicable to each of the following:

1. BHCG's projection of relevant index prices;
2. BHCG's projection of pricing for each gas supply source; and
3. BHCG's projected storage gas average cost, based on storage gas held by BHCG for supply purposes, where applicable.

GPP Attachment No. 2 corresponds with GPP Attachment No. 1, in that BHCG expects purchases to meet projected sales gas demand during each month of the gas purchase year, July 1, 2020 through June 30, 2021.

Specific information is being filed with a request this information be treated as confidential, proprietary and market-sensitive, is highlighted in yellow and is labeled as:

- Confidential Central GPP Attachment No. 2;
  - Confidential Central GPP Attachment No. 2 (Formerly Arkansas Valley GCA Rate Area);
  - Confidential Central GPP Attachment No. 2 (Formerly BHCOG GCA Rate Area);
- Confidential North/Southwest GPP Attachment No. 2;
  - Confidential North/Southwest GPP Attachment No. 2 (Formerly North Central GCA Rate Area);
  - Confidential North/Southwest GPP Attachment No. 2 (Formerly North Eastern GCA Rate Area);

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
Gas Purchasing Pricing Description
GPP Attachment No. 2

  - Confidential North/Southwest GPP Attachment No. 2 (Formerly Southwestern GCA Rate Area); and
- Confidential Western Slope GPP Attachment No. 2.

BHCG treats the highlighted information contained in GPP Attachment No. 2 as confidential and requests that the Commission also treat such portions of GPP Attachment No. 2 as confidential. Public versions of these Attachments are also being filed.

BHCG-CO 2020- 2021 GAS PURCHASE PLAN

GPP ATTACHMENT NO. 2

GAS PURCHASING PRICING DESCRIPTION (PUBLIC VERSIONS)

Central GPP Attachment No. 2

Central GPP Attachment No. 2 (Formerly Arkansas Valley GCA Rate Area)
Central GPP Attachment No. 2 (Formerly BHCOG GCA Rate Area)

North/Southwest GPP Attachment No. 2

North/Southwest GPP Attachment No. 2 (Formerly North Central GCA Rate Area)
North/Southwest GPP Attachment No. 2 (Formerly North Eastern GCA Rate Area)
North/Southwest GPP Attachment No. 2 (Formerly Southwestern GCA Rate Area)

Western Slope GPP Attachment No. 2

Submitted in Compliance with Commission Rule 4606(b)

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
PUBLIC VERSION 2020 - 2021 Gas Purchasing Pricing Description - Central GCA Region
Commission Rule 4606(b)
(Volume in MMBtu)

Supply Prices	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	WACOG
Supply Price per MMBtu	[redacted]												

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
PUBLIC VERSION 2020 - 2021 Gas Purchasing Pricing Description - Central GCA Region (formerly Arkansas Valley GCA Rate Area)
Commission Rule 4606(b)
(Price in $/MMBtu)

Index Values	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Average
NGPL Midcontinent Forward Price Curve CIG Forward Price Curve	[redacted]												

Supply Sources	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**WACOG**
South Receipt Points North Receipt Points	[redacted]												
Source WACOG	[redacted]												

Storage Fields	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**
CIG Storage	[redacted]											
Storage WACOG	[redacted]											

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
PUBLIC VERSION 2020 - 2021 Gas Purchasing Pricing Description - Central GCA Region (formerly BHCOG GCA Rate Area)
Commission Rule 4606(b)
(Price in $/MMBtu)

Index Values	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Average**
ANR Forward Price Curve CIG Forward Price Curve	[redacted]												

Supply Sources	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**WACOG**
South System Pricing	[redacted]												
North/Central System Pricing	[redacted]												

Storage Fields	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**
Storage	[redacted]											
Storage WACOG	[redacted]											

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
PUBLIC VERSION 2020 - 2021 Gas Purchasing Pricing Description - North/Southwest GCA Region
Commission Rule 4606(b)
(Volume in MMBtu)

Supply Prices	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	WACOG
Supply Price per MMBtu	[redacted]												

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
PUBLIC VERSION 2020 - 2021 Gas Purchasing Pricing Description - North/Southwest GCA Region (formerly North Central GCA Rate Area)
Commission Rule 4606(b)
(Volume in MMBtu)

Supply Prices	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	WACOG
CIG Forward Price Curve Local Purchase Premium	[redacted]												
Supply Price per MMBtu	[redacted]												

North/Southwest GPP Attachment No. 2
(Formerly North Eastern GCA Rate Area)
Page 1 of 1

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
PUBLIC VERSION 2020 - 2021 Gas Purchasing Pricing Description - North/Southwest GCA Region (formerly North Eastern GCA Rate Area)
Commission Rule 4606(b)
(Price in $/MMBtu)

Index Values	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	WACOG
CIG - Forward Price Curve Local Purchase Premium	[redacted]												
Supply Price per MMBTU	[redacted]												

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
PUBLIC VERSION 2020 - 2021 Gas Purchasing Pricing Description - North/Southwest GCA Region (formerly Southwestern GCA Rate Area)
Commission Rule 4606(b)
(Volume in MMBtu)

Supply Prices	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	WACOG
Northwest Pipeline Forward Price Curve	[redacted]												
Local Purchase Premium Bayfield													
Monthly & Spot Bayfield													
El Paso San Juan Forward Price Curve	[redacted]												
Local Purchase Premium Pagosa Springs													
Monthly & Spot Pagosa Springs													
Total Monthly & Spot	[redacted]												

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
PUBLIC VERSION 2020 - 2021 Gas Purchasing Pricing Description - Western Slope GCA Region
Commission Rule 4606(b)
(Price in $/MMbtu)

Supply Sources	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**WACOG**
On System	[redacted]												
Rifle Plant Inlet													
White River Hub													
Olathe & Roan Cliffs													
Source WACOG	[redacted]												

Storage Fields	**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**
Wolf Creek Storage	[redacted]											
Storage WACOG	[redacted]											

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
Portfolio Management Plan
GPP Attachment No. 3

Overview

BHCG approaches the process of purchasing gas supply and transportation with three goals in mind. First, BHCG strives to be a reasonably-priced provider of natural gas in all its service territory. Second, BHCG is committed to ensuring a high level of reliability. This means that, for those customers who are paying for firm natural gas service, especially residential and commercial customers who depend on the service to heat their homes and businesses, the gas will always be there. Finally, BHCG employs tools within its portfolio management plan to mitigate price volatility in its supply portfolio in order to maintain a level of cost stability for its customers.

Industry Assessment

For the Industry Assessment (GPP Attachment No. 3 – Appendix A and GPP Attachment No. 3 – Appendix B), BHCG looks at the current and expected future status of the industry. Industry information comes from sources including, but not limited to, any of the many industry conferences, industrial periodicals, discussions with suppliers, producers, pipelines, other Local Distribution Companies ("LDCs") and internal discussions. All this information is compiled and analyzed to generate an assessment of the industry. The assessment is used to project availability and pricing of natural gas, and the availability of pipeline transportation into the future. It is necessary to consider where the industry is going when making purchasing decisions, not just the current state.

Industry Assessment Strategy

While there are too many unknown factors to accurately forecast the way prices will go over the next year, BHCG uses the information gathered in the industry assessment to determine its supply strategy. Based on the Industry Assessment, several factors have been identified regarding supply availability and price volatility. BHCG employs two main strategies as a framework for its supply process: physical supply and financial hedging.

Black Hills Energy Ready

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
Portfolio Management Plan
GPP Attachment No. 3

For physical supply strategy, BHCG would prefer to purchase most of the supply on a short-term (less than a year) basis, which allows for more flexibility. BHCG will purchase a portion of its gas on a term basis (i.e. periods longer than one month) for the upcoming winter. This will help ensure reliability.

The financial hedging strategy focuses on index vs. fixed-price supply purchases. BHCG has determined that a diversified portfolio strategy is the best means to aid in mitigating price volatility.

Design Day Study

A design day study (regression analysis) is an analysis of past weather and usage conditions. The design day study provides a statistically valid representation of what customer requirements will be on a day in which that temperature level is experienced (the design day).

Analyzing historical weather and usage data is part of the design day study. The purpose is to determine a regression equation that explains both a base and a weather-dependent gas usage amount. The base amount is an estimate of the amount of gas that would be used regardless of weather. This amount could represent any number of things, such as water heater usage and other non-temperature related usage. The weather-dependent amount represents heating load, and as the name implies varies based on the weather.

Protection Level

BHCG generally includes a minimum of 30 years of historical HDDs in its regression analysis. As part of the strategies listed above, BHCG has determined that it is necessary to protect for a 67 to 82 HDD design day depending upon the Gas Cost Adjustment ("GCA") area. An 80 HDD design day is a day in which the average temperature - taken as the daily high and low temperatures divided by two - is minus 15 degrees Fahrenheit.

Design Day Requirement

The analysis described above yielded a design day requirement for each of the GCA Areas. This design day requirement represents the amount of capacity that we estimate would be needed to protect for a design day during the 2020/2021 winter heating season. In order to make this number useful for planning purposes, we need to consider growth. The growth rates vary widely across BHCG's service territory. The town and area around Wellington, Colorado has seen growth of approximately 7.4%, the town and area around Castle Rock, Colorado has seen growth of approximately 2.8% while the Arkansas Valley GCA rate area has increased by approximately 1.2% annually. Since this design day study was calculated using data from the 2019/2020 winter heating season (which was based on a recent experienced peak day event), it is necessary to add this growth rate to the estimates for the 2020/2021 winter heating season. It's important to note that, while this number may seem to be exact, it is only an estimate of what might happen on a design day based on the regression analysis.

Pipeline Transportation Services Portfolio

The pipeline transportation services portfolio is developed to meet the requirements of the customers on a design day. Both the level of service and the form of service must be considered.

Level of Service

The level of service is based upon the results of the design day study. While the design day study estimates the customer requirements on a design day, there are situations in which BHCG might want to purchase more or less capacity than the design day study indicates. Since the design day study is an estimate of customer requirements on that day, it is not necessary to purchase the exact amount indicated, although all other things being equal, the design day estimate should be close. Also, the availability of alternative form of service options and the expectation of future capacity availability are considerations that might serve to cause a difference between the design day estimate and actual transportation capacity purchases.

Form of Service

In many cases, pipelines offer more than one kind of transportation service. Generally, there may be a service that offers more flexibility or other benefits than the standard firm service. When looking at the menu of available transportation services, it is necessary to determine which of these services provide the better value or best meets the needs of the customer. For example, interruptible transportation is one possible way to meet a design day requirement that does not necessitate the purchase of significant amounts of capacity all through the year or that will not be needed at all in some years. Of course, when evaluating interruptible service as an alternative to firm capacity, there must be a high likelihood that such transportation service will meet the customer requirements before such an option would be considered.

Physical Supply Portfolio

There are many different supply sources, pricing, and term options available for BHCG's physical supply portfolio. The following discussion describes the principal elements of the supply portfolio.

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Portfolio Management Plan
GPP Attachment No. 3

Requirements

Requirements are forecasted based on normal weather and are shown on GPP Attachment No. 1. Obviously, warmer or colder than normal weather would cause the requirements to differ from those shown on the Attachment. Storage injection and withdrawal are based on a prorated injection/withdrawal of BHCG's total storage capacity.

Supply Sources

There are two main supply sources that BHCG utilizes in its portfolio. Most of the gas that BHCG delivers to its customers is purchased from its suppliers, who deliver the gas into the upstream pipeline systems for transport to BHCG's city gates. BHCG's supply mix is derived primarily from the upstream pipeline systems. These upstream pipeline systems are:

1. Rocky Mountain Natural Gas LLC provides service to much of the Western Slope GCA region. The towns of Nucla and Naturita on the Western Slope are served by Northwest Pipeline and the Whitewater area is supplied by TransColorado Pipeline. BHCG also holds capacity on Colorado Interstate Gas (CIG) upstream of Rocky Mountain Natural Gas LLC.

2. Public Service Company of Colorado provides upstream services to the North/Southwest GCA region. BHCG also purchases supply on the Red Cedar Gathering Company for the North/Southwest GCA region.

3. CIG provides upstream service to the Central GCA region.

4. Tallgrass Interstate Gas Transmission provides upstream service to the North/Southwest GCA region.

The second supply source is to withdraw gas from storage. Storage is available in the Central, Western Slope, and North/Southwest GCA regions. Gas is injected into storage at summer prices and withdrawn from storage in the winter at the weighted average cost of injection purchases. Storage mitigates the need for BHCG to purchase significant quantities of daily gas when colder than normal weather hits, as well as assists in balancing transportation across the upstream pipelines.

Pricing and Term Options

BHCG uses a standard methodology for forecasting prices. There are two tools that are needed for this analysis: the New York Mercantile Exchange (NYMEX) natural gas futures strip, and a basis differential. The formula for forecasting the price for gas on a given pipeline is to take the NYMEX strip price and add the basis differential (which represents the market forecast of the

Black Hills Energy
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Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
Portfolio Management Plan
GPP Attachment No. 3

difference between the strip price and what the pipeline price will be). For example, if the NYMEX price is $4.00 and the basis differential for CIG is -$0.25, the forecasted price would be $3.75.

Both the NYMEX strip and the basis differentials are merely the aggregate forecast of the market as to what prices will be. Further, there are speculators in these markets that can sometimes cause changes in these numbers that seem to defy logic. These numbers can, and usually do, change on a daily basis. Therefore, the information included in this forecast is already outdated. However, GPP Attachment No. 2 represents the best estimate that BHCG could make at the time of the filing of this GPP.

We have not provided ranges for the price forecast because there is no efficient and effective means to forecast such things. The actual purchase prices could vary significantly from the forecast prices listed in GPP Attachment No. 2, depending on weather, the volatility of the market, etc.

There are five main pricing and term options that we will discuss: Term-Fixed, Term-Index, Monthly, Daily and Derivatives. Term-Fixed means that both the term and the price of the purchases are fixed for more than one month. An example of a Term-Fixed purchase would be 5,000 Dth/d for the months of November through March at $4.00. This generally requires the seller to sell and the buyer to buy the contracted amount of gas every day at the agreed upon price. The advantage of this type of supply arrangement is that the supply is locked up, eliminating the risk of it not being available when needed, and the price is predetermined, eliminating the price volatility that occurs in the market. The disadvantage of this type of supply arrangement is that the price does not adjust if market prices fall below the fixed price.

Term-Index means that the term is fixed for more than one month, but the price will reflect what the index for each given month turns out to be. An example would be 5,000 Dth/d for the months of November through March at CIG + $0.02. The seller is required to sell, and the buyer is required to buy the contracted amount of gas every day at the market-driven price. The advantage of this type of supply arrangement is that the supply is locked up, eliminating the risk of it not being available when needed, and the price is index-based, ensuring that prices will be at or near market each month. The disadvantage of this type of supply arrangement is that it does not aid in mitigating price volatility.

Monthly means that the supply is purchased in the spot market for a one-month term. The supply may be priced based on index or a fixed price. However, these two pricing options tend to result in approximately the same rate, as the fixed prices during each month's bid cycle are what is used to develop the index. The advantages of monthly purchasing are that it provides more flexibility to sculpt requirements and make decisions based on price, as well as ensure that prices will be at or near market. The disadvantage of this type of supply is that it does not aid in mitigating price volatility.

Black Hills Energy
Ready

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
Portfolio Management Plan
GPP Attachment No. 3

Daily means that the supply is purchased in the spot market on a day-to-day basis. Again, this supply may be priced based on an index or a fixed price. The advantages of daily purchasing are that it provides the ultimate flexibility by allowing only the amount needed each day to be purchased, as well as providing the most accurate pricing signals. The disadvantage of this type of supply is that it does not aid in mitigating price volatility.

Derivatives are physical/financial tools that can be used to enhance reliability and/or mitigate price volatility.

BHCG's Plan

There are several products available, but BHCG plans to utilize call option purchases as approved in Proceeding No. 19A-0566G through Decision No. C19-1028. As more fully set forth in GPP Attachment No. 1, as well as Confidential GPP Attachment No. 3 – Appendix F, BHCG's strategy for the winter of 2020/2021 anticipates purchasing call options, purchasing supply at index on a seasonal, monthly and daily basis, and utilizing storage. The hedging budget and volumes are provided on each respective Confidential GPP Attachment No. 1. The volumes and timing of transactions are subject to change based on annual discussions with Staff and the OCC.

Changes to Plan

The plan detailed above describes the process through which BHCG makes its supply and transportation purchasing decisions. In order to document such a plan, it is necessary to make forecasts of events that will occur more than one year in the future. While these forecasts represent our best estimates of what to expect in the future, they are by no means guarantees. Therefore, it may be necessary over the course of the year to make changes to this plan as more information becomes available. For this reason, this document should not be viewed as inflexible, but rather as a description of the thought processes and philosophies that guide our decision-making.

Additional Information

Additional information regarding BHCG's hedging strategy is included as part of GPP Attachment No. 3. This additional information includes:

1. Appendix A – Short-Term Energy Outlook (STEO) published by U.S. Energy Information Administration ("EIA") on May 12, 2020;

2. Appendix B – Annual Energy Outlook 2020 with Projections to 2050 published by EIA on January 29, 2020;

Black Hills Energy
Ready

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
Portfolio Management Plan
GPP Attachment No. 3

3. Appendix C – provides corporate procedures applicable to trade execution for the procurement of hedging instruments; *

4. Appendix D – provides existing corporate policies and procedures governing credit risk management and trading activity;

5. Appendix E – provides existing corporate credit policies applicable to the selection of creditworthy trading partners; and

6. Appendix F – provides the 2020 - 2023 Hedging Program approved in Proceeding No. 19A-0566G through Decision No. C19-1028. *

*Certain portions of Appendix C, Appendix D, Appendix E and Appendix F are confidential, proprietary and market-sensitive, and the confidential portions are highlighted in yellow. BHCG treats the highlighted information contained in theses appendices as confidential and requests that the Commission also treat such portions of Appendix C, Appendix D, Appendix E and Appendix F as confidential. A public version of Appendix C, Appendix D, Appendix E and Appendix F is also being filed.

BHCG-CO 2020- 2021 GAS PURCHASE PLAN

GPP ATTACHMENT NO. 3

PORTFOLIO MANAGEMENT PLAN

Information Common to All Four GCA Rate Regions

GPP Attachment No. 3 - Appendix A

GPP Attachment No. 3 - Appendix B

Public Version of GPP Attachment No. 3 - Appendix C

Public Version of GPP Attachment No. 3 - Appendix D

Public Version of GPP Attachment No. 3 - Appendix E

Public Version of GPP Attachment No. 3 - Appendix F

Submitted in Compliance with Commission Rule 4606(c)

Independent Statistics & Analysis
U.S. Energy Information Administration

May 2020

Short-Term Energy Outlook (STEO)

Forecast highlights

Global liquid fuels

- Although all market outlooks are subject to many risks, the May edition of EIA's *Short-Term Energy Outlook* remains subject to heightened levels of uncertainty because the effects on energy markets of mitigation efforts related to the 2019 novel coronavirus disease (COVID-19) are still evolving. Reduced economic activity related to the COVID-19 pandemic has caused significant changes in energy supply and demand patterns. Crude oil prices, in particular, have fallen significantly since the beginning of 2020, largely driven by reduced oil demand because of COVID-19 mitigation efforts. Despite the April agreement between the Organization of the Petroleum Exporting Countries (OPEC) and partner countries (OPEC+) to reduce production levels beyond the end of the STEO forecast period, crude oil prices have remained at some of their lowest levels in more than 20 years. Uncertainties persist across EIA's outlook for other energy sources, including natural gas, electricity, coal, and renewables.

- Brent crude oil prices averaged $18 per barrel (b) in April, a decrease of $13/b from the average in March. EIA forecasts Brent crude oil prices will average $34/b in 2020, down from an average of $64/b in 2019. EIA expects prices will average $23/b during the second quarter of 2020 before increasing to $32/b during the second half of the year. EIA forecasts that Brent prices will rise to an average of $48/b in 2021, $2/b higher than forecast last month, as EIA expects that declining global oil inventories next year will put upward pressure on oil prices.

- EIA estimates global petroleum and liquid fuels consumption averaged 94.1 million barrels per day (b/d) in the first quarter of 2020, a decline of 5.8 million b/d from the same period in 2019. EIA expects global petroleum and liquid fuels demand will average 92.6 million b/d in 2020, a decrease of 8.1 million b/d from last year, before increasing by 7.0 million b/d in 2021. Lower global oil demand growth for 2020 in the May STEO reflects growing evidence of disruptions to global economic activity along with reduced expected travel globally as a result of restrictions related to COVID-19.

- EIA expects that global liquid fuels inventories will grow by an average of 2.6 million b/d in 2020 after falling by 0.2 million b/d in 2019. EIA expects inventory builds will be largest in the first half of 2020, rising at a rate of 6.6 million b/d in the first quarter and increasing to builds of 11.5 million b/d in the second quarter as a result of widespread travel limitations and sharp reductions in economic activity. Firmer demand growth as the global economy begins to recover and slower supply growth will contribute to global oil inventory draws beginning in the third quarter of 2020. EIA expects global liquid fuels inventories will fall by 1.9 million b/d in 2021.

- EIA forecasts significant decreases in U.S. liquid fuels demand during the first half of 2020 as a result of COVID-19 travel restrictions and disruptions to business and economic activity. EIA expects the largest impacts will occur in the second quarter of 2020 before gradually dissipating over the next 18 months. EIA expects U.S. motor gasoline consumption to fall from 8.6 million b/d in the first quarter of 2020 to an average of 7.0 million b/d in the second quarter before gradually increasing to 8.7 million b/d in the second half of the year. U.S. jet fuel consumption will fall from 1.6 million b/d in the first quarter of 2020 to an average of 0.8 million b/d in the second quarter. U.S. distillate fuel oil consumption is forecast to decline by 0.6 million b/d to average 3.3 million b/d during the same period. For all of 2020, EIA forecasts that U.S. motor gasoline consumption will average 8.3 million b/d, a decrease of 11% compared with 2019, while jet fuel and distillate fuel oil consumption will fall by 25% and 10%, respectively, during the same period.

- EIA has revised its current forecast of domestic crude oil production down from the April STEO as a result of lower crude oil prices. EIA forecasts U.S. crude oil production will average 11.7 million b/d in 2020, down 0.5 million b/d from 2019. In 2021, EIA expects U.S. crude oil production to decline further by 0.8 million b/d. If realized, the 2020 production decline would mark the first annual decline since 2016. U.S. crude oil production has not declined for two years in a row since the 17-year period of declines beginning in 1992 and running through 2008. Typically, price changes affect production after about a six-month lag. However, current market conditions will likely reduce this lag as many producers have already announced plans to reduce capital spending and drilling levels.

Natural Gas

- In April, the Henry Hub natural gas spot price averaged $1.73 per million British thermal units (MMBtu). EIA forecasts that natural gas prices will generally rise through the rest of 2020 as U.S. production declines. EIA forecasts that Henry Hub natural gas spot prices will average $2.14/MMBtu in 2020 and then increase in 2021, reaching an annual average of $2.89/MMBtu. EIA expects prices to rise largely because of lower natural gas production compared with 2020.

- EIA expects total consumption of natural gas to average 81.7 billion cubic feet per day (Bcf/d) in 2020, down 3.9% from the 2019 average primarily because of lower industrial sector consumption of natural gas. EIA forecasts industrial natural gas consumption to average 21.3 Bcf/d in 2020, down 7.1% from 2019 as a result of lower expected manufacturing activity. This expected decline is lower than the 0.3% decline forecast in the April STEO because of large downward revisions to the macroeconomic forecast in the May STEO.

- U.S. dry natural gas production set a record in 2019, averaging 92.2 Bcf/d. EIA forecasts dry natural gas production will average 89.8 Bcf/d in 2020, with monthly production falling from an estimated 93.1 Bcf/d in April to 85.4 Bcf/d in December. Natural gas production declines the most in the Appalachian region and Permian region. In the Appalachian region, low natural gas prices are discouraging producers from engaging in natural gas-directed drilling, and in the Permian region, low oil prices reduce associated gas output from oil-directed wells. In 2021, forecast dry natural gas production averages 84.9 Bcf/d, rising in the second half of 2021 in response to higher prices.

- EIA estimates that total U.S. working natural gas in storage ended April at 2.3 trillion cubic feet (Tcf), 20% more than the five-year (2015–19) average. In the forecast, inventories rise by 2.1 Tcf during the April through October injection season to reach almost 4.2 Tcf on October 31, which would be a record level.

- EIA forecasts that U.S. liquefied natural gas exports will average 5.8 Bcf/d in the second quarter of 2020 and 4.8 Bcf/d in the third quarter of 2020. U.S. liquefied natural gas exports are expected to decline through the end of the summer as a result of lower expected global demand for natural gas.

Electricity, coal, renewables, and emissions

- Although some stay-at-home orders are beginning to be relaxed, the effects of social distancing guidelines are likely to continue affecting U.S. electricity consumption during the next few months. EIA expects retail sales of electricity in the commercial sector will fall by 6.5% in 2020 because many businesses have closed and many people are working from home. Similarly, EIA expects industrial retail sales of electricity will fall by 6.5% in 2020 as many factories cut back production. Forecast U.S. sales of electricity to the residential sector fall by 1.3% in 2020 because of lower electricity demand as a result of milder winter and summer weather, which is offset slightly by increased household electricity consumption as much of the population spends relatively more time at home.

- EIA forecasts that total U.S. electric power sector generation will decline by 5% in 2020. Most of the expected decline in electricity supply is reflected in lower fossil fuel generation, especially at coal-fired power plants. EIA expects that coal generation will fall by 25% in 2020. Forecast natural gas generation is relatively flat this year, reflecting favorable fuel costs and the addition of new generating capacity. Renewable energy sources account for the largest portion of new generating capacity in 2020, driving EIA's forecast of 11% growth in renewable generation by the electric power sector. Renewable energy is typically dispatched whenever it is available because of its low operating cost.

- Although EIA expects renewable energy to be the fastest-growing source of electricity generation in 2020, the effects the economic slowdown related to COVID-19 are likely to affect new generating capacity builds during the next few months. EIA expects the electric power sector will add 20.4 gigawatts of new wind capacity and 12.7 gigawatts of utility-scale solar capacity in 2020. However, these forecasts are subject to a high degree of uncertainty, and EIA will continue to monitor reported planned capacity builds.

- EIA forecasts U.S. average coal consumption will decrease by 23% to 453 MMst in 2020. The decrease is primarily driven by a 24% decline in electric power sector consumption and persistently low natural gas prices. In 2021, consumption is expected to increase by 10% to 498 MMst because of stronger natural gas prices and an overall economic recovery that results in rising electricity generation.

- After decreasing by 2.8% in 2019, EIA forecasts that U.S. energy-related carbon dioxide (CO2) emissions will decrease by 11% (572 million metric tons) in 2020. This record decline is the result of restrictions on business and travel activity and slowing economic growth related to COVID-19. CO2 emissions decline from all fossil fuels, particularly coal (23%) and petroleum (11%). In 2021, EIA forecasts that energy-related CO2 emissions will increase by 5% as the economy recovers and stay-at-home orders are lifted. Energy-related CO2 emissions are sensitive to changes in weather, economic growth, energy prices, and fuel mix.

Forecast Assumptions

Because of the heightened uncertainty surrounding this month's STEO, we have included some of the driving assumptions that affected our forecast this month.

Global Liquid Fuels

Global Petroleum and Other Liquid Fuels Consumption

In the May STEO, EIA revised its 2020 global oil consumption forecast to reflect the most up-to-date information available.

Similar to the March and April STEOs, EIA analyzed reductions in oil demand by evaluating three main drivers: lower economic growth, less air travel, and other declines in demand not captured by these two categories, largely related to reductions in travel because of stay-at-home orders. Based on incoming data and updated assessments of lockdowns and stay-at-home orders across dozens of countries globally, EIA has lowered its forecasts for global oil demand in 2020. The precise effect of lockdowns on petroleum consumption remains highly uncertain because the severity and enforcement of the shutdowns vary by country. EIA currently assumes all stay-at-home orders will be eased by the fourth quarter of 2020. EIA is not assuming resurgent outbreaks of COVID-19 that result in the announcement of further lockdowns.

The May STEO's forecast for non-U.S. economic growth is based on forecasts from Oxford Economics, which have been revised down since the April STEO. In 2020, EIA forecasts global oil consumption-weighted gross domestic product (GDP) to decline by 4.1%, compared with a decline of 0.1% in the April STEO. The sharpest declines occur in the second quarter of 2020 when Oxford Economics forecasts that global GDP will decrease 7.1% compared with 2019.

EIA forecasts global liquid fuels consumption will average 92.6 million barrels per day (b/d) in 2020, down 8.1 million b/d from 2019. Following the pattern of the GDP forecast, the sharpest consumption declines are in the second quarter, when EIA forecasts a year-over-year decline in liquid fuels consumption of 18.8 million b/d. EIA forecasts both economic growth and global liquid fuels consumption to increase in 2021. However, any lasting changes to transportation and other oil consumption patterns once COVID-19 mitigation efforts end present considerable uncertainty to the increase in liquid fuels consumption, even if GDP growth increases significantly.

Non-OPEC Petroleum and Other Liquid Fuels Supply

EIA forecasts that the supply of non-OPEC petroleum and other liquid fuels will decline by 2.4 million b/d in 2020, compared with a decline of 0.2 million b/d in the April STEO. The steeper decline largely reflects the newly implemented production cuts from non-OPEC participants in the OPEC+ agreement. EIA expects the largest non-OPEC production declines in 2020 to occur in Russia, the United States, and Canada.

EIA expects production of non-OPEC petroleum and other liquid fuels to increase in 2021. Production in countries that have implemented voluntary production cuts will generally rise in 2021 as global oil demand recovers. However, EIA forecasts production to continue to decline in the United States, where production is driven by price-sensitive shale operators.

EIA expects Russia to experience the largest liquid fuels production declines in 2020 among OPEC+ producers, with forecast declines of more than 0.8 million b/d compared with 2019. EIA expects Russia's liquid fuels production to rise in 2021.

EIA expects total production of liquid fuels in the United States to fall by 0.8 million b/d in 2020, largely as a result of reductions in drilling in price-sensitive tight oil regions. EIA expects U.S. supply to fall by another 0.6 million b/d in 2021.

EIA expects Canada's total liquid fuels production to fall by 0.4 million b/d in 2020. This decrease is a result of 2019 government-ordered production cuts in Alberta and economic shut-ins because of the effect of low oil prices and falling demand for oil exports. In 2021, EIA expects Canada's production to increase and return to near 2019 levels. EIA does not expect any additional production from new upstream projects to come online during the forecast period, only expansions of existing projects.

EIA expects Brazil's production of petroleum and other liquid fuels to grow more slowly than previously forecast. On April 1, Brazil's national oil company, Petroleo Brasileiro, S.A. (Petrobras), deepened its production cuts to 200,000 b/d. EIA expects this level of cuts to continue for the remainder of 2020. Petrobras will idle some shallow-water platforms with higher production costs in the Sergipe, Rio Grande do Norte, and Ceará states to achieve these cuts. In addition, production volumes from the P-70 floating, production, storage, and offloading vessel (FPSO) will be delayed until 2021. The P-70 was originally scheduled to begin producing in the first half of 2020, before it was damaged in a storm in February 2020. Growth in 2021 will be restrained as previously scheduled FPSOs (Carioca, Sepia, Guanabara) are now delayed because of the economic slowdown related to COVID-19 restrictions that are affecting production schedules. In 2020, EIA also expects biofuels to be affected by reduced ethanol demand, and it expects sugar cane millers to switch to sugar production as a result of pricing conditions.

Mexico agreed to 100,000 b/d of cuts under the OPEC+ agreement. EIA had previously forecast crude oil production to decline in Mexico in 2020 and 2021 because of natural declines in mature fields. EIA now expects additional declines as result of Mexico shutting in new priority wells to fulfill the OPEC+ obligation. Overall EIA expects Mexico's annual average liquid fuels production to fall by almost 0.1 million b/d in both 2020 and 2021.

Norway's Ministry of Petroleum and Energy announced unilateral production cuts on the Norwegian continental shelf to help stabilize world oil markets. Norway will limit production of crude oil to no more than 1.609 million b/d in June and no more than 1.725 million b/d for the remainder of 2020. EIA assumes Norway's crude oil production will adhere to these levels.

In Asia, EIA expects India to shut in about 120,000 b/d of production during the next few months as a result of the immediate economic impacts related to COVID-19 on labor mobility and other logistics. In addition, the significantly lower oil price environment will reduce capital expenditure by upstream investors in both China and India and shutter production at higher production cost fields, such as China's tight oil plays in the north central and northwest of the country and the mature fields that require enhanced oil recovery. EIA expects declines to deepen in 2020 and 2021. India plans to begin oil production from the deepwater KG-DWN-98/2 oil and natural gas project in early 2021, which will offset some production declines from mature basins in 2021.

EIA assumes that Malaysia will fully comply with the April 2020 OPEC+ agreement for the months of May and June 2020. Malaysia reports that the production cuts will come from the deepwater Kimanis crude oil grade.

In the non-OPEC Middle East, EIA expects Oman's production to decline in 2020, in contrast to last month's STEO, which forecasted growth. EIA assumes Oman will fully comply with the OPEC+ agreement for May and June 2020. Condensate production will grow slightly through the forecast period from new projects, but crude oil production will remain constrained by lower oil prices and falling investment.

OPEC Petroleum and Other Liquid Fuels Supply

OPEC and partner countries (OPEC+) agreed to new production cuts in early April that will remain in place throughout the STEO forecast period. EIA assumes OPEC countries will mostly adhere to announced cuts during the first two months of the agreement (May and June). This forecast assumes OPEC's production compliance relaxes later in the forecast period, as stated production cuts are reduced and global oil demand begins growing again.

EIA forecasts OPEC crude oil production will fall below 24.1 million b/d in June, a 6.3 million b/d decline from April when OPEC production increased following an inconclusive meeting in March. The forecast for June OPEC production does not account for additional voluntary cuts announced by the Saudi Energy Ministry on May 11. If OPEC production declines to less than 24.1 million b/d, it would be the group's lowest level of production since March 1995.

EIA expects OPEC production will begin increasing in July 2020 in response to rising global oil demand and prices. From that point EIA expects a gradual increase in OPEC crude oil production through the remainder of the forecast, with production rising to an average of 28.5 million b/d during the second half of 2021.

Part of this increase is the result of oil production resuming in Libya. After reaching production levels of 1.2 million b/d in late 2019, Libya's crude oil output averaged 80,000 b/d in April 2020. Most of the country's export ports closed and several oil fields were shut-in, including El Sharara and El Feel, in January 2020. With the ongoing civil war in Libya, EIA does not expect production to increase until late 2020. Once currently shuttered export terminals and oil fields reopen, EIA expects that Libya will boost production to near-capacity despite low oil prices in a relatively short time.

EIA expects that OPEC surplus crude oil production capacity, which averaged 2.5 million b/d in 2019, will average 5.8 million b/d during the third quarter of 2020. EIA expects it to decline to an average of 3.7 million b/d in 2021 with increased production as the targeted cuts are relaxed. These capacity increases include the Neutral Zone production ramp up that started in March 2020 that will add 0.6 million b/d of additional surplus capacity when completed in a year.

OECD Petroleum Inventories

An unprecedented drop in global oil demand in 2020 leads EIA to forecast that global oil inventories will build at an average rate of 2.6 million b/d for the year, the largest annual inventory build during the 40 years that EIA has tracked international data.

Unlike previous periods of significant global oil inventory builds, where oversupplied market conditions persisted for several quarters (for example, 1997–98 and 2014–16), EIA expects that inventory builds in 2020 will be of an unprecedented magnitude but will only occur for two quarters. Forecast builds average 9.1 million b/d during the first half of 2020, peaking at a build of 22.8 million b/d during April. EIA estimates that builds during the first half of 2020 could add 1.6 billion barrels to global inventories, likely leaving global storage near full capacity. EIA expects global liquid fuels inventories to draw at an average rate between 2.5 million b/d and 3.0 million b/d from the third quarter of 2020 through the end of 2021, given the implementation of OPEC+ production cuts beginning in May, economically driven reductions in U.S. oil production, and a return of global oil demand. Draws of this magnitude would largely work off the inventory builds accrued during the first half of 2020.

Crude Oil Prices

Brent crude oil spot prices averaged $18 per barrel (b) in April, down $13/b from March as global oil demand continued to fall and global oil inventories rose strongly. In particular, crude oil prices fell as concerns regarding the capacity of global oil storage to handle expected inventory builds increased. EIA expects that the rate of inventory builds peaked in April, and as oil demand begins to return and oil supply decreases, upward price pressures will begin to emerge. With global oil demand expected to exceed supply beginning in the second half of 2020 and continuing through the forecast period, prices could rise steadily beginning in the second half of this year. Although EIA forecasts significant inventory draws beginning in July, high existing inventory levels, high OPEC spare production capacity, and uncertainty about the trajectory of oil demand will likely limit, but not completely contain, upward crude oil price movements.

EIA expects Brent crude oil prices will rise to an average of $32/b during the second half of 2020 and $48/b on average in 2021, reaching $54/b by the end of the year. However, this price path reflects an expected of global oil consumption to 97.4 million b/d during the second half of 2020, along with relatively high compliance to announced OPEC+ production cuts, both of which are uncertain. Also, the degree to which the U.S. shale industry responds to the current low prices will affect the oil price path in the coming quarters.

U.S. Liquid Fuels

Consumption

EIA assumes significantly lower levels of U.S. liquid fuels consumption during much of 2020 as a result of the disruptions to economic and business activity because of the strict containment measures related to COVID-19 that have dramatically reduced all forms of travel. These impacts are expected to be most pronounced during the second quarter of 2020, when most containment measures and wide-scale reductions in business activity are assumed to be in place. EIA expects these impacts to persist through most of 2020, but in the second half of 2020, EIA expects liquid fuels consumption will gradually increase from second-quarter levels as some business activity resumes and stay-at-home orders gradually ease. EIA expects U.S. total liquid fuels consumption will rise from an average of 15.9 million b/d in the second quarter of 2020 to 18.7 million b/d in the third quarter of 2020 and then to average 19.8 million b/d in 2021, up 8% from 2020, but lower than 2019 levels. EIA forecasts travel disruptions will affect jet fuel consumption the most in percentage terms, with consumption expected to decline by 25% year-over-year for all of 2020 and by more than 50% year-over-year in the second quarter. EIA expects gasoline and distillate fuel consumption will both see consumption fall about 10% compared with 2019 levels.

EIA's current forecast for U.S. annual average hydrocarbon gas liquids (HGL) consumption reflects a steeper decline in 2020 followed by a slower recovery in 2021 compared with the previous forecast. The May STEO expects HGL consumption will decline by 7.4% in 2020 and increase by 5.3% in 2021. The current forecast expects a deeper slowdown in manufacturing that keeps petrochemical feedstock and gasoline blending demand for HGLs lower than 2019 levels in both 2020 and 2021. Ethane consumption begins to rise in the first quarter of 2021 as manufacturing begins to recover and as ethane-fed petrochemical plants increase utilization.

Crude Oil Supply

EIA's model for crude oil production in the Lower 48 states' includes structural parameters that reduce the forecast for rigs and wells when the West Texas Intermediate crude oil price falls below $45/b or the Henry Hub natural gas price falls below $2 per million British thermal units, based on historical trends in each region. In addition to this model-based drop, EIA assumes a further 30% reduction in drilling activity on average in the second quarter of 2020 and a 6% reduction in the third quarter of 2020 as a result of low oil prices related to the unprecedented effects of restrictions as a result of COVID-19; many producers have already announced plans to reduce capital spending and drilling levels.

EIA expects that steepest declines in U.S. crude oil production will be in the second quarter of 2020, with forecast month-over-month declines averaging 0.5 million b/d during those three months. EIA expects production to continue declining, albeit at a slower rate, through March 2021, when production bottoms out at 10.7 million b/d, which would be a 2.1 million b/d decline from the record monthly production reached in November 2019. EIA expects production to rise modestly through the end 2021 in response to rising crude oil prices. EIA forecasts annual average crude oil production to be 11.7 million b/d in 2020 and 10.9 million b/d in 2021, both of which are about 0.1 million b/d lower than forecast in the April STEO.

The decline in U.S. crude oil production in 2020 and 2021, combined with rising U.S. liquid fuels consumption, results in the United States returning to being a net importer of crude oil and petroleum products in the third quarter of 2020 and remaining a net importer in most months through the end of the forecast period.

Product Prices

EIA expects that restrictions related to COVID-19 will drive sharp reductions in crude oil prices and U.S. liquid fuels demand during the second quarter of 2020, which will significantly reduce prices for gasoline and diesel fuel during the same period. EIA forecasts that U.S. average retail prices for regular-grade gasoline will average $1.91 per gallon (gal) and diesel retail prices will average $2.22/gal in the second quarter of 2020.

The gasoline and diesel price declines largely reflect a drop in crude oil prices. Refinery margins, after falling significantly as gasoline and diesel demand fell quickly in March and April, have increased recently as refiners have reduced runs. EIA expects petroleum product prices will rise as crude oil prices rise in the coming quarters. However, EIA generally expects U.S. average gasoline prices to remain lower than $2/gal until March 2021.

Natural Gas

Natural Gas Consumption

EIA expects the most significant effects of COVID-19 related restrictions on natural gas demand to occur in the industrial sector. EIA forecasts that industrial demand for natural gas will decrease by 7% in 2020 compared with 2019. The decline reflects a reduction in economic activity, leading to a declining forecast natural gas-weighted manufacturing index through October 2020. The industrial demand for natural gas forecast is particularly sensitive to macroeconomic conditions, and the size and pace of the forecast economic contraction and the subsequent expected economic recovery significantly affect industrial demand for natural gas.

The May STEO assumes minor shifts in space heating demand in April as more people stayed at home rather than go to work or shop at retail establishments as a result of restrictions related to the COVID-19 pandemic. This shift increases residential natural gas demand for a given temperature level while decreasing commercial natural gas demand. Commercial natural gas demand will decrease further in the near term under the assumption that restaurants and other food establishments, which use more natural gas for cooking food and for hot water heating compared with other segments of the commercial sector, will see a particularly high number of closings.

The May STEO forecast assumes that a combination of lower global natural gas demand as a result of restriction related to the COVID-19 pandemic and an unfavorable liquefied natural gas (LNG) pricing environment will lower U.S. LNG exports, primarily in the third quarter of 2020.

Natural Gas Supply

EIA's model for natural gas production in the Lower 48 states includes structural parameters that reduce the forecast for rigs and wells when the West Texas Intermediate crude oil price falls lower than $45/b or the Henry Hub natural gas price falls lower than $2 per million British thermal units (MMBtu), based on historical trends. In addition to this model-based drop, EIA assumes a further 30% reduction in activity on average in the second quarter of 2020 and a 6% reduction in the third quarter of 2020 to account for the unprecedented effects of travel restrictions related to COVID-19 on the level of drilling activity; many producers have already announced plans to reduce capital spending and drilling levels.

Natural Gas Inventories

EIA's natural gas storage forecast assumes an injection season (March through October) storage build that is slightly higher than average because natural gas consumption is forecast to decline relatively quickly in the second quarter of 2020, while production also declines but at a slower rate. In addition, reductions in economic activity reduce natural-gas fired electricity generation. EIA assumes that end-of-October storage levels in 2020 will be almost 4.2 trillion cubic feet, which would be the largest U.S. natural gas storage inventory on record.

Natural Gas Prices

The May STEO assumes that the Henry Hub spot price will remain low compared with historical levels in the near term as reduced business activity and higher-than-average storage levels entering the summer injection season contribute to keeping prices low. In the third quarter of 2020, slowing natural gas production, combined with increasing industrial demand and higher winter demand for space heating, encourage increases in the natural gas price. EIA expects the Henry Hub spot prices will rise from an average of $2.14/MMBtu in 2020 to an average of $2.89/MMBtu in 2021.

Coal

Coal Supply

Coal production has continued to slow, primarily because of low electric power demand. Some large producers have stipulated that their mines will be shut down or idled for periods ranging from 14 to 30 days, while others have not implied a date to resume normal operations. EIA expects that these decreases in overall production will have a noticeable effect on supply, contributing to a steeper decline than would have occurred had these measures not been put into place.

Coal Consumption

EIA expects coal consumption to decline in 2020 as a result of an overall decline in electricity generation. However, EIA forecasts that coal consumption will rise in 2021 because of a general economic recovery that will increase overall electricity generation and an expected increase in natural gas prices that will cause some coal-fired generation units to become more economic to dispatch. Secondary stocks (at power plants) remain high, and even with decreased production, coal plants do not expect shortfalls in the next few months. EIA projects that industrial consumption will also decline as coal coke demand is slowed by unfavorable market conditions and by significantly decreased raw steel production.

Coal Trade

EIA estimates that U.S. coal exports will decrease through 2020. Atlantic markets, which are the primary outlet for U.S. coal exports, are showing considerably decreased demand because of the global economic slowdown. India, the top destination for U.S. exports, has decreased demand for both steam and coking coals as a result of nationwide lockdowns. Smaller U.S. coal export destinations such as Egypt have cancelled proposed coal projects that would have relied on imported fuel. Japan, a large consumer of U.S. coking coal, idled many blast furnaces in the beginning of the second quarter of 2020. COVID-19 related lockdowns affecting large seaborne market suppliers, including Colombia and Indonesia, have stifled global supply, providing some support to international prices but not enough to overcome the overarching shortfalls in demand.

Coal Prices

EIA estimates the delivered coal price to U.S. electricity generators averaged $2.02 per million British thermal units (MMBtu) in 2019, which was 4 cents/MMBtu lower than in 2018. EIA forecasts that coal prices will decrease in 2020 to $1.99/MMBtu and increase in 2021 to $2.04/MMBtu.

Electricity

The restrictions related to the COVID-19 pandemic and the associated economic effects also create a high level of uncertainty regarding EIA’s short-term outlook for U.S. electricity markets. EIA has developed some initial assumptions about potential effects. As EIA receives new survey data during the coming weeks, future STEO forecasts will incorporate this information.

Electricity Consumption

The current STEO forecast incorporates new macroeconomic projections, which lead to a forecast of declines in retail sales of electricity to the commercial and industrial sectors. Social distancing guidelines are likely to especially affect electricity consumption in the commercial sector where many businesses, such as lodging and food service establishments, will experience reduced activity. In addition, increased numbers of people working from home reduces electricity usage in office buildings. EIA assumes these social distancing effects will magnify the economic impact on commercial electricity consumption during the next three to six months, after which time commercial electricity usage is likely to begin to increase.

As people spend more time in their homes, weather-adjusted electricity consumption by the residential sector is likely to increase in the near term, in contrast to the effects on the commercial and industrial sectors. EIA assumes, in particular, that household usage of electronic equipment such as computers and televisions will increase. Other uses of electricity, such as for cooking and for heating water, may also rise. Household use of air conditioning during the summer months is also likely to be greater than normal as more people stay home during the daytime.

Electricity Generation

Macroeconomic effects on electricity supply are also very uncertain because of rapidly changing economic conditions. The status of component supply chains and the construction workforce are likely to affect the building new generating capacity in the near term in many areas of the country. Most of the generating capacity that had been scheduled to come online in 2020 is fueled by renewable energy sources—including solar and wind—and by natural gas.

To represent these impacts on electricity supply, EIA assumes that some of the generating capacity previously reported to EIA as planned to come online in the next six months will be postponed to sometime beyond the STEO forecast period. Most of these postponements are in solar and wind. As EIA continues to collect updates for project development activities reported on our surveys, we will revise these assumptions in future STEO forecasts.

Electricity Prices

The forecast reduction in overall electricity demand resulting from the economic slowdown, along with lower expected natural gas fuel costs for power generation, drives EIA's expectation that wholesale electricity prices will be lower in 2020 throughout the country. The lower costs of electricity supply will likely not affect retail electricity prices in the near term but may be reflected in lower retail prices in the future as utilities make adjustments to their electric rates during the coming months.

U.S. Economic Assumptions and Energy-Related Carbon Dioxide Emissions

Recent Economic Indicators

The STEO is based on macroeconomic projections by Oxford Economics (for countries other than the United States) and by IHS Markit (for the United States). Given the tremendous uncertainty in both the spread and severity of COVID-19 and in the efforts to stop the spread of the virus, these forecasts are significantly more uncertain than normal.

The April version of the Oxford forecast used in this STEO represents a significant downward revision from the previous month, reflecting a greater understanding of the severity of the virus and the effects of the travel restrictions and stay-at-home orders. Using the Oxford data, EIA assumes that global oil-consumption weighted GDP will contract by 2.8% in the first quarter of 2020 and by 4.5% in the second quarter (quarter-over-quarter growth rates). With the assumption that most lockdowns are lifted sometime during the second quarter, growth returns in the second half of 2020, leading to an overall year-over-year growth rate for oil consumption-weighted GDP in 2020 of -4.1%. The recovery continues in 2021, leading to a 6.7% growth rate.

For the United States, EIA used the April 2, 2020 release of the IHS Markit U.S. Short-Term Macroeconomic model with EIA's energy prices. Since the release of the April STEO, the near-term outlook for GDP has significantly declined as policies to slow the spread of COVID-19 remain in place. U.S. real GDP in the May STEO is forecasted to decline by 7.5% in the second quarter of 2020 (quarter-over-quarter) as compared with a 3.5% decline forecast in the April STEO. Year-over-year, the decline in 2020 for the May STEO is 5.4% as compared to the 2.0% decline forecasted in the April STEO. As in the April STEO, the economy is forecasted to return to growth in the fourth quarter of 2020. Employment does not return to pre-pandemic levels by the end of the STEO forecast period.

Energy-Related Carbon Dioxide Emissions.

After decreasing by 2.8% in 2019, EIA forecasts that U.S. energy-related carbon dioxide (CO2) emissions will decrease by 11% (572 million metric tons) in 2020. This record decline is the result of restrictions on business and travel activity and slowing economic growth related to COVID-19. CO2 emissions decline from all fossil fuels, particularly coal (23%) and petroleum (11%). In 2021, EIA forecasts that energy-related CO2 emissions will increase by 5% as the economy recovers and stay-at-home orders are lifted. Energy-related CO2 emissions are sensitive to changes in weather, economic growth, energy prices, and fuel mix.

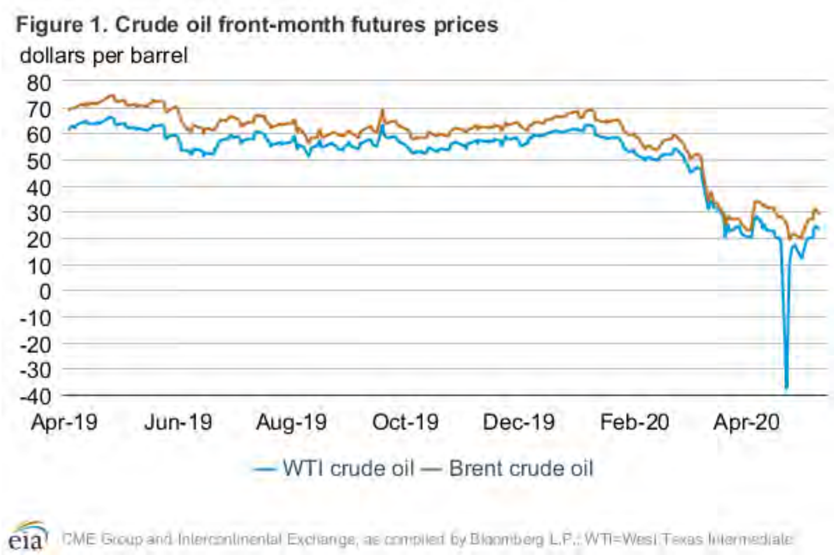
Notable forecast changes

- Because of the rapidly changing situation in energy markets, EIA's forecast includes a significant number of notable forecast changes. Please see the detailed table of forecast changes for more information.

Petroleum and natural gas markets review

Crude oil

Prices: The front-month futures price for Brent crude oil settled at $29.46 per barrel (b) on May 7, 2020, an increase of $4.72/b from April 1, 2020. The front-month futures price for West Texas Intermediate (WTI) crude oil for delivery at Cushing, Oklahoma, increased by $3.24/b during the same period, settling at $23.55/b on May 7 **(Figure 1)**.



The oil futures market continued to exhibit significant volatility in April, marked in particular by the WTI front-month futures price closing at -$37.63/b on April 20, 2020. Although negative pricing has occurred in other commodity markets, it has never occurred in a highly visible and widely traded benchmark crude oil price. For a full explanation of this event, see *This Week in Petroleum*. Since April 21, crude oil prices have steadily increased and could indicate downside price pressure is easing. Many countries have begun to reopen their economies. In addition, the Organization of the Petroleum Exporting Countries (OPEC), along with Russia and a number of other non-OPEC producers (OPEC+), agreed to significant production reductions from May 2020 through April 2022, which should slow the pace of petroleum inventory builds. Although the outlook for global oil markets remains highly uncertain, April 2020 could mark the low-point for oil prices.

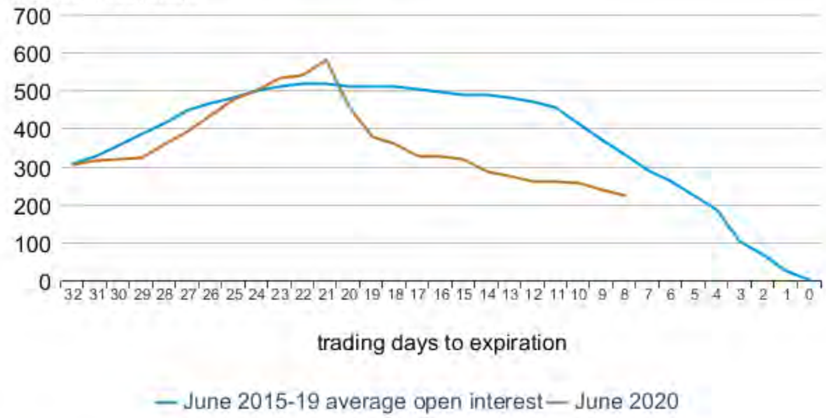
Voluntary production reductions from OPEC+ countries will not be sufficient to prevent significant inventory builds in May and June, however, as EIA expects global demand is forecast to remain subdued, albeit increasing from the lows of March and April. In the May STEO, EIA forecasts global liquid fuels inventories will increase at a pace of 10.1 million barrels per day (b/d) in May and build an additional 1.6 million b/d in June. In the United States, total commercial liquid fuels inventories increased by 2.7 million b/d in April 2020, which would be the largest build for any month since 1959 if confirmed in EIA's *Petroleum Supply Monthly*. Although petroleum inventory data outside the United States is unavailable in real-time, EIA estimates a combination of on-land commercial storage, floating storage, and government strategic stocks will have to be used to accommodate the significant stock builds through June 2020.

EIA forecasts inventories to begin drawing in July 2020, with draws continuing through the end of 2021. A combination of increased demand, declines in production from non-OPEC countries, and continued production restraint from OPEC and partner countries contribute to an average draw of 2.5 million b/d from July 2020 through December 2021. EIA expects continued inventory withdrawals will provide upward price pressure on crude oil prices, although the very high stock level will prevent oil prices from returning to $60/b throughout 2021. In the May STEO, EIA has increased its Brent crude oil price forecast from an average of $46/b in 2021 in last month's STEO to $48/b, largely as a result of the production agreement from OPEC and partner countries and the resulting inventory withdrawals. EIA forecasts Brent crude oil prices to average $34/b in 2020, $1/b higher than the April STEO forecast.

WTI open interest: Price volatility in WTI futures in recent weeks has likely been exacerbated by factors specific to the financial markets. As referenced in EIA's *This Week in Petroleum*, market participants trading the May 2020 WTI contract ahead of expiration paid sellers to avoid taking physical delivery in Cushing, Oklahoma, and settle the contract financially. After the front-month contract rolled to WTI for June 2020 delivery, several market participants that use WTI futures for financial exposure to the crude oil market made public announcements that they would close their positions in the June contract earlier than normal. As a result, open interest (the number of outstanding contracts yet to be settled financially or through physical delivery) in the June WTI futures contract has decreased to levels lower than normal.

For example, the United States Oil Fund (USOF) is the largest crude oil exchange-traded fund (ETF) by total assets. Although the ETF typically holds about 5%–10% of the front-month WTI futures contract's open interest, its holdings increased to about 20% of the open interest by early April. To avoid similar price volatility ahead of the June contract's expiration on May 19, 2020, both USOF and several other funds that hold WTI front-month futures contracts in financial products announced they would be exiting positions in the June contract and rolling to other delivery months. As a result, open interest in the June 2020 WTI futures contract has declined significantly **(Figure 2)**. The five-year (2015–19) pattern for the June WTI contract tends to see open interest remain at about 500,000 contracts until about 12–14 trading days left to expiration, when market participants begin closing positions to avoid settlement for physical delivery. In contrast, the June 2020 contract declined to 221,819 contracts as of May 7, 2020, eight trading days before expiration.

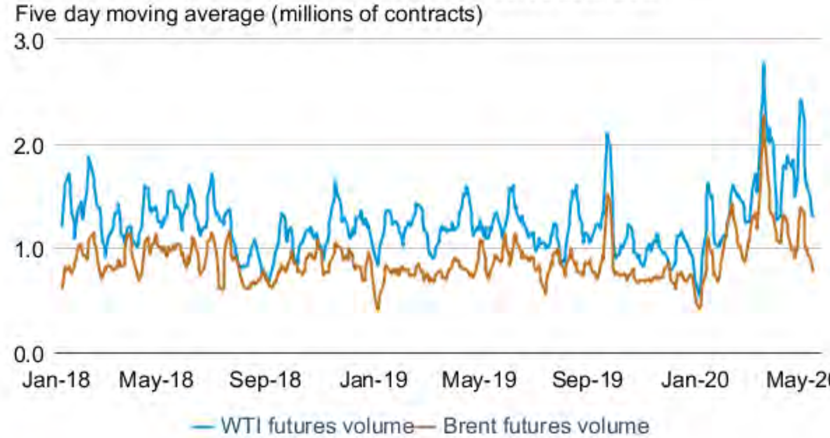
Figure 2. Open interest in June WTI futures contracts



U.S. Energy Information Administration, CME Group, as compiled by Bloomberg L.P.

Crude oil trading volume and open interest: Trading volume for both Brent and WTI crude oil futures reached all-time high levels in March and have remained at elevated levels through the first week of May. The five-day moving average trading volume for all Brent and WTI futures contracts was 0.8 million and 1.3 million contracts, respectively, as of May 7, 2020 **(Figure 3)**.

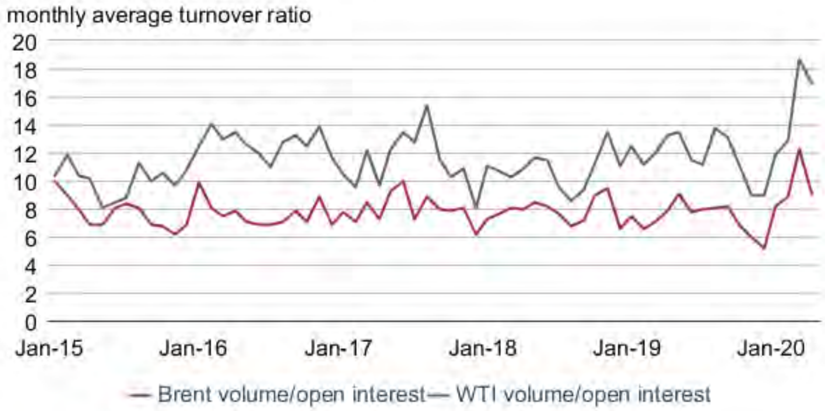
Figure 3. Trading volume for WTI and Brent futures contracts



CME Group and Intercontinental Exchange, as compiled by Bloomberg L.P.; WTI=West Texas Intermediate

One way to identify trading activity and liquidity is the turnover ratio, which measures the average number of times a futures contract trades each day. This value is calculated by dividing a given future contract's total monthly trading volume by its average daily open interest. In March and April, the turnover ratio for all WTI futures contracts increased to record high levels of 19 and 17 per day, respectively. The turnover ratio for Brent futures was lower than that for WTI and did not reach an all-time high, but it increased to the highest level since 2011 in March 2020, averaging 12 per day **(Figure 4)**. Trading activity typically increases when price volatility increases.

Figure 4. Crude oil futures total monthly volume divided by average monthly open interest

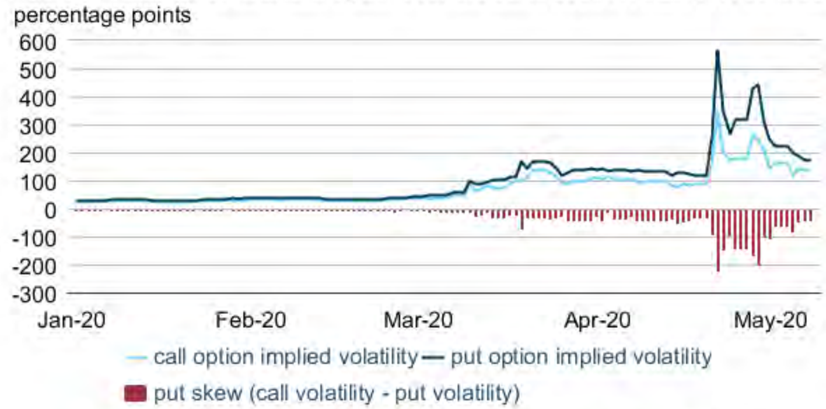


CME Group and Intercontinental Exchange, as compiled by Bloomberg L.P.; WTI=West Texas Intermediate

Financial option volatility: The prices of financial options on WTI futures contracts deviated significantly from their usual patterns throughout much of March and April. The value of NYMEX WTI call options and put options (which give the option holder the right to buy or sell, respectively, a WTI futures contract at a given price within a set timeframe) increases when oil price volatility rises and decreases when price volatility falls. Although, theoretically, with the same strike price and expiration date, the implied volatility of WTI call options should be equal to the implied volatility of WTI put options, the latter almost always exceeds the former. The difference between call and put option volatility (known as the put skew) of front-month WTI futures averaged -2.3 percentage points between 2004 and 2019—a persistence generally attributed to the tendency of market participants to be loss-adverse or to relatively prefer preventing losses over making larger gains.

The skew has grown significantly wider during the past several months **(Figure 5)**. Although the implied volatility of WTI as derived from both call options and put options increased during March and April, call option volatility grew less than put option volatility, leading the put skew for the June 2020 WTI contract to fall to less than -220 percentage points on April 21. This level was the lowest put skew for the front-month WTI futures since at least 2004, the earliest year for which data are available. Much of the overall increase in volatility can be attributed to the particular circumstances surrounding the May 2020 WTI futures contract, and the reaction of market participants to negative crude oil prices—which many had believed were incapable of falling below zero. The disproportionate increase in the level of volatility implied by put options, however, suggests very high demand for protection against further downside price movements, but it also reflects the high premiums that sellers of put options require to take on this risk.

Figure 5. Volatility of financial options for the June 2020 NYMEX WTI contract



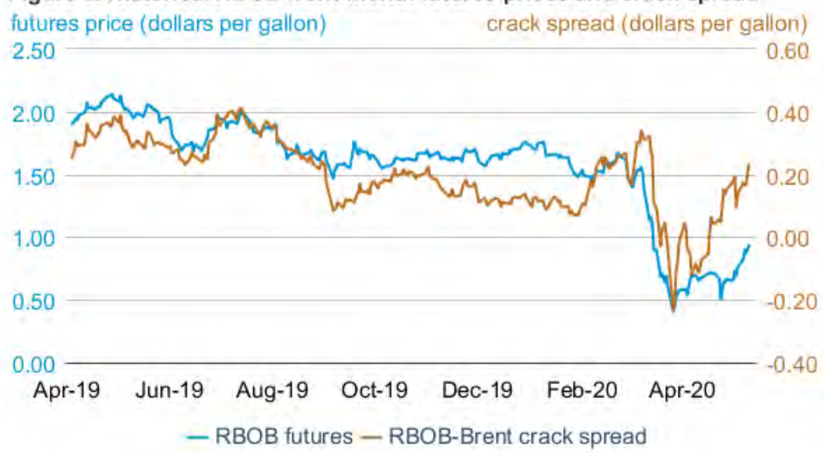
Note: Implied volatilities calculated using standard Black-Scholes assumptions (DFLT) on 25 delta calls and 25 delta puts as listed on Bloomberg.

U.S. Energy Information Administration, CME Group, as compiled by Bloomberg L.P.

Petroleum products

Gasoline prices: The front-month futures price of reformulated blendstock for oxygenate blending (RBOB, the petroleum component of gasoline used in many parts of the country) settled at 93 cents per gallon (gal) on May 7, up 38 cents/gal from April 1, 2020 **(Figure 6)**. The RBOB–Brent crack spread (the difference between the price of RBOB and the price of Brent crude oil) increased by 27 cents/gal to settle at 23 cents/gal during the same period. After briefly declining to negative values in late March and again in early April, the RBOB-Brent crack spread increased in the middle of April and continued to rise for the rest of the month.

Figure 6. Historical RBOB front-month futures prices and crack spread

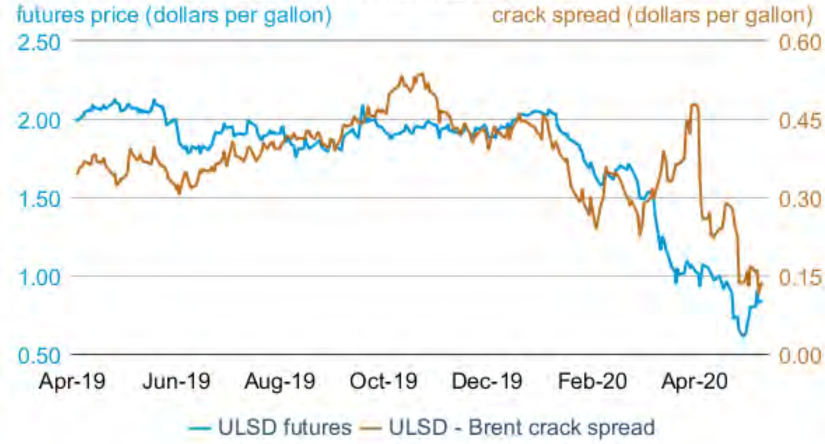


Source: CME Group, as compiled by Bloomberg L.P. Note: RBOB=reformulated blendstock for oxygenate blending

Finished motor gasoline consumption (measured by product supplied) grew to 6.7 million b/d for the week ending May 1, up from 5.1 million b/d on April 3, which contributed to the increases in RBOB front-month futures prices and the RBOB-Brent crack spread. Even with this trend, April's finished motor gasoline consumption of 5.6 million b/d remains 40% below the 9.4 million b/d in April 2019. Personal travel numbers matched the trend of motor gasoline consumption. According to INRIX, compared with the week ending February 29, weekly personal travel was down 47% on April 3 and was down by 36% as of May 1. This lower overall consumption led to gasoline inventories reaching record levels, peaking at 263 million barrels for the week ending April 17.

Ultra-low sulfur diesel prices: The front-month futures price for ultra-low sulfur diesel (ULSD) delivered in New York Harbor settled at 84 cents/gal on May 7, 2020, down 10 cents/gal from April 1, 2020 **(Figure 7)**. The ULSD–Brent crack spread (the difference between the price of ULSD and the price of Brent crude oil) decreased by 21 cents/gal to settle at 14 cents/gal during the same period. The ULSD-Brent crack spread ended March at the highest level for that month in five years, but it declined significantly the first week of April through the end of the month.

Figure 7. Historical ULSD front-month futures price and crack spread

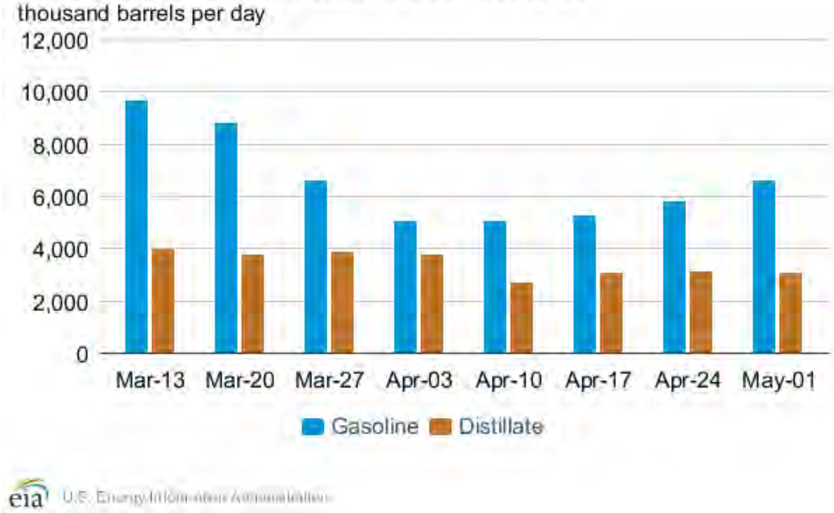


Source: CME Group, as compiled by Bloomberg L.P. Note: ULSD=ultra-low sulfur diesel

The ULSD-Brent crack spread declined as distillate consumption decreased. Although real-time data remain limited, EIA estimates that April 2020 distillate consumption was 3.0 million b/d, a decrease of 0.9 million b/d (23%) from April 2019. If confirmed in EIA's *Petroleum Supply Monthly*, this level will be the lowest monthly consumption level for the month of April since 1993. A possible explanation for the drop in consumption is less long-haul truck travel. For example, according to INRIX's data, for the week ending February 29 trucking was down 9% the week ending April 24. Even though distillate consumption has recently decreased, refiners have shifted more of their efforts toward refining distillate, likely because diesel demand initially decreased less than that for other fuels such as gasoline and jet fuel. The more delayed drop in distillate consumption initially supported distillate refining margins and encouraged refineries to increase distillate production. EIA estimates the refinery distillate yield increased to 39%, compared with 30% in April 2019, and refinery gasoline yield decreased to 40%, compared with 45% a year ago. As a result of the downward shift in demand and increased distillate yield, ending stocks of distillate increased throughout the month, ending the month with 23 million more barrels (18%) than at the same time last year.

Gasoline and distillate consumption: When the United States proclaimed a national state of emergency on March 13, gasoline and distillate demand responded differently. From March 13 to April 3, gasoline consumption dropped 48%, from 9.7 million b/d to 5.1 million b/d **(Figure 8)**. In that same time frame, distillate consumption dropped 5%, from 4.0 million b/d to 3.8 million b/d. The next week, from April 3 to April 10, distillate declined 1.1 million b/d (28%), while gasoline increased slightly. From April 10 to May 1, distillate consumption increased by 0.4 million b/d (13%) and gasoline consumption increased by 1.6 million b/d (31%).

Figure 8. U.S. gasoline and distillate product supplied

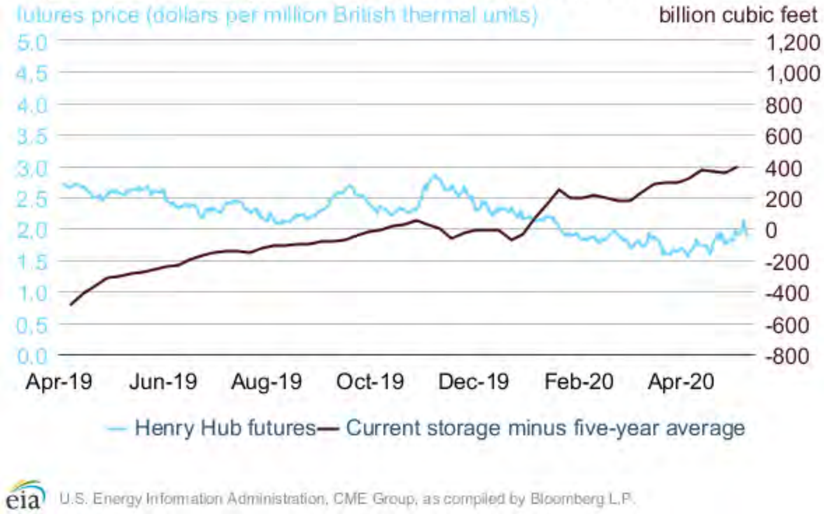


The lag between the decreases in demand can likely be attributed to the difference in how restrictions to limit the spread of COVID-19 affect the uses of the two fuels. Gasoline consumption depends heavily on personal travel such as commuting to work or to social gatherings that were generally suspended by restrictions. As a result, gasoline consumption decreased immediately. Distillate consumption depends more on freight movements and likely was more affected by slowing economic growth than the restrictions themselves. Distillate is also used in activities that are less directly affected by restrictions, such as the diesel engines of heavy construction equipment and as heating oil both for heating buildings and for industrial heating. The restrictions may have indirectly affected these uses over time by means of reduced economic activity that eventually led to a decrease in consumer spending for all goods. Diesel fuel is also used in oil and natural gas drilling operations, which have decreased significantly.

Natural Gas

Prices: The front-month natural gas futures contract for June delivery at the Henry Hub settled at $1.89 per million British thermal units (MMBtu) on May 7, up 31 cents/MMBtu from April 1, 2020 **(Figure 9)**.

Figure 9. U.S. natural gas front-month futures prices and storage



Futures price spreads: The natural gas 1st-13th price spread settled at -$0.67/MMBtu on May 7, continuing a period of contango (when near-term prices are lower than longer dated ones) which began in November 2019 **(Figure 10)**. In periods of contango, there is an incentive for market participants to store natural gas and sell it later at the higher priced future month contract. The 1st-13th spread has been in contango since late 2019 because of three major factors. First, mild winter weather contributed to higher inventories relative to the five-year average. Second, reduced demand for natural gas in the power and industrial sectors related to mitigation efforts related to COVID-19 has contributed to lower front-month prices relative to 13th-month prices. Finally, EIA expects U.S. production of dry natural gas to fall by more than consumption over the next year, placing upward pressure on future prices. EIA forecasts a decline of 0.2 Bcf/d and 4.9 Bcf/d in consumption and dry gas production, respectively, between June 2020 (the current front-month futures price) and June 2021 (the current 13th-month). Inventories are forecast to decline by 331 billion cubic feet (Bcf) between the same two months.

Figure 10. Natural gas 1st-13th futures price spread

International natural gas prices: Similar to Henry Hub, major international front-month futures benchmarks in Europe (UK National Balancing Point, or NBP; Dutch Title Transfer Facility, or TTF) and Asia (Japan-Korea LNG, or JKM) experienced a significant decline in prices, with spreads between benchmarks also narrowing considerably because of a mild winter as well as the widespread international policy response related to COVID-19 **(Figure 11)**. Notably, TTF and NBP prices traded lower than the corresponding Henry Hub contract. The lack of opportunities for arbitrage stemming from lower spreads between international prices has important implications for the international trade of natural gas and liquefied natural gas (LNG). EIA forecasts in the May STEO that U.S. LNG exports will average 6.0 Bcf/d in 2020 and 7.3 Bcf/d in 2021. Although these levels still represent year-over-year increases, the rate of growth in exports is expected to decline from 67.9% year-over-year in 2019 to 21.1% in 2020 and 21.2% in 2021.

Figure 11. International natural gas prices

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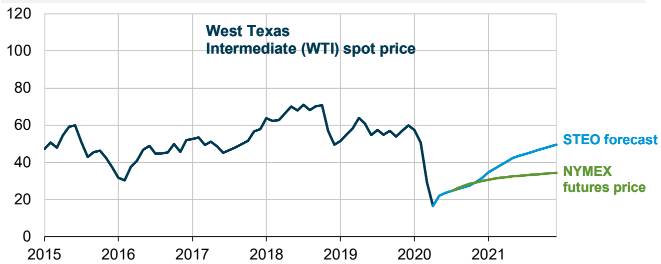
Short-Term Energy Outlook

Chart Gallery for May 2020

EIA is unable to construct NYMEX confidence intervals in this STEO, because of data issues. EIA will update this figure if the data become available.

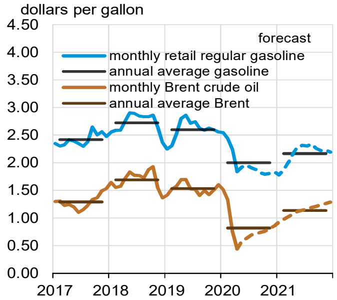


Note: Confidence interval derived from options market information for the five trading days ending May 7, 2020. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Sources: Short-Term Energy Outlook, May 2020, and CME Group

U.S. gasoline and crude oil prices

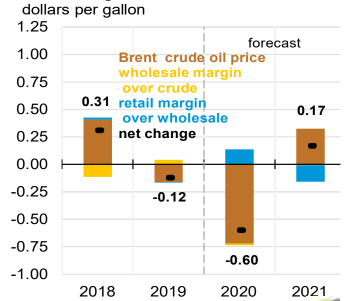
dollars per gallon



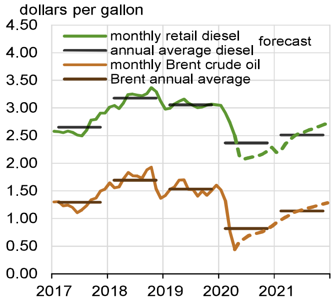
Source: Short-Term Energy Outlook, May 2020

Components of annual gasoline price changes

dollars per gallon

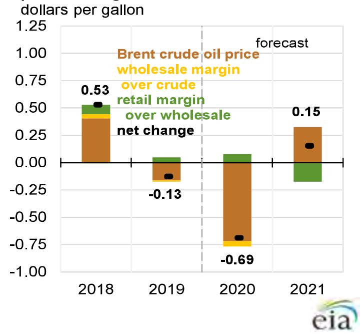


U.S. diesel and crude oil prices

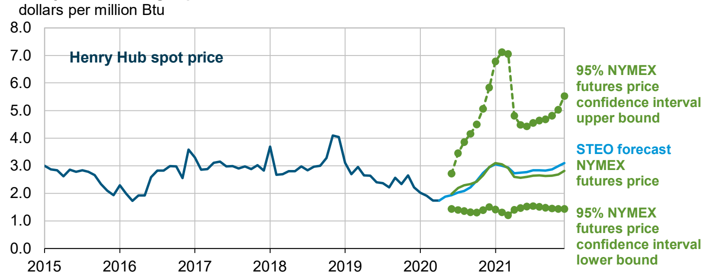


Source: Short-Term Energy Outlook, May 2020

Components of annual diesel prices changes



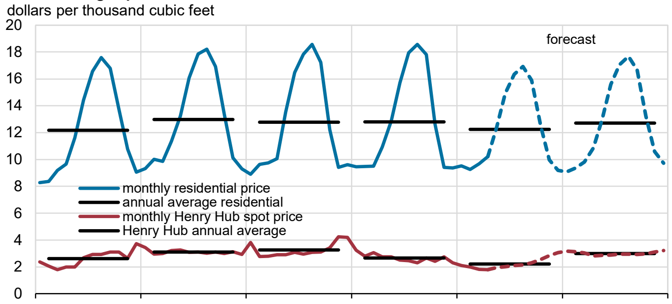
Henry Hub natural gas price and NYMEX confidence intervals



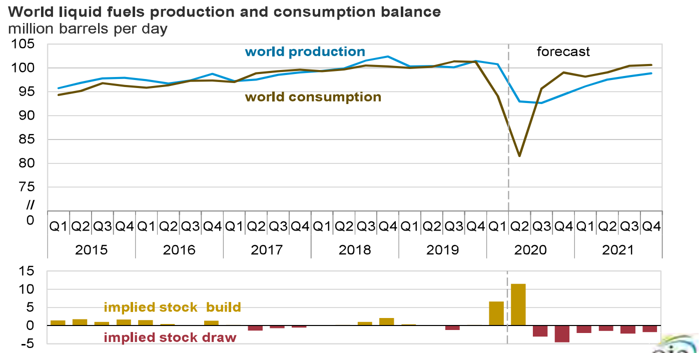
Note: Confidence interval derived from options market information for the five trading days ending May 7, 2020. Intervals not calculated for months with sparse trading in near-the-money options contracts.

Sources: Short-Term Energy Outlook, May 2020, and CME Group

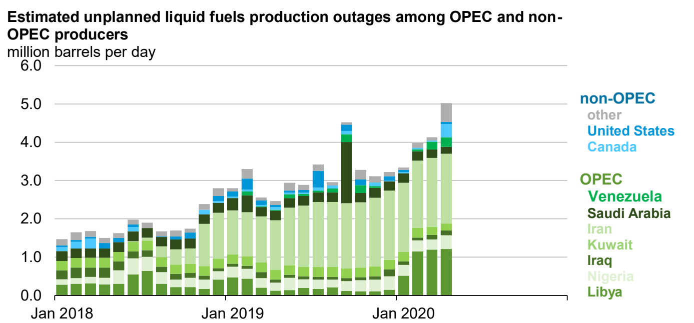
U.S. natural gas prices



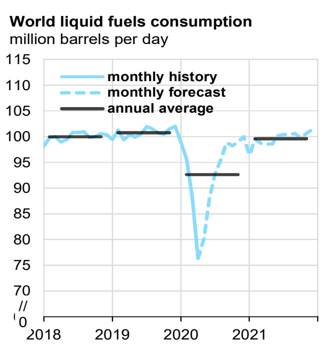
Sources: Short-Term Energy Outlook, May 2020, and Refinitiv

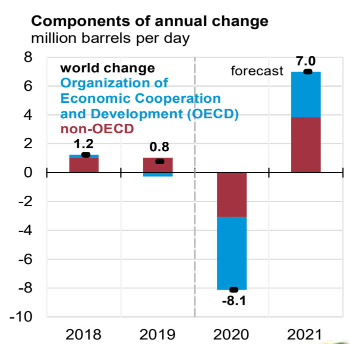


Source: Short-Term Energy Outlook, May 2020



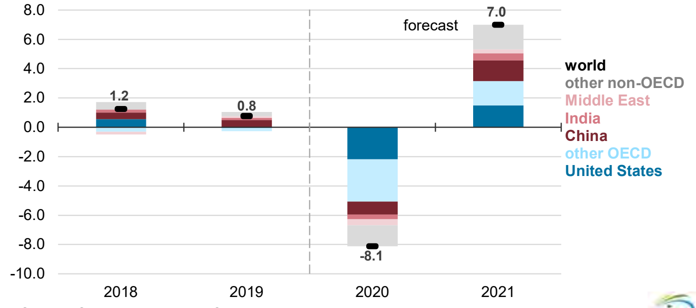
Source: Short-Term Energy Outlook, May 2020





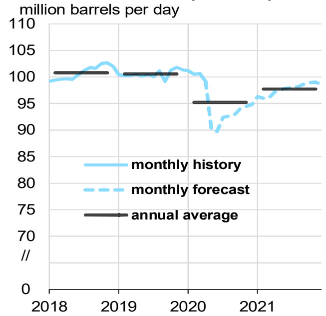
Source: Short-Term Energy Outlook, May 2020

Annual change in world liquid fuels consumption
million barrels per day

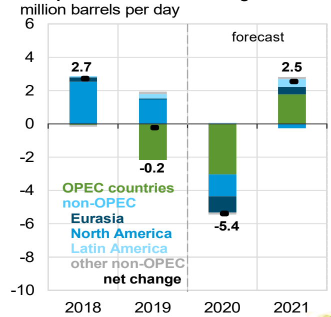


Source: Short-Term Energy Outlook, May 2020

World crude oil and liquid fuels production
million barrels per day

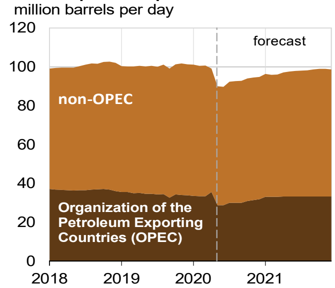


Components of annual change
million barrels per day

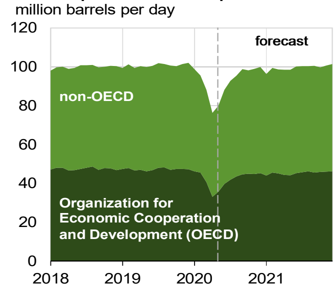


Source: Short-Term Energy Outlook, May 2020

World liquid fuels production
million barrels per day

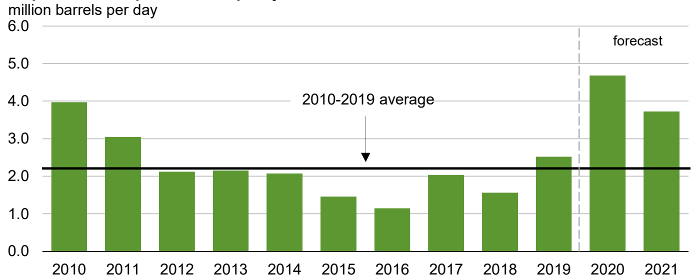


World liquid fuels consumption
million barrels per day



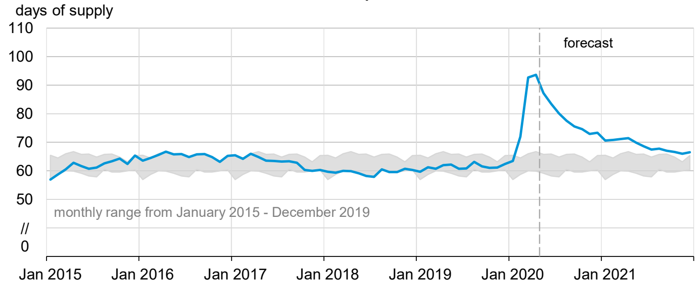
Source: Short-Term Energy Outlook, May 2020

Organization of the Petroleum Exporting Countries (OPEC) surplus crude oil production capacity
million barrels per day



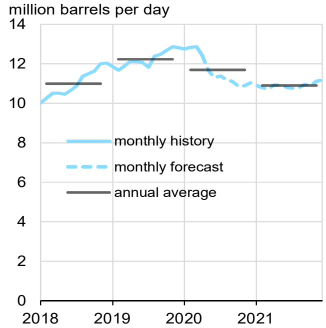
Note: Black line represents 2010-2019 average (2.2 million barrels per day).
Source: Short-Term Energy Outlook, May 2020

Organization for Economic Cooperation and Development (OECD) commercial inventories of crude oil and other liquids
days of supply



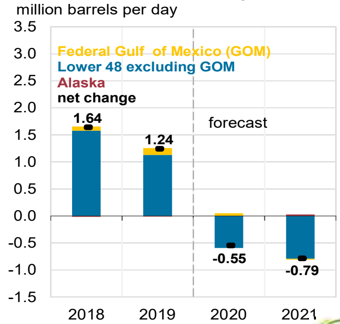
Source: Short-Term Energy Outlook, May 2020

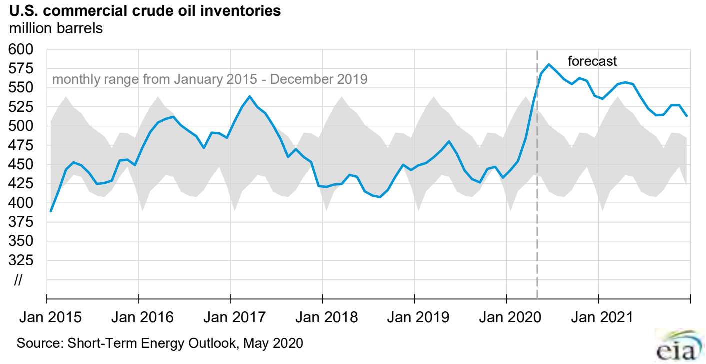
U.S. crude oil production
million barrels per day

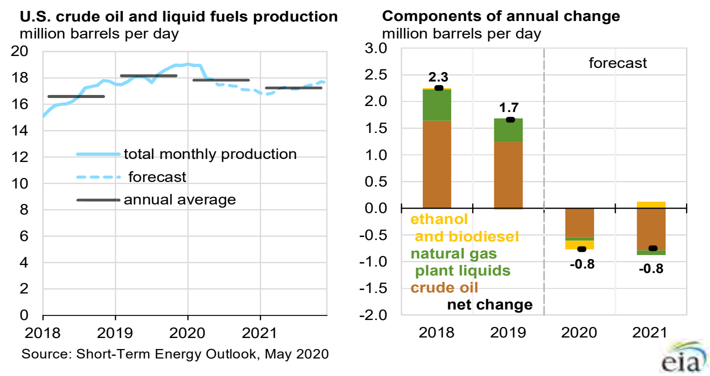


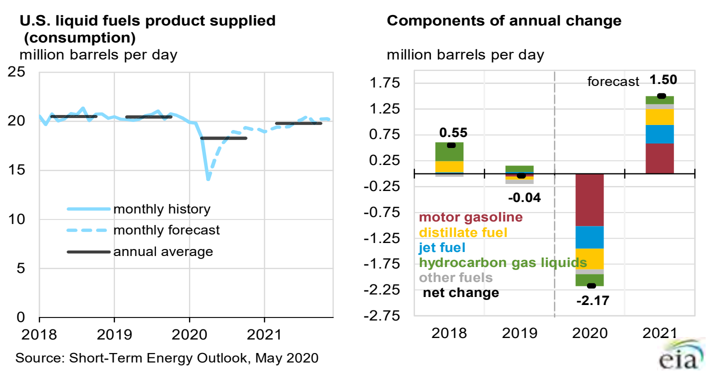
Source: Short-Term Energy Outlook, May 2020

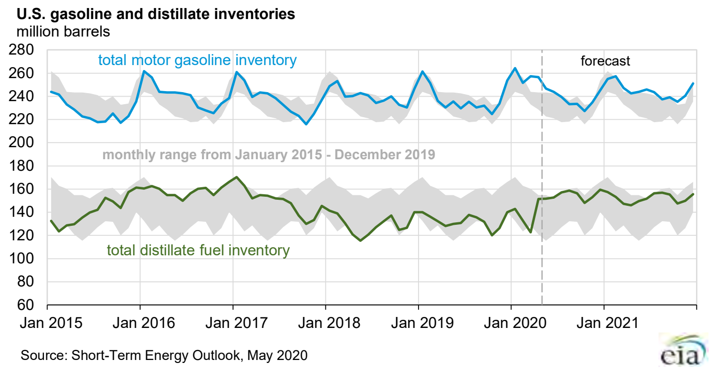
Components of annual change
million barrels per day

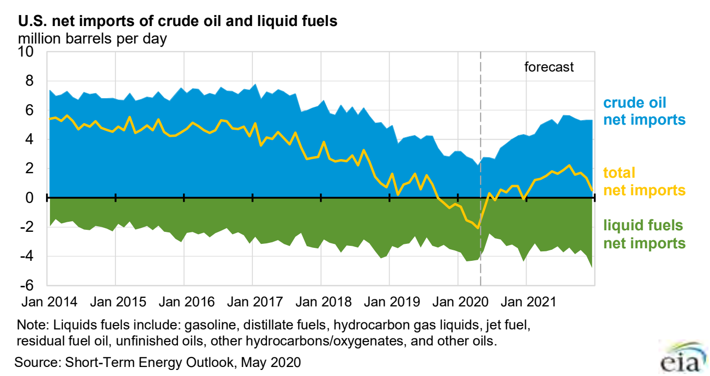


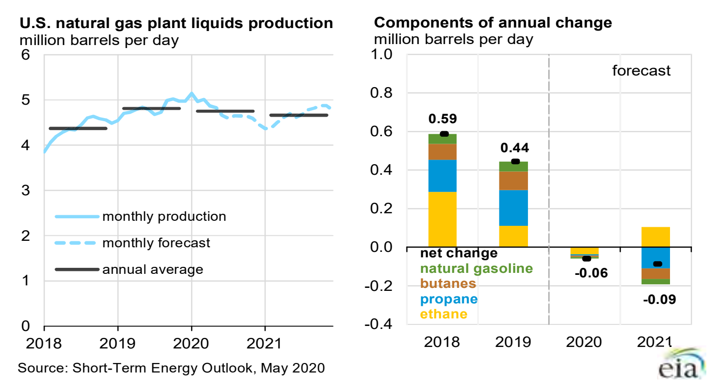

U.S. commercial crude oil inventories
million barrels
600
575
550
525
500
475
450
425
400
375
350
325
//
forecast
monthly range from January 2015 - December 2019
Jan 2015
Jan 2016
Jan 2017
Jan 2018
Jan 2019
Jan 2020
Jan 2021
Source: Short-Term Energy Outlook, May 2020
eia


U.S. crude oil and liquid fuels production
million barrels per day
total monthly production
forecast
annual average
2018
2019
2020
2021
Source: Short-Term Energy Outlook, May 2020
Components of annual change
million barrels per day
forecast
2.3
1.7
-0.8
-0.8
ethanol
and biodiesel
natural gas
plant liquids
crude oil
net change
eia

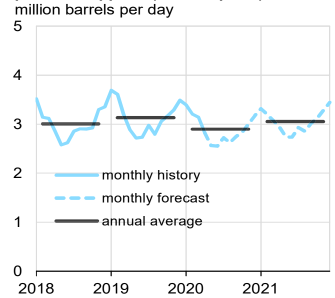

U.S. liquid fuels product supplied
(consumption)
million barrels per day
monthly history
monthly forecast
annual average
2018
2019
2020
2021
Source: Short-Term Energy Outlook, May 2020
Components of annual change
million barrels per day
forecast
1.50
0.55
-0.04
-2.17
motor gasoline
distillate fuel
jet fuel
hydrocarbon gas liquids
other fuels
net change
eia


U.S. gasoline and distillate inventories
million barrels
total motor gasoline inventory
forecast
monthly range from January 2015 - December 2019
total distillate fuel inventory
280
260
240
220
200
180
160
140
120
100
80
60
Jan 2015
Jan 2016
Jan 2017
Jan 2018
Jan 2019
Jan 2020
Jan 2021
Source: Short-Term Energy Outlook, May 2020
eia


U.S. net imports of crude oil and liquid fuels
million barrels per day
forecast
crude oil net imports
total net imports
liquid fuels net imports
10
8
6
4
2
0
-2
-4
-6
Jan 2014
Jan 2015
Jan 2016
Jan 2017
Jan 2018
Jan 2019
Jan 2020
Jan 2021
Note: Liquids fuels include: gasoline, distillate fuels, hydrocarbon gas liquids, jet fuel, residual fuel oil, unfinished oils, other hydrocarbons/oxygenates, and other oils.
Source: Short-Term Energy Outlook, May 2020
eia


U.S. natural gas plant liquids production
million barrels per day
6
5
4
3
2
1
0
monthly production
monthly forecast
annual average
2018
2019
2020
2021
Source: Short-Term Energy Outlook, May 2020
Components of annual change
million barrels per day
forecast
1.0
0.8
0.6
0.4
0.2
0.0
-0.2
-0.4
0.59
0.44
-0.06
-0.09
net change
natural gasoline
butanes
propane
ethane
2018
2019
2020
2021
eia

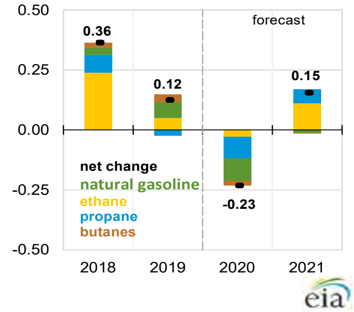
U.S. hydrocarbon gas liquids product supplied (consumption)
million barrels per day



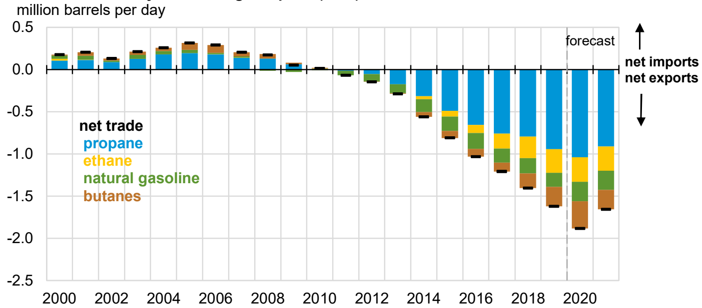
Source: Short-Term Energy Outlook, May 2020

Components of annual change

million barrels per day

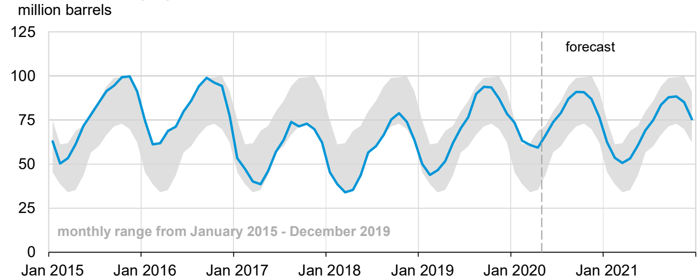


U.S. net trade of hydrocarbon gas liquids (HGL)
million barrels per day



Source: Short-Term Energy Outlook, May 2020

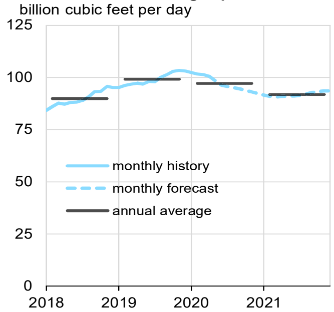
U.S. commercial propane inventories
million barrels



Note: Excludes refinery propylene.

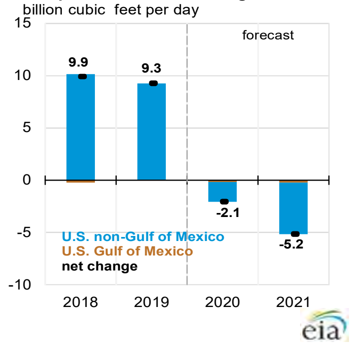
Source: Short-Term Energy Outlook, May 2020

U.S. marketed natural gas production
billion cubic feet per day

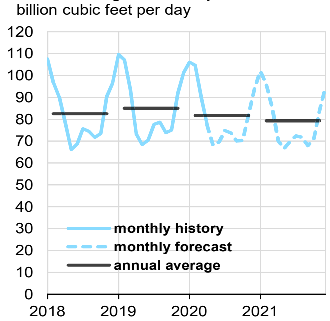


Source: Short-Term Energy Outlook, May 2020

Components of annual change
billion cubic feet per day

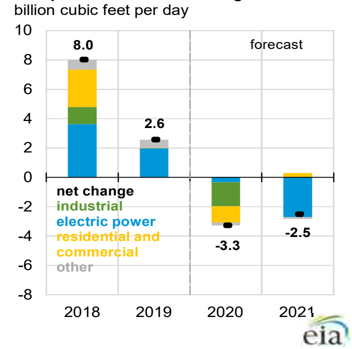


U.S. natural gas consumption
billion cubic feet per day

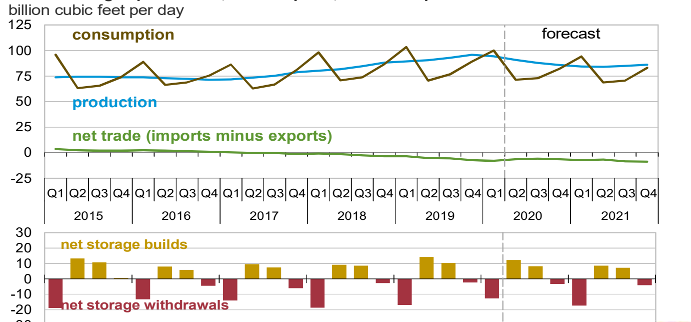


Source: Short-Term Energy Outlook, May 2020

Components of annual change
billion cubic feet per day

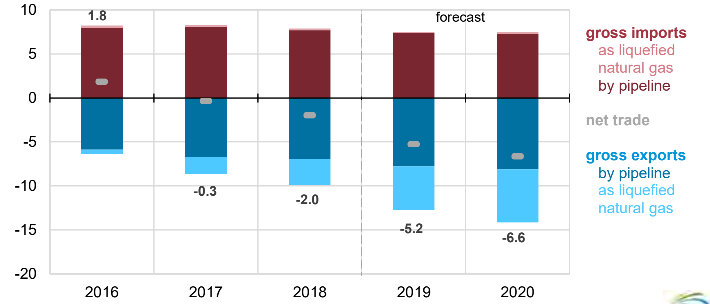


U.S. natural gas production, consumption, and net imports
billion cubic feet per day



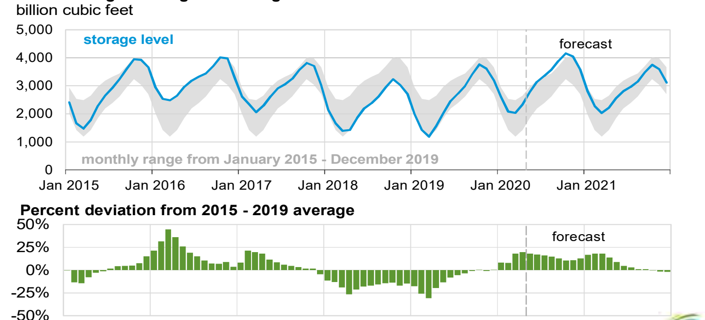
Source: Short-Term Energy Outlook, May 2020

U.S. annual natural gas trade
billion cubic feet per day



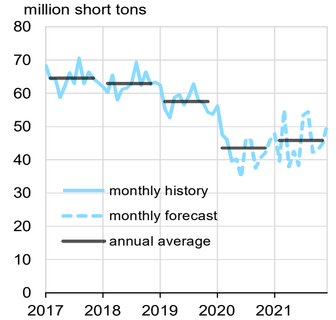
Source: Short-Term Energy Outlook, May 2020

U.S. working natural gas in storage
billion cubic feet

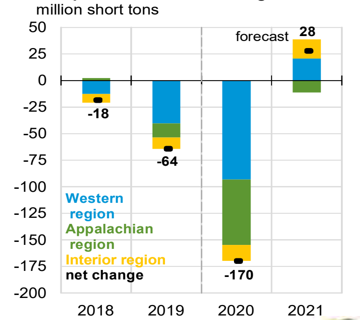


Source: Short-Term Energy Outlook, May 2020

U.S. coal production
million short tons

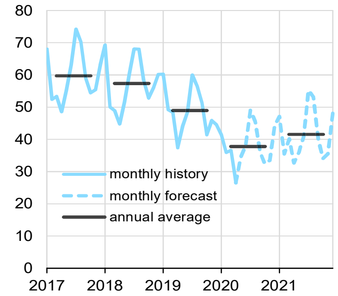


Components of annual change
million short tons

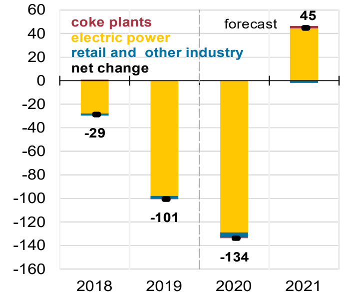


Source: Short-Term Energy Outlook, May 2020

U.S. coal consumption
million short tons

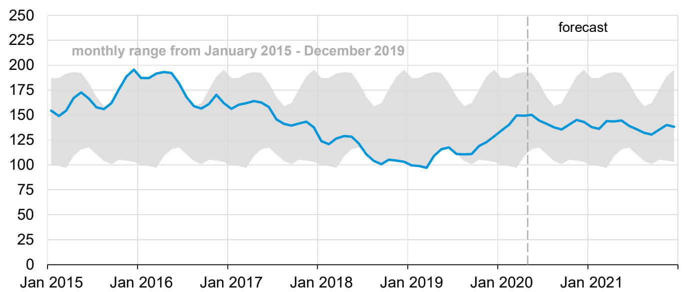


Components of annual change
million short tons



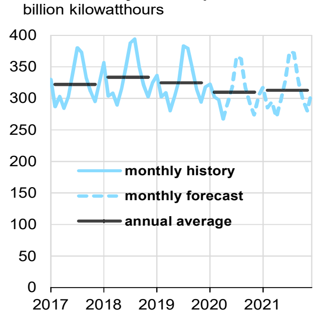
Source: Short-Term Energy Outlook, May 2020

U.S. electric power coal inventories
million short tons

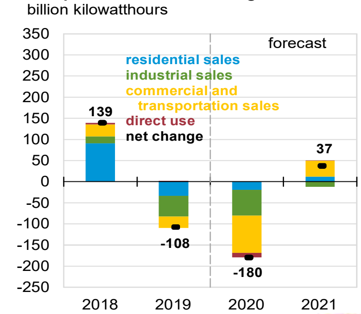


Source: Short-Term Energy Outlook, May 2020

U.S. electricity consumption
billion kilowatthours

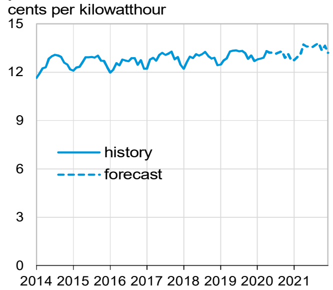


Components of annual change
billion kilowatthours

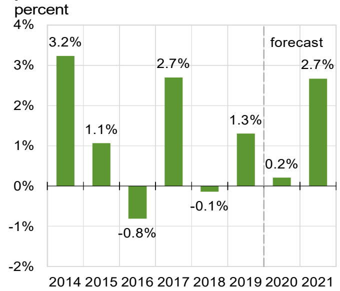


Source: Short-Term Energy Outlook, May 2020

U.S. monthly residential electricity price
cents per kilowatthour

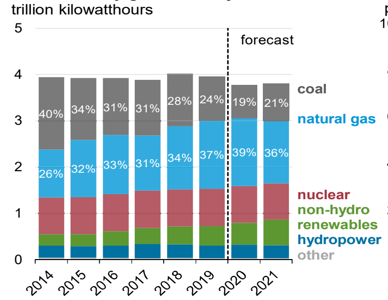


Annual growth in residential electricity prices
percent

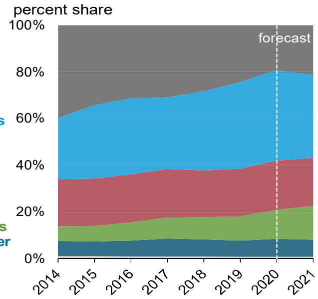


Source: Short-Term Energy Outlook, May 2020

U.S. electricity generation by fuel, all sectors
trillion kilowatthours

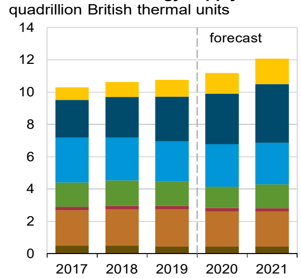


percent share

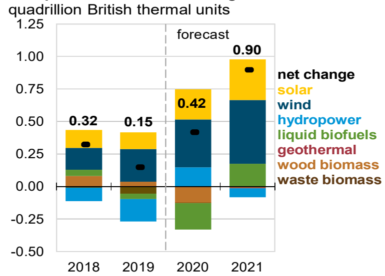


Note: Labels show percentage share of total generation provided by coal and natural gas.
Source: Short-Term Energy Outlook, May 2020

U.S. renewable energy supply
quadrillion British thermal units

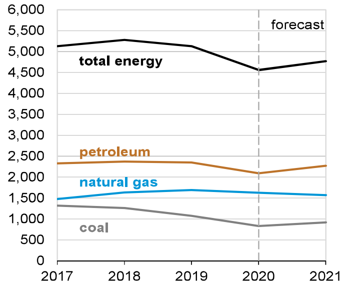


Components of annual change
quadrillion British thermal units

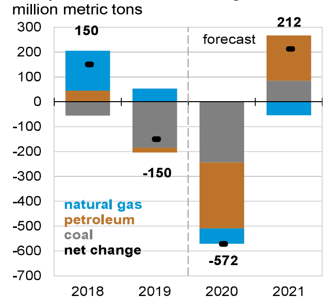


Note: Hydropower excludes pumped storage generation. Liquid biofuels include ethanol and biodiesel. Other biomass includes municipal waste from biogenic sources, landfill gas, and other non-wood waste.
Source: Short-Term Energy Outlook, May 2020

U.S. annual carbon emissions by source
million metric tons

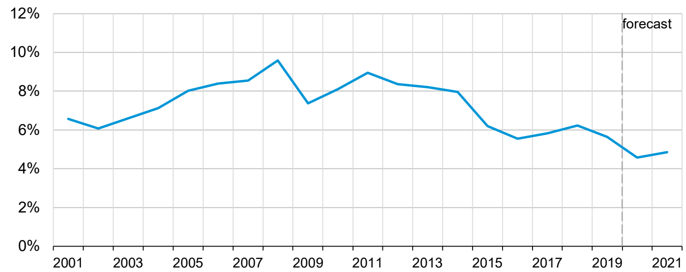


Components of annual change
million metric tons



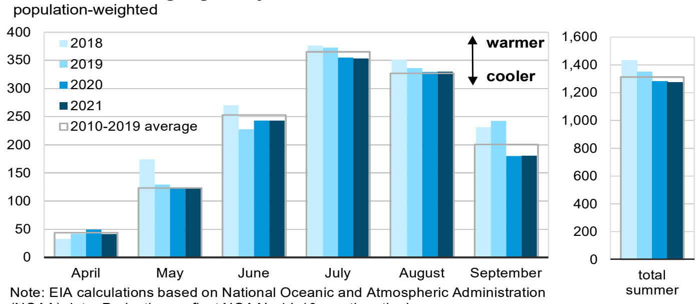
Source: Short-Term Energy Outlook, May 2020

U.S. annual energy expenditures
share of gross domestic product

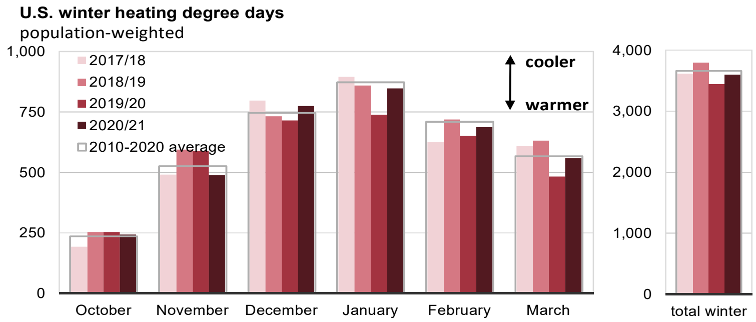


Source: Short-Term Energy Outlook, May 2020

U.S. summer cooling degree days
population-weighted

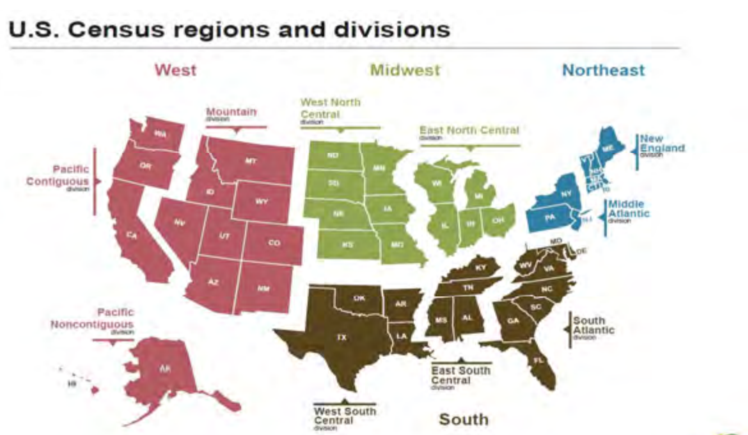


Note: EIA calculations based on National Oceanic and Atmospheric Administration (NOAA) data. Projections reflect NOAA's 14-16 month outlook.
Source: Short-Term Energy Outlook, May 2020



Note: EIA calculations based on National Oceanic and Atmospheric Administration (NOAA) data. Projections reflect NOAA's 14-16 month outlook.

Source: Short-Term Energy Outlook, May 2020



Source: U.S. Energy Information Administration, *Short-Term Energy Outlook*

Table 1. U.S. Energy Markets Summary

U.S. Energy Information Administration | Short-Term Energy Outlook - May 2020

	2019				2020				2021				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2019	2020	2021
Energy Supply															
Crude Oil Production (a) (million barrels per day)	11.81	12.10	12.23	12.78	12.81	11.78	11.23	10.93	10.81	10.89	10.83	11.07	12.23	11.69	10.90
Dry Natural Gas Production (billion cubic feet per day)	89.32	90.50	92.98	95.97	94.28	91.08	88.03	86.05	84.21	84.09	85.03	86.22	92.21	89.84	84.89
Coal Production (million short tons)	170	175	180	165	150	114	130	129	142	119	150	138	690	523	550
Energy Consumption															
Liquid Fuels (million barrels per day)	20.30	20.31	20.67	20.57	19.35	15.87	18.67	19.26	19.18	19.61	20.19	20.18	20.46	18.29	19.79
Natural Gas (billion cubic feet per day)	103.32	70.74	76.74	89.33	100.04	71.60	72.92	82.27	94.20	68.86	70.76	83.07	84.97	81.69	79.17
Coal (b) (million short tons)	158	130	168	132	114	99	131	110	123	109	148	118	587	453	498
Electricity (billion kilowatt hours per day)	10.53	10.02	12.06	10.07	10.13	9.64	11.37	9.46	9.97	9.82	11.66	9.67	10.67	10.15	10.28
Renewables (c) (quadrillion Btu)	2.81	3.08	2.80	2.79	2.94	3.06	2.87	2.92	3.14	3.39	3.11	3.12	11.48	11.80	12.76
Total Energy Consumption (d) (quadrillion Btu)	26.54	23.43	24.97	25.22	25.08	20.50	22.69	23.37	24.49	22.46	23.70	24.07	100.17	91.64	94.72
Energy Prices															
Crude Oil West Texas Intermediate Spot (dollars per barrel)	54.82	59.94	56.35	56.86	45.34	20.64	25.47	29.50	36.63	42.16	45.48	48.53	57.02	30.10	43.31
Natural Gas Henry Hub Spot (dollars per million Btu)	2.92	2.56	2.38	2.40	1.89	1.85	2.11	2.71	2.99	2.74	2.83	2.98	2.57	2.14	2.89
Coal (dollars per million Btu)	2.08	2.05	2.00	1.95	1.97	2.02	1.98	1.99	2.02	2.05	2.03	2.04	2.02	1.99	2.04
Macroeconomic															
Real Gross Domestic Product (billion chained 2012 dollars - SAAR)	18,927	19,022	19,121	19,222	19,048	17,627	17,617	17,885	18,532	19,108	19,455	19,682	19,073	18,044	19,194
Percent change from prior year	2.7	2.3	2.1	2.3	0.6	-7.3	-7.9	-7.0	-2.7	8.4	10.4	10.1	2.3	-5.4	6.4
GDP Implicit Price Deflator (Index, 2012=100)	111.5	112.2	112.7	113.0	113.5	113.8	114.2	114.6	115.0	115.5	115.9	116.2	112.3	114.0	115.7
Percent change from prior year	2.0	1.8	1.7	1.6	1.7	1.5	1.4	1.4	1.4	1.5	1.5	1.4	1.8	1.5	1.4
Real Disposable Personal Income (billion chained 2012 dollars - SAAR)	14,878	14,934	15,012	15,073	15,206	15,536	15,609	15,320	15,442	15,564	15,662	15,758	14,974	15,418	15,606
Percent change from prior year	3.3	3.0	2.7	2.4	2.2	4.0	4.0	1.6	1.6	0.2	0.3	2.9	2.9	3.0	1.2
Manufacturing Production Index (Index, 2012=100)	106.5	105.7	105.9	105.8	103.9	90.0	84.7	83.1	86.5	90.4	92.9	94.6	106.0	90.4	91.1
Percent change from prior year	1.6	0.1	-0.6	-1.1	-2.4	-14.8	-20.0	-21.5	-16.7	0.4	9.7	13.9	0.0	-14.7	0.8
Weather															
U.S. Heating Degree-Days	2,211	481	57	1,559	1,875	505	69	1,506	2,094	483	70	1,504	4,307	3,956	4,151
U.S. Cooling Degree-Days	45	399	952	105	71	416	864	96	46	409	864	96	1,501	1,447	1,415

\- = no data available

Prices are not adjusted for inflation.

(a) Includes lease condensate.

(b) Total consumption includes Independent Power Producer (IPP) consumption.

(c) Renewable energy includes minor components of non-marketed renewable energy that is neither bought nor sold, either directly or indirectly, as inputs to marketed energy.
EIA does not estimate or project end-use consumption of non-marketed renewable energy.

(d) The conversion from physical units to Btu is calculated using a subset of conversion factors used in the calculations of gross energy consumption in EIA's Monthly Energy Review (MER).
Consequently, the historical data may not precisely match those published in the MER or the Annual Energy Review (AER).

Notes: The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Historical data: Latest data available from Energy Information Administration databases supporting the following reports: *Petroleum Supply Monthly* , DOE/EIA-0109; *Petroleum Supply Annual* , DOE/EIA-0340/2; *Weekly Petroleum Status Report* , DOE/EIA-0208; *Petroleum Marketing Monthly* , DOE/EIA-0380; *Natural Gas Monthly* , DOE/EIA-0130; *Electric Power Monthly* , DOE/EIA-0226; *Quarterly Coal Report* , DOE/EIA-0121; and *International Petroleum Monthly* , DOE/EIA-0520.

Minor discrepancies with published historical data are due to independent rounding.

Projections: EIA Regional Short-Term Energy Model. U.S. macroeconomic projections are based on the IHS Markit model of the U.S. Economy.
Weather projections from National Oceanic and Atmospheric Administration.

Table 2. Energy Prices

U.S. Energy Information Administration | Short-Term Energy Outlook - May 2020

	2019				2020				2021				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2019	2020	2021
Crude Oil (dollars per barrel)															
West Texas Intermediate Spot Average	**54.82**	**59.94**	**56.35**	**56.86**	**45.34**	*20.64*	*25.47*	*29.50*	*36.63*	*42.16*	*45.48*	*48.53*	**57.02**	*30.10*	*43.31*
Brent Spot Average	**63.14**	**69.07**	**61.90**	**63.30**	**50.00**	*23.11*	*29.97*	*34.00*	*41.13*	*46.66*	*49.98*	*53.03*	**64.37**	*34.13*	*47.81*
U.S. Imported Average	**55.25**	**62.98**	**57.30**	**55.57**	**42.88**	*17.35*	*22.53*	*26.48*	*34.13*	*39.67*	*42.99*	*46.01*	**57.94**	*27.31*	*41.02*
U.S. Refiner Average Acquisition Cost	**56.93**	**63.55**	**58.67**	**58.05**	**45.37**	*19.61*	*24.93*	*28.99*	*35.52*	*41.20*	*44.49*	*47.53*	**59.33**	*30.23*	*42.34*
U.S. Liquid Fuels (cents per gallon)															
Refiner Prices for Resale															
Gasoline	**167**	**205**	**189**	**182**	**148**	*83*	*105*	*107*	*120*	*151*	*154*	*148*	**186**	*112*	*144*
Diesel Fuel	**192**	**203**	**192**	**197**	**157**	*95*	*106*	*116*	*127*	*150*	*159*	*166*	**196**	*119*	*151*
Heating Oil	**189**	**195**	**184**	**191**	**155**	*86*	*94*	*108*	*128*	*144*	*155*	*165*	**190**	*113*	*139*
Refiner Prices to End Users															
Jet Fuel	**193**	**204**	**194**	**197**	**160**	*83*	*103*	*113*	*127*	*149*	*158*	*165*	**197**	*120*	*151*
No. 6 Residual Fuel Oil (a)	**153**	**163**	**155**	**162**	**161**	*80*	*91*	*103*	*86*	*97*	*104*	*111*	**158**	*105*	*100*
Retail Prices Including Taxes															
Gasoline Regular Grade (b)	**236**	**279**	**265**	**259**	**241**	*191*	*187*	*181*	*189*	*226*	*230*	*222*	**260**	*200*	*217*
Gasoline All Grades (b)	**245**	**288**	**274**	**269**	**250**	*202*	*199*	*194*	*202*	*239*	*243*	*235*	**269**	*212*	*231*
On-highway Diesel Fuel	**302**	**312**	**302**	**306**	**289**	*222*	*212*	*222*	*227*	*249*	*260*	*269*	**306**	*237*	*252*
Heating Oil	**300**	**305**	**290**	**301**	**282**	*208*	*200*	*220*	*230*	*242*	*256*	*276*	**300**	*241*	*250*
Natural Gas															
Henry Hub Spot (dollars per thousand cubic feet)	**3.03**	**2.66**	**2.47**	**2.49**	**1.96**	*1.92*	*2.19*	*2.81*	*3.11*	*2.85*	*2.94*	*3.09*	**2.66**	*2.22*	*3.00*
Henry Hub Spot (dollars per million Btu)	**2.92**	**2.56**	**2.38**	**2.40**	**1.89**	*1.85*	*2.11*	*2.71*	*2.99*	*2.74*	*2.83*	*2.98*	**2.57**	*2.14*	*2.89*
U.S. Retail Prices (dollars per thousand cubic feet)															
Industrial Sector	**4.67**	**3.74**	**3.30**	**3.74**	**3.48**	*2.74*	*2.91*	*3.74*	*4.32*	*3.74*	*3.77*	*4.22*	**3.91**	*3.24*	*4.03*
Commercial Sector	**7.59**	**7.97**	**8.40**	**7.22**	**7.18**	*7.34*	*7.81*	*7.24*	*7.43*	*8.04*	*8.51*	*7.77*	**7.62**	*7.29*	*7.75*
Residential Sector	**9.47**	**12.48**	**18.10**	**9.88**	**9.48**	*11.65*	*16.37*	*10.01*	*9.38*	*12.34*	*17.10*	*10.59*	**10.56**	*10.52*	*10.74*
U.S. Electricity															
Power Generation Fuel Costs (dollars per million Btu)															
Coal	**2.08**	**2.05**	**2.00**	**1.95**	**1.97**	*2.02*	*1.98*	*1.99*	*2.02*	*2.05*	*2.03*	*2.04*	**2.02**	*1.99*	*2.04*
Natural Gas	**3.71**	**2.73**	**2.51**	**2.78**	**2.37**	*1.94*	*2.08*	*2.98*	*3.53*	*2.93*	*2.96*	*3.32*	**2.88**	*2.31*	*3.15*
Residual Fuel Oil (c)	**12.21**	**13.39**	**12.79**	**12.52**	**12.20**	*7.37*	*6.13*	*6.53*	*7.46*	*9.44*	*9.47*	*9.75*	**12.72**	*7.91*	*8.82*
Distillate Fuel Oil	**14.83**	**15.77**	**15.01**	**15.10**	**13.05**	*8.06*	*8.56*	*9.37*	*10.10*	*11.80*	*12.38*	*13.05*	**15.16**	*9.77*	*11.83*
Retail Prices (cents per kilowatthour)															
Industrial Sector	**6.66**	**6.71**	**7.25**	**6.66**	**6.41**	*6.62*	*7.28*	*6.81*	*6.71*	*6.88*	*7.52*	*6.90*	**6.83**	*6.78*	*7.02*
Commercial Sector	**10.43**	**10.64**	**11.00**	**10.53**	**10.29**	*10.47*	*10.86*	*10.50*	*10.39*	*10.72*	*11.21*	*10.84*	**10.66**	*10.54*	*10.81*
Residential Sector	**12.68**	**13.33**	**13.27**	**12.85**	**12.85**	*13.24*	*13.22*	*12.91*	*12.92*	*13.64*	*13.68*	*13.38*	**13.04**	*13.06*	*13.41*

- = no data available
Prices are not adjusted for inflation.
(a) Average for all sulfur contents.
(b) Average self-service cash price.
(c) Includes fuel oils No. 4, No. 5, No. 6, and topped crude.

Notes: The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.
Prices exclude taxes unless otherwise noted.

Historical data: Latest data available from Energy Information Administration databases supporting the following reports: *Petroleum Marketing Monthly* , DOE/EIA-0380;
Weekly Petroleum Status Report , DOE/EIA-0208; *Natural Gas Monthly* , DOE/EIA-0130; *Electric Power Monthly* , DOE/EIA-0226; and *Monthly Energy Review* , DOE/EIA-0035.
WTI and Brent crude oils, and Henry Hub natural gas spot prices from Reuter's News Service (http://www.reuters.com).
Minor discrepancies with published historical data are due to independent rounding.

Projections: EIA Regional Short-Term Energy Model.

Table 3a. International Petroleum and Other Liquids Production, Consumption, and Inventories
U.S. Energy Information Administration | Short-Term Energy Outlook - May 2020

	2019				2020				2021				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2019	2020	2021
Supply (million barrels per day) (a)															
OECD	31.04	31.29	31.45	32.75	32.94	29.60	29.56	29.93	29.80	30.14	30.25	31.02	31.64	30.50	30.31
U.S. (50 States)	18.85	19.32	19.42	20.21	20.27	18.52	18.06	17.87	17.61	18.03	18.07	18.41	19.45	18.68	18.03
Canada	5.44	5.47	5.47	5.62	5.65	4.41	4.86	5.28	5.35	5.43	5.47	5.70	5.50	5.05	5.49
Mexico	1.91	1.91	1.93	1.93	1.99	1.81	1.77	1.74	1.79	1.80	1.76	1.74	1.92	1.83	1.77
Other OECD	4.85	4.59	4.63	4.99	5.02	4.86	4.86	5.03	5.06	4.88	4.95	5.17	4.77	4.94	5.01
Non-OECD	69.27	69.08	68.68	68.74	67.84	63.37	63.07	64.50	66.35	67.45	68.03	67.84	68.94	64.69	67.42
OPEC	35.45	34.90	33.93	34.19	33.59	31.15	30.09	31.50	33.21	33.35	33.39	33.42	34.61	31.58	33.35
Crude Oil Portion	29.94	29.47	28.66	29.02	28.28	26.14	25.23	26.64	28.26	28.46	28.51	28.54	29.27	26.57	28.44
Other Liquids (b)	5.51	5.43	5.28	5.17	5.31	5.01	4.87	4.87	4.95	4.89	4.88	4.89	5.34	5.01	4.90
Eurasia	14.87	14.43	14.59	14.67	14.74	13.15	13.26	13.48	13.85	14.06	14.22	14.32	14.64	13.66	14.11
China	4.89	4.92	4.89	4.88	4.95	4.80	4.80	4.82	4.82	4.85	4.85	4.89	4.89	4.84	4.85
Other Non-OECD	14.07	14.83	15.27	15.01	14.56	14.26	14.91	14.69	14.47	15.19	15.57	15.21	14.80	14.60	15.11
Total World Supply	100.31	100.37	100.13	101.49	100.78	92.97	92.63	94.43	96.15	97.59	98.27	98.86	100.58	95.19	97.73
Non-OPEC Supply	64.87	65.47	66.20	67.30	67.19	61.81	62.53	62.92	62.94	64.24	64.88	65.44	65.97	63.61	64.38
Consumption (million barrels per day) (c)															
OECD	47.41	46.71	47.83	47.50	44.25	36.29	43.44	45.14	44.96	44.69	45.97	46.12	47.36	42.29	45.44
U.S. (50 States)	20.30	20.31	20.67	20.57	19.35	15.87	18.67	19.26	19.18	19.61	20.19	20.18	20.46	18.29	19.79
U.S. Territories	0.12	0.11	0.12	0.13	0.12	0.11	0.13	0.14	0.14	0.12	0.13	0.13	0.12	0.12	0.13
Canada	2.45	2.44	2.57	2.54	2.42	1.70	2.19	2.28	2.38	2.33	2.43	2.40	2.50	2.15	2.38
Europe	13.90	14.04	14.53	13.94	12.68	10.85	13.31	13.66	13.19	13.38	13.87	13.58	14.11	12.63	13.51
Japan	4.09	3.41	3.44	3.76	3.54	2.48	3.12	3.50	3.77	3.10	3.18	3.50	3.67	3.16	3.39
Other OECD	6.55	6.40	6.49	6.55	6.14	5.29	6.02	6.30	6.31	6.15	6.18	6.32	6.50	5.94	6.24
Non-OECD	52.58	53.54	53.55	53.81	49.89	45.19	52.22	53.91	53.21	54.39	54.49	54.50	53.38	50.32	54.15
Eurasia	4.83	4.90	5.17	5.12	4.77	3.91	5.03	5.08	4.87	4.94	5.32	5.17	5.01	4.70	5.08
Europe	0.76	0.76	0.78	0.78	0.77	0.73	0.76	0.78	0.75	0.75	0.77	0.77	0.77	0.76	0.76
China	14.38	14.67	14.39	14.61	12.31	12.99	14.36	14.87	14.99	15.19	14.90	15.12	14.51	13.64	15.05
Other Asia	13.95	13.98	13.63	13.93	13.40	11.15	13.14	14.06	14.24	14.40	13.99	14.34	13.87	12.94	14.24
Other Non-OECD	18.66	19.22	19.59	19.38	18.64	16.40	18.92	19.12	18.37	19.10	19.53	19.10	19.21	18.28	19.03
Total World Consumption	99.99	100.25	101.38	101.31	94.14	81.48	95.66	99.05	98.18	99.08	100.46	100.63	100.74	92.61	99.60
Total Crude Oil and Other Liquids Inventory Net Withdrawals (million barrels per day)															
U.S. (50 States)	0.26	-0.64	0.05	0.29	-0.32	-1.87	0.13	0.72	0.33	-0.29	-0.01	0.42	-0.01	-0.33	0.11
Other OECD	-0.21	0.02	-0.16	0.26	-1.85	-2.97	0.94	1.27	0.55	0.56	0.71	0.43	-0.02	-0.64	0.56
Other Stock Draws and Balance	-0.38	0.50	1.36	-0.74	-4.47	-6.65	1.97	2.64	1.14	1.22	1.50	0.91	0.19	-1.61	1.19
Total Stock Draw	-0.33	-0.12	1.25	-0.18	-6.63	-11.49	3.04	4.62	2.02	1.49	2.19	1.76	0.16	-2.58	1.87
End-of-period Commercial Crude Oil and Other Liquids Inventories (million barrels)															
U.S. Commercial Inventory	1,241	1,304	1,299	1,282	1,311	1,458	1,446	1,393	1,376	1,405	1,408	1,372	1,282	1,393	1,372
OECD Commercial Inventory	2,858	2,919	2,929	2,888	3,085	3,502	3,404	3,235	3,168	3,146	3,083	3,007	2,888	3,235	3,007

\- = no data available

OECD = Organization for Economic Cooperation and Development: Australia, Austria, Belgium, Canada, Chile, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Japan, Latvia, Lithuania, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Poland, Portugal, Slovakia, Slovenia, South Korea, Spain, Sweden, Switzerland, Turkey, the United Kingdom, the United States.

OPEC = Organization of the Petroleum Exporting Countries: Algeria, Angola, Congo (Brazzaville), Equatorial Guinea, Gabon, Iran, Iraq, Kuwait, Libya, Nigeria, Saudi Arabia, the United Arab Emirates, Venezuela.

(a) Supply includes production of crude oil (including lease condensates), natural gas plant liquids, biofuels, other liquids, and refinery processing gains.

(b) Includes lease condensate, natural gas plant liquids, other liquids, and refinery processing gain. Includes other unaccounted-for liquids.

(c) Consumption of petroleum by the OECD countries is synonymous with "petroleum product supplied," defined in the glossary of the EIA *Petroleum Supply Monthly* , DOE/EIA-0109. Consumption of petroleum by the non-OECD countries is "apparent consumption," which includes internal consumption, refinery fuel and loss, and bunkering.

Notes: The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Historical data: Latest data available from Energy Information Administration international energy statistics.

Minor discrepancies with published historical data are due to independent rounding.

Projections: EIA Regional Short-Term Energy Model.

Table 3b. Non-OPEC Petroleum and Other Liquids Supply (million barrels per day)

U.S. Energy Information Administration | Short-Term Energy Outlook - May 2020

	2019				2020				2021				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2019	2020	2021
North America	26.19	26.70	26.82	27.76	27.92	24.74	24.69	24.90	24.75	25.26	25.30	25.85	26.87	25.56	25.29
Canada	5.44	5.47	5.47	5.62	5.65	4.41	4.86	5.28	5.35	5.43	5.47	5.70	5.50	5.05	5.49
Mexico	1.91	1.91	1.93	1.93	1.99	1.81	1.77	1.74	1.79	1.80	1.76	1.74	1.92	1.83	1.77
United States	18.85	19.32	19.42	20.21	20.27	18.52	18.06	17.87	17.61	18.03	18.07	18.41	19.45	18.68	18.03
Central and South America	5.44	6.22	6.80	6.45	5.97	6.05	6.65	6.33	6.04	6.82	7.21	6.87	6.23	6.25	6.74
Argentina	0.66	0.70	0.70	0.70	0.67	0.66	0.67	0.67	0.66	0.67	0.68	0.67	0.69	0.67	0.67
Brazil	2.90	3.65	4.23	3.89	3.39	3.66	4.08	3.73	3.44	4.28	4.65	4.27	3.67	3.71	4.16
Colombia	0.92	0.92	0.91	0.91	0.90	0.83	0.84	0.88	0.89	0.83	0.84	0.87	0.92	0.86	0.86
Ecuador	0.53	0.53	0.55	0.52	0.53	0.39	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.50	0.53
Other Central and S. America	0.42	0.41	0.42	0.43	0.48	0.51	0.52	0.53	0.52	0.51	0.52	0.52	0.42	0.51	0.52
Europe	4.26	3.97	3.96	4.29	4.45	4.34	4.30	4.44	4.47	4.30	4.37	4.60	4.12	4.38	4.44
Norway	1.79	1.58	1.66	1.96	2.05	2.00	2.03	2.07	2.12	2.06	2.10	2.20	1.75	2.04	2.12
United Kingdom	1.25	1.17	1.11	1.15	1.23	1.22	1.10	1.18	1.17	1.08	1.10	1.23	1.17	1.18	1.15
Eurasia	14.87	14.43	14.59	14.67	14.74	13.15	13.26	13.48	13.85	14.06	14.22	14.32	14.64	13.66	14.11
Azerbaijan	0.82	0.79	0.78	0.77	0.78	0.66	0.69	0.71	0.74	0.74	0.74	0.74	0.79	0.71	0.74
Kazakhstan	2.03	1.85	1.96	2.02	2.06	1.78	1.85	1.89	1.96	1.88	1.93	1.95	1.97	1.89	1.93
Russia	11.58	11.41	11.48	11.50	11.52	10.32	10.34	10.50	10.79	11.07	11.18	11.26	11.49	10.67	11.08
Turkmenistan	0.29	0.23	0.22	0.23	0.25	0.25	0.25	0.25	0.24	0.24	0.24	0.24	0.24	0.25	0.24
Other Eurasia	0.15	0.15	0.15	0.15	0.14	0.14	0.14	0.14	0.13	0.13	0.13	0.13	0.15	0.14	0.13
Middle East	3.11	3.11	3.12	3.12	3.21	3.09	3.10	3.13	3.19	3.19	3.19	3.19	3.11	3.13	3.19
Oman	0.98	0.98	0.98	0.98	1.01	0.88	0.89	0.92	0.94	0.94	0.94	0.94	0.98	0.93	0.94
Qatar	2.00	2.00	2.00	2.00	2.06	2.06	2.06	2.06	2.10	2.10	2.10	2.10	2.00	2.06	2.10
Asia and Oceania	9.48	9.51	9.36	9.47	9.43	8.98	9.07	9.20	9.24	9.22	9.22	9.24	9.45	9.17	9.23
Australia	0.42	0.47	0.51	0.54	0.49	0.52	0.53	0.55	0.54	0.53	0.53	0.52	0.49	0.52	0.53
China	4.89	4.92	4.89	4.88	4.95	4.80	4.80	4.82	4.82	4.85	4.85	4.89	4.89	4.84	4.85
India	1.01	0.99	0.98	0.99	0.94	0.79	0.81	0.88	0.92	0.90	0.92	0.91	0.99	0.86	0.91
Indonesia	0.93	0.93	0.91	0.91	0.91	0.89	0.89	0.88	0.86	0.86	0.85	0.85	0.92	0.89	0.86
Malaysia	0.75	0.73	0.65	0.72	0.72	0.61	0.65	0.66	0.68	0.67	0.67	0.66	0.71	0.66	0.67
Vietnam	0.25	0.25	0.23	0.22	0.22	0.21	0.21	0.21	0.20	0.20	0.20	0.19	0.24	0.21	0.20
Africa	1.52	1.54	1.55	1.55	1.47	1.47	1.46	1.45	1.39	1.37	1.37	1.37	1.54	1.46	1.38
Egypt	0.66	0.65	0.65	0.65	0.60	0.60	0.60	0.60	0.56	0.56	0.56	0.56	0.65	0.60	0.56
South Sudan	0.17	0.18	0.18	0.18	0.18	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.18	0.19	0.19
Total non-OPEC liquids	64.87	65.47	66.20	67.30	67.19	61.81	62.53	62.92	62.94	64.24	64.88	65.44	65.97	63.61	64.38
OPEC non-crude liquids	5.51	5.43	5.28	5.17	5.31	5.01	4.87	4.87	4.95	4.89	4.88	4.89	5.34	5.01	4.90
Non-OPEC + OPEC non-crude	70.37	70.90	71.48	72.47	72.50	66.83	67.40	67.79	67.89	69.13	69.76	70.33	71.31	68.62	69.29
Unplanned non-OPEC Production Outages	0.35	0.26	0.39	0.30	0.14	n/a	n/a	n/a	n/a	n/a	n/a	n/a	0.32	n/a	n/a

\- = no data available

OPEC = Organization of the Petroleum Exporting Countries: Algeria, Angola, Congo (Brazzaville), Equatorial Guinea, Gabon, Iran, Iraq, Kuwait, Libya, Nigeria, Saudi Arabia, the United Arab Emirates, Venezuela.

Notes: The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Supply includes production of crude oil (including lease condensates), natural gas plant liquids, biofuels, other liquids, and refinery processing gains.

Not all countries are shown in each region and sum of reported country volumes may not equal regional volumes.

Historical data: Latest data available from Energy Information Administration international energy statistics.

Minor discrepancies with published historical data are due to independent rounding.

Projections: EIA Regional Short-Term Energy Model.

Table 3c. OPEC Crude Oil (excluding condensates) Supply (million barrels per day)

U.S. Energy Information Administration | Short-Term Energy Outlook - May 2020

	2019				2020				2021				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2019	2020	2021
Crude Oil															
Algeria	1.01	1.02	1.02	1.02	1.02	-	-	-	-	-	-	-	1.02	-	-
Angola	1.50	1.43	1.40	1.36	1.36	-	-	-	-	-	-	-	1.42	-	-
Congo (Brazzaville)	0.33	0.33	0.33	0.32	0.29	-	-	-	-	-	-	-	0.32	-	-
Equatorial Guinea	0.11	0.11	0.13	0.13	0.13	-	-	-	-	-	-	-	0.12	-	-
Gabon	0.20	0.20	0.20	0.20	0.20	-	-	-	-	-	-	-	0.20	-	-
Iran	2.63	2.33	2.10	2.03	2.02	-	-	-	-	-	-	-	2.27	-	-
Iraq	4.75	4.70	4.70	4.65	4.56	-	-	-	-	-	-	-	4.70	-	-
Kuwait	2.74	2.72	2.70	2.70	2.77	-	-	-	-	-	-	-	2.72	-	-
Libya	0.93	1.14	1.13	1.17	0.35	-	-	-	-	-	-	-	1.09	-	-
Nigeria	1.58	1.65	1.71	1.67	1.71	-	-	-	-	-	-	-	1.65	-	-
Saudi Arabia	10.00	9.92	9.38	9.83	9.80	-	-	-	-	-	-	-	9.78	-	-
United Arab Emirates	3.12	3.12	3.13	3.20	3.30	-	-	-	-	-	-	-	3.14	-	-
Venezuela	1.05	0.79	0.73	0.73	0.77	-	-	-	-	-	-	-	0.83	-	-
OPEC Total	29.94	29.47	28.66	29.02	28.28	26.14	25.23	26.64	28.26	28.46	28.51	28.54	29.27	26.57	28.44
Other Liquids (a)	5.51	5.43	5.28	5.17	5.31	5.01	4.87	4.87	4.95	4.89	4.88	4.89	5.34	5.01	4.90
Total OPEC Supply	35.45	34.90	33.93	34.19	33.59	31.15	30.09	31.50	33.21	33.35	33.39	33.42	34.61	31.58	33.35
Crude Oil Production Capacity															
Middle East	25.66	25.53	24.58	24.74	25.61	26.01	26.06	26.17	26.27	26.29	26.28	26.28	25.12	25.96	26.28
Other	6.71	6.68	6.65	6.60	5.82	4.92	4.92	5.49	5.86	5.86	5.91	5.94	6.66	5.29	5.89
OPEC Total	32.37	32.22	31.22	31.34	31.43	30.93	30.98	31.66	32.13	32.15	32.19	32.22	31.78	31.25	32.17
Surplus Crude Oil Production Capacity															
Middle East	2.43	2.75	2.57	2.32	3.15	4.79	5.75	5.03	3.87	3.69	3.68	3.68	2.52	4.68	3.73
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OPEC Total	2.43	2.75	2.57	2.32	3.15	4.79	5.75	5.03	3.87	3.69	3.68	3.68	2.52	4.68	3.73
Unplanned OPEC Production Outages	2.52	2.51	3.24	2.91	3.67	n/a	n/a	n/a	n/a	n/a	n/a	n/a	2.80	n/a	n/a

- = no data available

OPEC = Organization of the Petroleum Exporting Countries: Iran, Iraq, Kuwait, Saudi Arabia, and the United Arab Emirates (Middle East); Algeria, Angola, Congo (Brazzaville), Equatorial Guinea, Gabon, Libya, Nigeria, and Venezuela (Other).

(a) Includes lease condensate, natural gas plant liquids, other liquids, and refinery processing gain. Includes other unaccounted-for liquids.

Notes: The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Historical data: Latest data available from Energy Information Administration international energy statistics.

Minor discrepancies with published historical data are due to independent rounding.

Projections: EIA Regional Short-Term Energy Model.

Table 3d. World Petroleum and Other Liquids Consumption (million barrels per day)
U.S. Energy Information Administration | Short-Term Energy Outlook - May 2020

	2019				2020				2021						
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2019	2020	2021
North America	24.69	24.70	25.19	24.98	23.61	19.01	22.60	23.37	23.33	23.72	24.39	24.37	24.89	22.15	23.96
Canada	2.45	2.44	2.57	2.54	2.42	1.70	2.19	2.28	2.38	2.33	2.43	2.40	2.50	2.15	2.38
Mexico	1.93	1.94	1.93	1.86	1.83	1.43	1.73	1.82	1.76	1.78	1.77	1.78	1.92	1.70	1.77
United States	20.30	20.31	20.67	20.57	19.35	15.87	18.67	19.26	19.18	19.61	20.19	20.18	20.46	18.29	19.79
Central and South America	6.67	6.86	6.91	6.93	6.68	5.44	6.54	6.80	6.52	6.68	6.81	6.82	6.84	6.37	6.71
Brazil	3.01	3.14	3.18	3.18	3.05	2.43	2.99	3.13	3.00	3.08	3.18	3.18	3.13	2.90	3.11
Europe	14.67	14.81	15.31	14.73	13.45	11.58	14.07	14.44	13.94	14.14	14.63	14.35	14.88	13.39	14.27
Eurasia	4.83	4.90	5.17	5.12	4.77	3.91	5.03	5.08	4.87	4.94	5.32	5.17	5.01	4.70	5.08
Russia	3.67	3.76	3.97	3.91	3.60	2.77	3.79	3.82	3.66	3.75	4.07	3.91	3.83	3.49	3.85
Middle East	8.19	8.55	8.94	8.53	8.13	7.46	8.69	8.33	7.96	8.51	8.90	8.25	8.55	8.15	8.41
Asia and Oceania	36.43	35.92	35.42	36.39	32.95	29.91	34.34	36.35	36.99	36.51	35.91	36.96	36.04	33.40	36.59
China	14.38	14.67	14.39	14.61	12.31	12.99	14.36	14.87	14.99	15.19	14.90	15.12	14.51	13.64	15.05
Japan	4.09	3.41	3.44	3.76	3.54	2.48	3.12	3.50	3.77	3.10	3.18	3.50	3.67	3.16	3.39
India	4.82	4.76	4.49	4.73	4.58	3.79	4.29	4.78	4.91	4.97	4.64	4.93	4.70	4.36	4.86
Africa	4.51	4.51	4.43	4.63	4.55	4.17	4.39	4.68	4.57	4.58	4.50	4.70	4.52	4.45	4.59
Total OECD Liquid Fuels Consumption	47.41	46.71	47.83	47.50	44.25	36.29	43.44	45.14	44.96	44.69	45.97	46.12	47.36	42.29	45.44
Total non-OECD Liquid Fuels Consumption	52.58	53.54	53.55	53.81	49.89	45.19	52.22	53.91	53.21	54.39	54.49	54.50	53.38	50.32	54.15
Total World Liquid Fuels Consumption	99.99	100.25	101.38	101.31	94.14	81.48	95.66	99.05	98.18	99.08	100.46	100.63	100.74	92.61	99.60
Oil-weighted Real Gross Domestic Product (a)															
World Index, 2015 Q1 = 100	111.8	112.6	112.9	112.8	109.6	104.7	107.4	109.8	112.7	114.8	116.1	116.8	112.5	107.9	115.1
Percent change from prior year	2.2	2.1	1.9	1.7	-1.9	-7.1	-4.8	-2.6	2.9	9.7	8.1	6.3	2.0	-4.1	6.7
OECD Index, 2015 Q1 = 100	108.7	109.7	110.1	109.7	108.1	99.0	101.4	104.3	107.9	110.7	112.0	112.2	109.6	103.2	110.7
Percent change from prior year	1.8	1.8	1.8	1.6	-0.5	-9.7	-7.9	-4.9	-0.2	11.7	10.5	7.6	1.7	-5.8	7.3
Non-OECD Index, 2015 Q1 = 100	114.7	115.4	115.5	115.8	111.0	110.2	113.3	115.3	117.5	118.9	120.0	121.2	115.4	112.5	119.4
Percent change from prior year	2.6	2.4	2.0	1.8	-3.2	-4.5	-1.9	-0.4	5.8	7.9	5.9	5.1	2.2	-2.5	6.2
Real U.S. Dollar Exchange Rate (a)															
Index, 2015 Q1 = 100	105.27	105.90	106.40	106.22	106.87	109.37	109.22	108.43	107.40	106.70	106.13	105.25	105.95	108.47	106.37
Percent change from prior year	4.6	3.1	0.8	0.0	1.5	3.3	2.6	2.1	0.5	-2.4	-2.8	-2.9	2.1	2.4	-1.9

- = no data available

OECD = Organization for Economic Cooperation and Development: Australia, Austria, Belgium, Canada, Chile, the Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Japan, Latvia, Lithuania, Luxembourg, Mexico, the Netherlands, New Zealand, Norway, Poland, Portugal, Slovakia, Slovenia, South Korea, Spain, Sweden, Switzerland, Turkey, the United Kingdom, the United States.

(a) Weighted geometric mean of real indices for various countries with weights equal to each country's share of world oil consumption in the base period. Exchange rate is measured in foreign currency per U.S. dollar. GDP and exchange rate data are from Oxford Economics, and oil consumption data are from EIA.

Notes: The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Historical data: Latest data available from Energy Information Administration international energy statistics.

Minor discrepancies with published historical data are due to independent rounding.

Projections: EIA Regional Short-Term Energy Model.

Table 4a. U.S. Petroleum and Other Liquids Supply, Consumption, and Inventories
U.S. Energy Information Administration | Short-Term Energy Outlook - May 2020

	2019				2020				2021				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2019	2020	2021
Supply (million barrels per day)															
Crude Oil Supply															
Domestic Production (a)	11.81	12.10	12.23	12.78	12.81	11.78	11.23	10.93	10.81	10.89	10.83	11.07	12.23	11.69	10.90
Alaska	0.49	0.47	0.43	0.48	0.49	0.44	0.45	0.49	0.50	0.50	0.46	0.49	0.47	0.46	0.49
Federal Gulf of Mexico (b)	1.85	1.93	1.82	1.94	2.01	1.89	1.91	1.91	1.97	1.94	1.86	1.88	1.88	1.93	1.91
Lower 48 States (excl GOM)	9.47	9.70	9.98	10.36	10.32	9.46	8.87	8.54	8.33	8.45	8.51	8.70	9.88	9.29	8.50
Crude Oil Net Imports (c)	4.25	4.14	3.95	2.94	2.87	2.56	3.24	4.18	4.50	5.16	5.56	5.29	3.82	3.21	5.13
SPR Net Withdrawals	0.00	0.05	0.00	0.11	0.00	-0.25	0.00	0.14	0.14	0.03	0.01	0.03	0.04	-0.03	0.05
Commercial Inventory Net Withdrawals	-0.19	-0.05	0.41	-0.07	-0.57	-1.05	0.28	0.17	-0.17	0.19	0.25	0.02	0.03	-0.29	0.07
Crude Oil Adjustment (d)	0.33	0.53	0.38	0.56	0.66	0.10	0.21	0.15	0.22	0.22	0.23	0.16	0.45	0.28	0.21
Total Crude Oil Input to Refineries	16.20	16.76	16.97	16.32	15.78	13.13	14.95	15.58	15.50	16.48	16.87	16.56	16.56	14.86	16.36
Other Supply															
Refinery Processing Gain	1.06	1.07	1.07	1.10	1.07	0.93	1.01	1.10	1.09	1.14	1.13	1.13	1.08	1.03	1.12
Natural Gas Plant Liquids Production	4.66	4.81	4.80	4.99	5.04	4.79	4.63	4.56	4.42	4.64	4.76	4.84	4.81	4.75	4.67
Renewables and Oxygenate Production (e)	1.10	1.14	1.12	1.12	1.12	0.83	0.99	1.07	1.09	1.15	1.14	1.16	1.12	1.00	1.14
Fuel Ethanol Production	1.01	1.05	1.02	1.04	1.02	0.69	0.85	0.93	0.94	0.97	0.98	0.99	1.03	0.87	0.97
Petroleum Products Adjustment (f)	0.22	0.20	0.21	0.21	0.22	0.19	0.20	0.21	0.21	0.21	0.21	0.22	0.21	0.21	0.21
Product Net Imports (c)	-3.30	-3.04	-3.13	-3.43	-4.13	-3.43	-2.97	-3.67	-3.49	-3.50	-3.66	-4.10	-3.22	-3.55	-3.69
Hydrocarbon Gas Liquids	-1.33	-1.65	-1.66	-1.83	-1.99	-2.01	-1.83	-1.71	-1.56	-1.69	-1.69	-1.69	-1.62	-1.88	-1.66
Unfinished Oils	0.21	0.47	0.47	0.50	0.34	0.20	0.44	0.37	0.35	0.45	0.44	0.32	0.41	0.34	0.39
Other HC/Oxygenates	-0.08	-0.07	-0.05	-0.05	-0.12	-0.09	-0.10	-0.11	-0.14	-0.12	-0.12	-0.13	-0.06	-0.11	-0.13
Motor Gasoline Blend Comp.	0.43	0.79	0.70	0.46	0.42	0.24	0.44	0.21	0.48	0.70	0.48	0.21	0.60	0.33	0.47
Finished Motor Gasoline	-0.82	-0.63	-0.62	-0.87	-0.73	-0.01	-0.12	-0.47	-0.89	-0.90	-0.85	-0.91	-0.74	-0.33	-0.88
Jet Fuel	-0.08	-0.01	-0.05	-0.09	-0.08	0.02	-0.13	-0.05	-0.05	-0.04	0.03	0.00	-0.06	-0.06	-0.01
Distillate Fuel Oil	-0.91	-1.29	-1.30	-0.99	-1.20	-1.27	-1.15	-1.15	-1.01	-1.15	-1.21	-1.09	-1.12	-1.19	-1.12
Residual Fuel Oil	-0.08	-0.15	-0.08	-0.03	0.01	-0.01	-0.02	0.00	-0.02	-0.11	-0.06	0.00	-0.08	0.00	-0.05
Other Oils (g)	-0.64	-0.50	-0.52	-0.54	-0.78	-0.50	-0.51	-0.76	-0.66	-0.64	-0.69	-0.81	-0.55	-0.64	-0.70
Product Inventory Net Withdrawals	0.44	-0.64	-0.36	0.26	0.25	-0.56	-0.15	0.41	0.36	-0.51	-0.27	0.37	-0.07	-0.01	-0.01
Total Supply	20.38	20.31	20.67	20.57	19.35	15.87	18.67	19.26	19.18	19.61	20.19	20.18	20.48	18.29	19.79
Consumption (million barrels per day)															
Hydrocarbon Gas Liquids	3.49	2.78	2.94	3.31	3.25	2.64	2.70	3.00	3.19	2.80	2.93	3.28	3.13	2.90	3.05
Unfinished Oils	-0.03	0.09	0.04	0.10	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.02	0.00
Motor Gasoline	8.96	9.48	9.49	9.16	8.58	6.98	8.67	8.78	8.44	8.97	9.06	8.88	9.27	8.26	8.84
Fuel Ethanol blended into Motor Gasoline	0.91	0.97	0.95	0.96	0.85	0.69	0.84	0.88	0.85	0.91	0.91	0.90	0.95	0.82	0.89
Jet Fuel	1.65	1.78	1.79	1.74	1.57	0.81	1.28	1.57	1.55	1.65	1.75	1.72	1.74	1.31	1.67
Distillate Fuel Oil	4.28	4.01	3.94	4.10	3.96	3.32	3.64	3.81	3.92	3.95	3.98	4.09	4.08	3.68	3.99
Residual Fuel Oil	0.27	0.23	0.32	0.27	0.19	0.22	0.31	0.28	0.29	0.23	0.31	0.27	0.27	0.25	0.27
Other Oils (g)	1.68	1.95	2.14	1.88	1.72	1.89	2.07	1.81	1.78	2.01	2.16	1.92	1.91	1.87	1.97
Total Consumption	20.30	20.31	20.67	20.57	19.35	15.87	18.67	19.26	19.18	19.61	20.19	20.18	20.46	18.29	19.79
Total Petroleum and Other Liquids Net Imports	0.95	1.10	0.83	-0.49	-1.27	-0.88	0.26	0.51	1.01	1.66	1.90	1.19	0.59	-0.34	1.44
End-of-period Inventories (million barrels)															
Commercial Inventory															
Crude Oil (excluding SPR)	459.3	464.0	426.5	432.9	484.4	580.3	554.6	539.2	554.5	537.4	514.8	513.1	432.9	539.2	513.1
Hydrocarbon Gas Liquids	156.9	224.1	262.8	211.7	178.0	223.7	257.9	214.1	174.5	221.3	256.5	214.1	211.7	214.1	214.1
Unfinished Oils	92.0	95.9	92.2	89.4	100.2	91.5	89.7	83.6	93.6	91.4	90.9	85.1	89.4	83.6	85.1
Other HC/Oxygenates	30.8	29.0	28.4	27.8	32.9	28.4	23.7	22.7	23.1	22.1	21.4	22.0	27.8	22.7	22.0
Total Motor Gasoline	236.1	229.7	231.9	253.8	257.3	243.9	233.4	245.2	247.2	245.8	239.2	251.2	253.8	245.2	251.2
Finished Motor Gasoline	21.7	21.0	23.0	26.0	21.5	25.0	24.8	25.0	24.1	22.6	23.5	24.0	26.0	25.0	24.0
Motor Gasoline Blend Comp.	214.4	208.8	208.9	227.9	235.8	218.9	208.6	220.2	223.1	223.3	215.7	227.2	227.9	220.2	227.2
Jet Fuel	41.6	40.6	44.4	40.5	38.9	40.7	42.6	41.1	40.5	41.3	43.4	40.4	40.5	41.1	40.4
Distillate Fuel Oil	132.4	130.8	131.7	140.0	122.7	152.7	156.6	159.3	147.4	151.6	155.3	155.7	140.0	159.3	155.7
Residual Fuel Oil	28.7	30.3	29.9	30.9	36.0	35.1	31.7	30.4	32.3	33.5	31.2	32.8	30.9	30.4	32.8
Other Oils (g)	63.2	59.1	51.2	54.6	60.2	61.5	55.4	57.3	62.6	61.1	55.1	57.2	54.6	57.3	57.2
Total Commercial Inventory	1,241	1,304	1,299	1,282	1,311	1,458	1,446	1,393	1,376	1,405	1,408	1,372	1,282	1,393	1,372
Crude Oil in SPR	649	645	645	635	635	658	658	645	632	629	628	625	635	645	625

\- = no data available
(a) Includes lease condensate.
(b) Crude oil production from U.S. Federal leases in the Gulf of Mexico (GOM).
(c) Net imports equals gross imports minus gross exports.
(d) Crude oil adjustment balances supply and consumption and was previously referred to as "Unaccounted for Crude Oil."
(e) Renewables and oxygenate production includes pentanes plus, oxygenates (excluding fuel ethanol), and renewable fuels.
(f) Petroleum products adjustment includes hydrogen/oxygenates/renewables/other hydrocarbons, motor gasoline blend components, and finished motor gasoline.
(g) "Other Oils" inludes aviation gasoline blend components, finished aviation gasoline, kerosene, petrochemical feedstocks, special naphthas, lubricants, waxes, petroleum coke, asphalt and road oil, still gas, and miscellaneous products.
Notes: The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.
SPR: Strategic Petroleum Reserve
HC: Hydrocarbons
Historical data: Latest data available from Energy Information Administration databases supporting the following reports: *Petroleum Supply Monthly* , DOE/EIA-0109; *Petroleum Supply Annual* , DOE/EIA-0340/2; and *Weekly Petroleum Status Report* , DOE/EIA-0208.
Minor discrepancies with published historical data are due to independent rounding.
Projections: EIA Regional Short-Term Energy Model.

Table 4b. U.S. Hydrocarbon Gas Liquids (HGL) and Petroleum Refinery Balances (million barrels per day, except inventories and utilization factor)

U.S. Energy Information Administration | Short-Term Energy Outlook - May 2020

	2019				2020				2021				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2019	2020	2021
HGL Production															
Natural Gas Processing Plants															
Ethane	1.87	1.87	1.71	1.85	1.92	1.79	1.70	1.75	1.76	1.90	1.92	2.00	1.83	1.79	1.89
Propane	1.50	1.56	1.61	1.67	1.69	1.59	1.54	1.49	1.43	1.45	1.49	1.50	1.59	1.58	1.47
Butanes	0.79	0.84	0.87	0.89	0.89	0.85	0.83	0.80	0.75	0.78	0.80	0.81	0.85	0.84	0.79
Natural Gasoline (Pentanes Plus)	0.49	0.55	0.60	0.57	0.55	0.55	0.56	0.52	0.48	0.52	0.55	0.52	0.55	0.55	0.52
Refinery and Blender Net Production															
Ethane/Ethylene	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.01	0.00	0.01	0.01	0.01	0.01	0.00	0.01
Propane	0.28	0.30	0.29	0.29	0.28	0.25	0.28	0.29	0.28	0.30	0.30	0.30	0.29	0.27	0.29
Propylene (refinery-grade)	0.28	0.28	0.28	0.28	0.26	0.24	0.26	0.28	0.28	0.29	0.28	0.29	0.28	0.26	0.29
Butanes/Butylenes	-0.09	0.26	0.18	-0.23	-0.08	0.26	0.18	-0.20	-0.09	0.26	0.18	-0.20	0.03	0.04	0.04
Renewable Fuels and Oxygenate Plant Net Production															
Natural Gasoline (Pentanes Plus)	-0.02	-0.02	-0.02	-0.02	-0.02	-0.01	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02
HGL Net Imports															
Ethane	-0.27	-0.27	-0.28	-0.31	-0.30	-0.27	-0.28	-0.30	-0.27	-0.29	-0.30	-0.29	-0.28	-0.29	-0.29
Propane/Propylene	-0.75	-0.99	-0.97	-1.07	-1.08	-1.10	-0.97	-1.01	-0.87	-0.92	-0.88	-0.96	-0.94	-1.04	-0.91
Butanes/Butylenes	-0.14	-0.26	-0.26	-0.25	-0.31	-0.42	-0.35	-0.21	-0.19	-0.25	-0.27	-0.21	-0.23	-0.32	-0.23
Natural Gasoline (Pentanes Plus)	-0.17	-0.14	-0.15	-0.21	-0.30	-0.22	-0.23	-0.18	-0.22	-0.22	-0.24	-0.23	-0.17	-0.23	-0.23
HGL Refinery and Blender Net Inputs															
Butanes/Butylenes	0.46	0.29	0.33	0.54	0.45	0.16	0.25	0.48	0.39	0.29	0.32	0.51	0.40	0.34	0.38
Natural Gasoline (Pentanes Plus)	0.14	0.17	0.18	0.18	0.16	0.20	0.19	0.19	0.17	0.18	0.19	0.18	0.17	0.19	0.18
HGL Consumption															
Ethane/Ethylene	1.61	1.49	1.47	1.55	1.67	1.46	1.44	1.44	1.50	1.58	1.65	1.72	1.53	1.50	1.61
Propane	1.20	0.58	0.65	1.05	1.08	0.59	0.65	0.91	1.10	0.60	0.69	0.96	0.87	0.81	0.84
Propylene (refinery-grade)	0.29	0.30	0.29	0.31	0.27	0.25	0.27	0.29	0.30	0.30	0.30	0.30	0.30	0.27	0.30
Butanes/Butylenes	0.20	0.21	0.30	0.24	0.17	0.24	0.22	0.23	0.20	0.23	0.21	0.21	0.24	0.21	0.21
Natural Gasoline (Pentanes Plus)	0.20	0.20	0.23	0.17	0.06	0.11	0.12	0.13	0.09	0.08	0.09	0.10	0.20	0.10	0.09
HGL Inventories (million barrels)															
Ethane	48.14	56.18	56.46	58.84	53.29	58.66	58.12	59.88	57.62	60.69	59.22	60.32	54.94	57.50	59.47
Propane	46.49	70.49	93.75	78.55	60.76	73.80	90.87	76.64	50.68	69.09	87.82	75.39	78.55	76.64	75.39
Propylene (refinery-grade)	1.68	1.76	2.65	1.66	1.57	2.14	2.67	3.19	3.17	3.64	4.08	4.48	1.66	3.19	4.48
Butanes/Butylenes	42.48	66.68	84.01	48.99	40.78	67.31	84.78	55.15	44.97	69.09	86.55	56.93	48.99	55.15	56.93
Natural Gasoline (Pentanes Plus)	18.12	19.71	21.28	20.90	21.20	22.41	23.35	22.65	20.10	21.35	22.36	21.78	20.90	22.65	21.78
Refinery and Blender Net Inputs															
Crude OIl	16.20	16.76	16.97	16.32	15.78	13.13	14.95	15.58	15.50	16.48	16.87	16.56	16.56	14.86	16.36
Hydrocarbon Gas Liquids	0.59	0.46	0.51	0.72	0.61	0.36	0.44	0.67	0.57	0.47	0.51	0.69	0.57	0.52	0.56
Other Hydrocarbons/Oxygenates	1.16	1.21	1.22	1.19	1.12	0.91	1.06	1.10	1.10	1.17	1.16	1.16	1.19	1.05	1.15
Unfinished Oils	0.18	0.34	0.46	0.43	0.13	0.29	0.46	0.43	0.24	0.47	0.45	0.38	0.35	0.33	0.39
Motor Gasoline Blend Components	0.63	0.94	0.77	0.40	0.37	0.49	0.66	0.26	0.57	0.84	0.66	0.26	0.68	0.45	0.58
Aviation Gasoline Blend Components	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Refinery and Blender Net Inputs	18.76	19.70	19.93	19.07	18.02	15.19	17.58	18.04	17.98	19.44	19.65	19.05	19.37	17.21	19.03
Refinery Processing Gain	1.06	1.07	1.07	1.10	1.07	0.93	1.01	1.10	1.09	1.14	1.13	1.13	1.08	1.03	1.12
Refinery and Blender Net Production															
Hydrocarbon Gas Liquids	0.48	0.84	0.76	0.34	0.46	0.76	0.73	0.37	0.48	0.85	0.77	0.39	0.61	0.58	0.62
Finished Motor Gasoline	9.84	10.15	10.20	10.16	9.29	7.07	8.85	9.40	9.41	9.96	9.99	9.93	10.09	8.65	9.82
Jet Fuel	1.73	1.78	1.88	1.79	1.63	0.81	1.43	1.60	1.59	1.70	1.74	1.69	1.80	1.37	1.68
Distillate Fuel	5.05	5.21	5.18	5.11	4.91	4.85	4.76	4.92	4.77	5.08	5.16	5.12	5.14	4.86	5.03
Residual Fuel	0.36	0.39	0.39	0.31	0.24	0.22	0.29	0.26	0.32	0.35	0.34	0.30	0.36	0.25	0.33
Other Oils (a)	2.37	2.40	2.58	2.46	2.57	2.40	2.52	2.59	2.50	2.63	2.78	2.76	2.45	2.52	2.67
Total Refinery and Blender Net Production	19.82	20.78	21.00	20.17	19.09	16.12	18.59	19.14	19.07	20.58	20.78	20.18	20.44	18.24	20.16
Refinery Distillation Inputs	16.48	17.14	17.44	16.86	16.36	13.66	15.44	15.93	15.83	16.71	17.12	16.80	16.98	15.35	16.62
Refinery Operable Distillation Capacity	18.78	18.80	18.81	18.81	18.98	18.98	18.98	19.00	19.00	19.00	19.00	19.03	18.80	18.98	19.01
Refinery Distillation Utilization Factor	0.88	0.91	0.93	0.90	0.86	0.72	0.81	0.84	0.83	0.88	0.90	0.88	0.90	0.81	0.87

\- = no data available

(a) "Other Oils" includes aviation gasoline blend components, finished aviation gasoline, kerosene, petrochemical feedstocks, special naphthas, lubricants, waxes, petroleum coke, asphalt and road oil, still gas, and miscellaneous products.

Notes: The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Historical data: Latest data available from Energy Information Administration databases supporting the following reports: *Petroleum Supply Monthly* , DOE/EIA-0109; *Petroleum Supply Annual* , DOE/EIA-0340/2; *Weekly Petroleum Status Report* , DOE/EIA-0208.

Minor discrepancies with published historical data are due to independent rounding.

Projections: EIA Regional Short-Term Energy Model.

Table 4c. U.S. Regional Motor Gasoline Prices and Inventories
U.S. Energy Information Administration | Short-Term Energy Outlook - May 2020

	2019				2020				2021				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2019	2020	2021
Prices (cents per gallon)															
Refiner Wholesale Price	**167**	**205**	**189**	**182**	**148**	*83*	*105*	*107*	*120*	*151*	*154*	*148*	**186**	*112*	*144*
Gasoline Regular Grade Retail Prices Including Taxes															
PADD 1	**233**	**268**	**256**	**247**	**236**	*189*	*178*	*172*	*184*	*216*	*222*	*216*	**251**	*194*	*210*
PADD 2	**223**	**269**	**257**	**244**	**226**	*169*	*175*	*170*	*176*	*220*	*221*	*210*	**249**	*185*	*208*
PADD 3	**206**	**246**	**234**	**224**	**210**	*162*	*160*	*155*	*167*	*198*	*202*	*194*	**228**	*172*	*191*
PADD 4	**226**	**285**	**270**	**276**	**246**	*188*	*181*	*174*	*183*	*218*	*227*	*216*	**265**	*198*	*212*
PADD 5	**297**	**356**	**331**	**350**	**311**	*261*	*253*	*245*	*243*	*283*	*287*	*280*	**334**	*268*	*274*
U.S. Average	**236**	**279**	**265**	**259**	**241**	*191*	*187*	*181*	*189*	*226*	*230*	*222*	**260**	*200*	*217*
Gasoline All Grades Including Taxes	**245**	**288**	**274**	**269**	**250**	*202*	*199*	*194*	*202*	*239*	*243*	*235*	**269**	*212*	*231*
End-of-period Inventories (million barrels)															
Total Gasoline Inventories															
PADD 1	**62.4**	**59.7**	**64.9**	**65.6**	**70.5**	*64.7*	*59.0*	*62.3*	*66.6*	*68.4*	*62.7*	*67.6*	**65.6**	*62.3*	*67.6*
PADD 2	**53.9**	**49.6**	**51.0**	**55.0**	**60.5**	*51.9*	*49.7*	*51.5*	*54.2*	*53.4*	*52.8*	*50.4*	**55.0**	*51.5*	*50.4*
PADD 3	**82.5**	**82.4**	**81.5**	**91.8**	**81.9**	*89.5*	*88.2*	*92.1*	*88.3*	*87.0*	*86.8*	*93.2*	**91.8**	*92.1*	*93.2*
PADD 4	**6.9**	**7.5**	**7.7**	**8.3**	**9.4**	*7.7*	*6.9*	*7.2*	*7.6*	*7.9*	*7.5*	*7.9*	**8.3**	*7.2*	*7.9*
PADD 5	**30.4**	**30.6**	**26.8**	**33.2**	**34.9**	*30.1*	*29.6*	*32.0*	*30.4*	*29.2*	*29.4*	*32.1*	**33.2**	*32.0*	*32.1*
U.S. Total	**236.1**	**229.7**	**231.9**	**253.8**	**257.3**	*243.9*	*233.4*	*245.2*	*247.2*	*245.8*	*239.2*	*251.2*	**253.8**	*245.2*	*251.2*
Finished Gasoline Inventories															
U.S. Total	**21.7**	**21.0**	**23.0**	**26.0**	**21.5**	*25.0*	*24.8*	*25.0*	*24.1*	*22.6*	*23.5*	*24.0*	**26.0**	*25.0*	*24.0*
Gasoline Blending Components Inventories															
U.S. Total	**214.4**	**208.8**	**208.9**	**227.9**	**235.8**	*218.9*	*208.6*	*220.2*	*223.1*	*223.3*	*215.7*	*227.2*	**227.9**	*220.2*	*227.2*

- = no data available
Prices are not adjusted for inflation.
Notes: The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.
Regions refer to Petroleum Administration for Defense Districts (PADD).
See "Petroleum for Administration Defense District" in EIA's Energy Glossary (http://www.eia.doe.gov/glossary/index.html) for a list of States in each region.
Historical data: Latest data available from Energy Information Administration databases supporting the following reports: *Petroleum Marketing Monthly* , DOE/EIA-0380; *Petroleum Supply Monthly* , DOE/EIA-0109; *Petroleum Supply Annual* , DOE/EIA-0340/2; and *Weekly Petroleum Status Report* , DOE/EIA-0208.
Minor discrepancies with published historical data are due to independent rounding.
Projections: EIA Regional Short-Term Energy Model.

Table 5a. U.S. Natural Gas Supply, Consumption, and Inventories
U.S. Energy Information Administration | Short-Term Energy Outlook - May 2020

	2019				2020				2021				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2019	2020	2021
Supply (billion cubic feet per day)															
Total Marketed Production	96.08	97.44	99.91	103.16	101.79	98.38	95.14	93.05	91.11	91.04	92.11	93.46	99.17	97.07	91.94
Alaska	0.96	0.93	0.79	0.93	0.98	0.81	0.77	0.94	1.00	0.87	0.80	0.95	0.90	0.87	0.90
Federal GOM (a)	2.80	2.75	2.51	2.72	2.73	2.44	2.47	2.41	2.43	2.34	2.20	2.16	2.69	2.51	2.28
Lower 48 States (excl GOM)	92.32	93.76	96.61	99.51	98.08	95.13	91.90	89.71	87.69	87.83	89.11	90.35	95.57	93.69	88.75
Total Dry Gas Production	89.32	90.50	92.98	95.97	94.28	91.08	88.03	86.05	84.21	84.09	85.03	86.22	92.21	89.84	84.89
LNG Gross Imports	0.28	0.03	0.06	0.20	0.26	0.10	0.18	0.20	0.32	0.18	0.18	0.20	0.14	0.18	0.22
LNG Gross Exports	4.01	4.55	4.95	6.40	7.92	5.84	4.82	5.58	7.07	6.42	7.56	8.20	4.98	6.04	7.31
Pipeline Gross Imports	8.35	6.73	7.10	7.30	7.92	6.87	6.94	7.46	8.46	7.50	7.68	8.06	7.37	7.30	7.92
Pipeline Gross Exports	7.86	7.18	7.80	8.25	8.12	7.53	8.20	8.53	8.76	7.90	8.71	8.84	7.77	8.09	8.55
Supplemental Gaseous Fuels	0.20	0.16	0.15	0.17	0.19	0.17	0.16	0.16	0.15	0.15	0.15	0.16	0.17	0.17	0.15
Net Inventory Withdrawals	16.93	-14.18	-10.41	2.44	12.71	-12.15	-8.16	3.29	17.32	-8.57	-7.31	3.97	-1.37	-1.08	1.29
Total Supply	103.21	71.52	77.14	91.43	99.31	72.70	74.13	83.04	94.63	69.03	69.47	81.58	85.77	82.28	78.62
Balancing Item (b)	0.11	-0.79	-0.39	-2.10	0.73	-1.10	-1.21	-0.77	-0.43	-0.17	1.29	1.49	-0.80	-0.59	0.55
Total Primary Supply	103.32	70.74	76.74	89.33	100.04	71.60	72.92	82.27	94.20	68.86	70.76	83.07	84.97	81.69	79.17
Consumption (billion cubic feet per day)															
Residential	27.15	7.34	3.53	17.00	23.55	8.64	3.94	16.87	25.12	7.86	3.68	16.57	13.70	13.23	13.26
Commercial	16.19	6.36	4.68	11.45	14.17	6.40	4.66	10.78	15.38	6.50	4.69	10.49	9.65	9.00	9.24
Industrial	25.12	21.74	21.31	23.79	24.65	20.42	18.89	21.45	22.36	20.39	19.87	22.91	22.98	21.35	21.38
Electric Power (c)	26.83	28.13	39.74	29.09	29.36	28.83	38.41	25.96	23.79	27.12	35.28	25.47	30.98	30.65	27.94
Lease and Plant Fuel	4.93	5.00	5.13	5.29	5.22	5.05	4.88	4.77	4.68	4.67	4.73	4.80	5.09	4.98	4.72
Pipeline and Distribution Use	2.96	2.03	2.20	2.56	2.93	2.10	1.98	2.27	2.71	2.14	2.34	2.67	2.44	2.32	2.47
Vehicle Use	0.13	0.13	0.14	0.15	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.14	0.16	0.16
Total Consumption	103.32	70.74	76.74	89.33	100.04	71.60	72.92	82.27	94.20	68.86	70.76	83.07	84.97	81.69	79.17
End-of-period Inventories (billion cubic feet)															
Working Gas Inventory	1,185	2,461	3,415	3,189	2,033	3,138	3,889	3,586	2,027	2,807	3,480	3,114	3,189	3,586	3,114
East Region (d)	216	537	845	764	382	670	951	834	355	587	821	659	764	834	659
Midwest Region (d)	242	579	990	885	475	761	1,097	991	435	621	933	806	885	991	806
South Central Region (d)	519	917	1,049	1,095	858	1,231	1,290	1,278	892	1,119	1,181	1,184	1,095	1,278	1,184
Mountain Region (d)	63	135	200	167	92	160	207	171	119	159	199	163	167	171	163
Pacific Region (d)	115	259	294	245	200	291	318	288	201	297	320	277	245	288	277
Alaska	30	33	37	33	24	25	25	25	25	25	25	25	33	25	25

- = no data available

(a) Marketed production from U.S. Federal leases in the Gulf of Mexico.

(b) The balancing item represents the difference between the sum of the components of natural gas supply and the sum of components of natural gas demand.

(c) Natural gas used for electricity generation and (a limited amount of) useful thermal output by electric utilities and independent power producers.

(d) For a list of States in each inventory region refer to *Weekly Natural Gas Storage Report, Notes and Definitions (http://ir.eia.gov/ngs/notes.html)* .

Notes: The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

LNG: liquefied natural gas.

Historical data: Latest data available from Energy Information Administration databases supporting the following reports: *Natural Gas Monthly* , DOE/EIA-0130; and *Electric Power Monthly* , DOE/EIA-0226.

Minor discrepancies with published historical data are due to independent rounding.

Projections: EIA Regional Short-Term Energy Model.

Table 5b. U.S. Regional Natural Gas Prices (dollars per thousand cubic feet)

U.S. Energy Information Administration | Short-Term Energy Outlook - May 2020

	2019				2020				2021				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2019	2020	2021
Wholesale/Spot															
Henry Hub Spot Price	**3.03**	**2.66**	**2.47**	**2.49**	**1.96**	*1.92*	*2.19*	*2.81*	*3.11*	*2.85*	*2.94*	*3.09*	**2.66**	*2.22*	*3.00*
Residential Retail															
New England	**14.44**	**15.56**	**19.31**	**14.05**	**13.69**	*13.89*	*16.57*	*12.75*	*12.69*	*13.90*	*16.91*	*13.06*	**14.78**	*13.61*	*13.26*
Middle Atlantic	**10.79**	**13.08**	**18.50**	**11.38**	**10.78**	*12.15*	*16.01*	*10.16*	*9.44*	*11.91*	*16.55*	*10.89*	**11.74**	*11.11*	*10.66*
E. N. Central	**7.27**	**10.48**	**19.03**	**7.68**	**6.96**	*9.54*	*15.72*	*7.90*	*7.56*	*10.68*	*16.44*	*8.24*	**8.41**	*8.09*	*8.73*
W. N. Central	**7.93**	**10.67**	**18.16**	**8.16**	**7.31**	*9.92*	*16.20*	*8.48*	*7.69*	*10.81*	*16.94*	*9.00*	**8.81**	*8.48*	*9.00*
S. Atlantic	**11.63**	**18.34**	**26.03**	**12.90**	**12.01**	*15.95*	*21.83*	*11.91*	*10.84*	*16.19*	*22.36*	*12.43*	**13.83**	*13.27*	*12.87*
E. S. Central	**9.64**	**14.84**	**21.40**	**10.43**	**9.68**	*13.81*	*20.83*	*12.68*	*10.56*	*15.34*	*22.09*	*13.51*	**11.05**	*11.58*	*12.69*
W. S. Central	**8.29**	**13.38**	**21.45**	**10.54**	**8.65**	*13.85*	*20.04*	*11.86*	*9.54*	*15.11*	*20.69*	*12.12*	**10.54**	*11.40*	*11.97*
Mountain	**7.73**	**9.46**	**13.40**	**7.75**	**7.48**	*8.93*	*12.70*	*7.76*	*7.79*	*9.76*	*13.58*	*8.50*	**8.37**	*8.15*	*8.77*
Pacific	**12.44**	**12.75**	**13.50**	**12.06**	**13.48**	*13.32*	*13.65*	*12.61*	*13.07*	*13.92*	*14.65*	*13.59*	**12.50**	*13.21*	*13.57*
U.S. Average	**9.47**	**12.48**	**18.10**	**9.88**	**9.48**	*11.65*	*16.37*	*10.01*	*9.38*	*12.34*	*17.10*	*10.59*	**10.56**	*10.52*	*10.74*
Commercial Retail															
New England	**11.21**	**11.42**	**11.61**	**10.13**	**10.32**	*9.48*	*8.67*	*8.60*	*9.00*	*9.23*	*9.51*	*9.75*	**10.95**	*9.61*	*9.36*
Middle Atlantic	**8.43**	**7.72**	**6.86**	**7.47**	**7.88**	*7.28*	*6.59*	*7.27*	*7.60*	*7.55*	*7.00*	*7.52*	**7.85**	*7.43*	*7.49*
E. N. Central	**6.27**	**7.19**	**8.85**	**6.04**	**5.74**	*6.54*	*8.10*	*6.37*	*6.44*	*7.59*	*8.94*	*6.93*	**6.51**	*6.23*	*6.95*
W. N. Central	**6.79**	**7.11**	**8.20**	**6.16**	**6.07**	*6.35*	*7.72*	*6.53*	*7.00*	*7.51*	*8.70*	*7.21*	**6.73**	*6.37*	*7.27*
S. Atlantic	**8.85**	**9.54**	**9.64**	**8.82**	**8.47**	*8.94*	*9.51*	*8.88*	*9.01*	*9.87*	*10.05*	*8.91*	**9.05**	*8.80*	*9.25*
E. S. Central	**8.61**	**9.78**	**10.06**	**8.54**	**8.30**	*8.53*	*8.89*	*8.05*	*7.92*	*9.10*	*9.71*	*8.76*	**8.91**	*8.32*	*8.56*
W. S. Central	**6.02**	**6.57**	**7.42**	**6.38**	**5.69**	*6.24*	*7.12*	*6.91*	*6.90*	*7.45*	*8.08*	*7.54*	**6.41**	*6.29*	*7.35*
Mountain	**6.40**	**6.72**	**7.41**	**6.16**	**6.06**	*6.26*	*7.18*	*6.40*	*6.82*	*7.23*	*8.09*	*7.17*	**6.47**	*6.31*	*7.14*
Pacific	**9.08**	**8.82**	**9.14**	**8.90**	**9.45**	*8.53*	*8.42*	*8.16*	*8.56*	*8.73*	*9.02*	*8.71*	**8.99**	*8.72*	*8.71*
U.S. Average	**7.59**	**7.97**	**8.40**	**7.22**	**7.18**	*7.34*	*7.81*	*7.24*	*7.43*	*8.04*	*8.51*	*7.77*	**7.62**	*7.29*	*7.75*
Industrial Retail															
New England	**9.17**	**8.27**	**6.92**	**7.29**	**8.01**	*7.11*	*6.58*	*7.89*	*8.63*	*7.93*	*7.15*	*7.97*	**8.08**	*7.53*	*8.03*
Middle Atlantic	**8.76**	**7.65**	**6.99**	**6.95**	**7.36**	*6.55*	*6.48*	*6.97*	*7.63*	*7.14*	*7.21*	*7.48*	**7.86**	*7.00*	*7.45*
E. N. Central	**5.75**	**5.38**	**5.64**	**5.14**	**4.93**	*4.62*	*4.73*	*5.07*	*5.95*	*5.72*	*5.74*	*5.80*	**5.49**	*4.90*	*5.84*
W. N. Central	**5.16**	**3.94**	**3.37**	**4.19**	**3.96**	*3.19*	*3.24*	*4.32*	*5.05*	*4.31*	*4.28*	*5.04*	**4.24**	*3.75*	*4.73*
S. Atlantic	**5.52**	**4.60**	**4.40**	**4.52**	**4.16**	*3.81*	*4.04*	*4.81*	*5.40*	*4.80*	*4.75*	*5.08*	**4.80**	*4.22*	*5.03*
E. S. Central	**4.93**	**4.04**	**3.59**	**4.07**	**3.88**	*3.52*	*3.74*	*4.57*	*5.04*	*4.54*	*4.45*	*4.88*	**4.20**	*3.94*	*4.75*
W. S. Central	**3.47**	**2.88**	**2.53**	**2.64**	**2.19**	*1.95*	*2.31*	*2.92*	*3.26*	*2.97*	*3.15*	*3.29*	**2.89**	*2.35*	*3.17*
Mountain	**5.31**	**4.80**	**5.00**	**4.72**	**4.45**	*4.34*	*4.76*	*5.08*	*5.48*	*5.29*	*5.62*	*5.73*	**4.96**	*4.66*	*5.54*
Pacific	**7.68**	**6.66**	**6.49**	**6.83**	**7.43**	*5.89*	*5.76*	*6.01*	*6.79*	*6.37*	*6.51*	*6.61*	**6.97**	*6.35*	*6.58*
U.S. Average	**4.67**	**3.74**	**3.30**	**3.74**	**3.48**	*2.74*	*2.91*	*3.74*	*4.32*	*3.74*	*3.77*	*4.22*	**3.91**	*3.24*	*4.03*

- = no data available

Prices are not adjusted for inflation.

Notes: The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Regions refer to U.S. Census divisions.

See "Census division" in EIA's Energy Glossary (http://www.eia.doe.gov/glossary/index.html) for a list of States in each region.

Historical data: Latest data available from Energy Information Administration databases supporting the *Natural Gas Monthly* , DOE/EIA-0130.

Natural gas Henry Hub spot price from Reuter's News Service (http://www.reuters.com).

Minor discrepancies with published historical data are due to independent rounding.

Projections: EIA Regional Short-Term Energy Model.

Table 6. U.S. Coal Supply, Consumption, and Inventories

U.S. Energy Information Administration | Short-Term Energy Outlook - May 2020

	2019				2020				2021				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2019	2020	2021
Supply (million short tons)															
Production	170.3	174.9	179.7	165.2	149.8	114.5	129.9	128.5	142.4	118.8	150.1	138.4	690.1	522.6	549.6
Appalachia	47.4	49.3	46.6	44.3	42.6	29.2	28.2	25.9	28.4	27.2	31.4	27.9	187.6	125.9	114.9
Interior	31.0	32.2	32.4	30.6	28.3	22.0	29.0	31.8	35.8	28.8	32.1	32.3	126.2	111.1	129.1
Western	91.9	93.4	102.4	90.3	78.8	62.5	72.7	70.8	78.2	62.7	86.6	78.2	378.0	284.9	305.7
Primary Inventory Withdrawals	-1.5	1.3	-1.2	-1.4	-0.2	1.4	2.1	-1.9	-0.1	1.1	1.8	-2.0	-2.7	1.4	0.7
Imports	1.7	1.6	1.7	1.7	1.3	1.4	1.5	1.4	1.2	1.3	1.5	1.4	6.7	5.7	5.4
Exports	25.2	25.3	21.9	20.4	20.0	16.2	14.0	13.0	22.4	18.0	15.6	14.5	92.9	63.2	70.5
Metallurgical Coal	13.9	15.1	13.5	12.6	11.7	9.3	8.1	7.5	13.0	10.5	9.1	8.5	55.1	36.6	41.1
Steam Coal	11.3	10.2	8.4	7.8	8.3	6.9	5.9	5.5	9.3	7.5	6.5	6.0	37.7	26.6	29.4
Total Primary Supply	145.3	152.4	158.3	145.2	130.9	101.0	119.5	115.1	121.2	103.0	137.8	123.2	601.2	466.6	485.2
Secondary Inventory Withdrawals	6.2	-21.0	6.4	-17.5	-20.9	5.0	8.7	-7.2	-0.4	4.4	8.5	-7.5	-26.0	-14.5	5.1
Waste Coal (a)	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.0	2.0	2.0	2.0	9.3	9.2	8.0
Total Supply	153.8	133.7	167.0	130.0	112.3	108.2	130.6	110.1	122.7	109.5	148.3	117.8	584.6	461.2	498.3
Consumption (million short tons)															
Coke Plants	4.5	4.7	4.5	4.3	4.9	3.4	3.4	5.4	4.6	4.5	4.4	5.5	17.9	17.0	19.1
Electric Power Sector (b)	145.3	118.0	156.2	119.9	101.3	89.1	121.3	98.8	112.1	99.0	138.0	105.9	539.4	410.5	455.0
Retail and Other Industry	8.1	7.2	7.2	7.5	7.6	6.5	5.9	6.0	6.1	5.9	5.9	6.3	30.0	26.0	24.2
Residential and Commercial	0.3	0.2	0.2	0.2	0.2	0.2	0.3	0.4	0.3	0.2	0.2	0.3	0.9	1.0	1.0
Other Industrial	7.8	7.0	7.0	7.3	7.4	6.3	5.6	5.6	5.7	5.7	5.7	6.0	29.1	25.0	23.2
Total Consumption	157.9	129.9	167.8	131.8	113.8	99.0	130.6	110.1	122.7	109.5	148.3	117.8	587.3	453.5	498.3
Discrepancy (c)	-4.0	3.9	-0.8	-1.8	-1.5	9.3	0.0	0.0	0.0	0.0	0.0	0.0	-2.8	7.7	0.0
End-of-period Inventories (million short tons)															
Primary Inventories (d)	23.2	21.9	23.1	24.4	24.6	23.3	21.2	23.0	23.1	22.0	20.3	22.3	24.4	23.0	22.3
Secondary Inventories	102.2	123.2	116.8	134.3	155.3	150.3	141.6	148.8	149.2	144.8	136.3	143.8	134.3	148.8	143.8
Electric Power Sector	97.1	117.7	111.0	128.5	149.7	144.5	135.7	143.2	143.8	139.1	130.4	138.1	128.5	143.2	138.1
Retail and General Industry	2.8	3.0	3.2	3.3	3.7	3.6	3.6	3.5	3.7	3.7	3.7	3.5	3.3	3.5	3.5
Coke Plants	2.0	2.3	2.5	2.3	1.7	2.0	2.0	2.0	1.5	1.9	2.0	2.0	2.3	2.0	2.0
Coal Market Indicators															
Coal Miner Productivity															
(Tons per hour)	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.32	6.32	6.32	6.32	6.37	6.37	6.32
Total Raw Steel Production															
(Million short tons per day)	0.273	0.271	0.264	0.265	0.268	0.179	0.227	0.265	0.263	0.255	0.251	0.253	0.268	0.235	0.256
Cost of Coal to Electric Utilities															
(Dollars per million Btu)	2.08	2.05	2.00	1.95	1.97	2.02	1.98	1.99	2.02	2.05	2.03	2.04	2.02	1.99	2.04

- = no data available

(a) Waste coal includes waste coal and cloal slurry reprocessed into briquettes.

(b) Coal used for electricity generation and (a limited amount of) useful thermal output by electric utilities and independent power producers.

(c) The discrepancy reflects an unaccounted-for shipper and receiver reporting difference, assumed to be zero in the forecast period.

(d) Primary stocks are held at the mines and distribution points.

Notes: The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Historical data: Latest data available from Energy Information Administration databases supporting the following reports: *Quarterly Coal Report* , DOE/EIA-0121; and *Electric Power Monthly* , DOE/EIA-0226.

Minor discrepancies with published historical data are due to independent rounding.

Projections: EIA Regional Short-Term Energy Model.

Table 7a. U.S. Electricity Industry Overview

U.S. Energy Information Administration | Short-Term Energy Outlook - May 2020

	2019				2020				2021				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2019	2020	2021
Electricity Supply (billion kilowatthours)															
Electricity Generation	995	974	1,173	976	963	928	1,097	911	928	947	1,115	931	4,118	3,899	3,920
Electric Power Sector (a)	955	935	1,131	934	925	899	1,068	884	899	918	1,084	901	3,956	3,775	3,801
Industrial Sector (b)	37	36	38	38	35	27	26	25	26	26	28	28	149	114	109
Commercial Sector (b)	3	3	4	3	3	2	3	2	2	2	3	2	14	11	10
Net Imports	9	9	11	10	12	13	15	11	12	13	15	11	39	50	51
Total Supply	1,004	983	1,184	986	975	940	1,111	922	940	959	1,129	942	4,157	3,949	3,971
Losses and Unaccounted for (c)	57	71	74	59	53	63	65	52	43	66	57	53	262	233	218
Electricity Consumption (billion kilowatthours unless noted)															
Retail Sales	911	877	1072	889	885	844	1013	839	864	861	1037	855	3750	3581	3618
Residential Sector	361	309	434	331	344	322	430	321	356	321	431	320	1435	1416	1428
Commercial Sector	320	328	382	325	313	300	349	305	299	320	369	316	1355	1267	1304
Industrial Sector	228	238	254	232	227	220	232	211	207	218	236	217	952	890	878
Transportation Sector	2	2	2	2	2	2	2	2	2	2	2	2	8	8	8
Direct Use (d)	36	35	38	37	37	33	33	32	33	33	35	34	146	135	135
Total Consumption	948	912	1110	927	922	877	1046	871	897	894	1073	890	3896	3716	3753
Average residential electricity usage per customer (kWh)	2,677	2,290	3,213	2,450	2,525	2,364	3,154	2,357	2,596	2,342	3,143	2,338	10,631	10,400	10,420
Prices															
Power Generation Fuel Costs (dollars per million Btu)															
Coal	2.08	2.05	2.00	1.95	1.97	2.02	1.98	1.99	2.02	2.05	2.03	2.04	2.02	1.99	2.04
Natural Gas	3.71	2.73	2.51	2.78	2.37	1.94	2.08	2.98	3.53	2.93	2.96	3.32	2.88	2.31	3.15
Residual Fuel Oil	12.21	13.39	12.79	12.52	12.20	7.37	6.13	6.53	7.46	9.44	9.47	9.75	12.72	7.91	8.82
Distillate Fuel Oil	14.83	15.77	15.01	15.10	13.05	8.06	8.56	9.37	10.10	11.80	12.38	13.05	15.16	9.77	11.83
Retail Prices (cents per kilowatthour)															
Residential Sector	12.68	13.33	13.27	12.85	12.85	13.24	13.22	12.91	12.92	13.64	13.68	13.38	13.04	13.06	13.41
Commercial Sector	10.43	10.64	11.00	10.53	10.29	10.47	10.86	10.50	10.39	10.72	11.21	10.84	10.66	10.54	10.81
Industrial Sector	6.66	6.71	7.25	6.66	6.41	6.62	7.28	6.81	6.71	6.88	7.52	6.90	6.83	6.78	7.02
Wholesale Electricity Prices (dollars per megawatthour)															
ERCOT North hub	28.41	28.34	139.81	28.40	23.41	28.40	32.51	29.79	30.12	30.75	34.31	31.53	56.24	28.53	31.68
CAISO SP15 zone	50.42	23.30	37.32	41.57	28.64	22.18	24.63	29.72	31.30	27.99	30.02	31.75	38.15	26.29	30.26
ISO-NE Internal hub	47.40	27.15	29.52	35.48	24.61	21.75	21.48	31.48	42.23	24.60	26.81	35.32	34.89	24.83	32.24
NYISO Hudson Valley zone	41.77	25.68	27.76	27.04	21.82	20.46	20.86	22.64	24.62	23.51	25.38	24.71	30.56	21.45	24.55
PJM Western hub	33.79	28.54	31.17	29.89	22.47	24.94	29.25	26.79	28.34	28.27	31.24	28.23	30.85	25.86	29.02
Midcontinent ISO Illinois hub	31.44	27.81	30.71	28.09	24.43	25.54	29.64	27.27	27.21	28.28	31.09	27.74	29.51	26.72	28.58
SPP ISO South hub	29.15	27.14	31.51	23.64	20.06	21.96	26.93	23.97	22.76	24.23	28.36	24.19	27.86	23.23	24.89
SERC index, Into Southern	30.74	29.87	31.08	29.31	23.58	26.71	32.36	29.74	29.82	30.78	33.84	30.61	30.25	28.10	31.26
FRCC index, Florida Reliability	30.71	29.57	30.64	29.47	26.24	26.21	27.52	29.99	30.04	29.53	30.80	32.02	30.10	27.49	30.60
Northwest index, Mid-Columbia	55.74	18.55	32.74	37.47	22.77	17.29	20.46	23.34	25.01	21.38	24.09	25.75	36.12	20.97	24.06
Southwest index, Palo Verde	44.23	18.45	42.00	36.37	22.07	21.14	22.86	25.07	27.07	26.16	27.43	26.55	35.26	22.79	26.80

Notes: The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

kWh = kilowatthours. Btu = British thermal units.

Prices are not adjusted for inflation.

(a) Generation supplied by power plants with capacity of at least 1 megawatt operated by electric utilities and independent power producers.

(b) Generation supplied by power plants with capacity of at least 1 megawatt operated by businesses in the commercial and industrial sectors, primarily for onsite use.

(c) Includes transmission and distribution losses, data collection time-frame differences, and estimation error.

(d) Direct Use represents commercial and industrial facility use of onsite net electricity generation; and electrical sales or transfers to adjacent or colocated facilities for which revenue information is not available. See Table 7.6 of the EIA *Monthly Energy Review* .

Historical data sources:

(1) Electricity supply, consumption, fuel costs, and retail electricity prices: Latest data available from U.S. Energy Information Administration databases supporting the following reports: Electric Power Monthly, DOE/EIA-0226; and Electric Power Annual, DOE/EIA-0348

(2) Wholesale electricity prices (except for PJM RTO price): S&P Global Market Intelligence, SNL Energy Data

(3) PJM ISO Western Hub wholesale electricity prices: PJM Data Miner website

Minor discrepancies with published historical data are due to independent rounding.

Projections: EIA Regional Short-Term Energy Model.

Table 7b. U.S. Regional Electricity Retail Sales (billion kilowatthours)
U.S. Energy Information Administration | Short-Term Energy Outlook - May 2020

	2019				2020				2021				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2019	2020	2021
Residential Sector															
New England	12.4	9.7	13.1	10.9	11.8	10.2	13.2	10.9	12.4	10.2	13.0	10.7	46.1	46.0	46.3
Middle Atlantic	35.3	27.7	40.3	29.8	32.7	29.1	39.7	29.2	34.1	28.9	39.1	29.0	133.1	130.7	131.2
E. N. Central	50.0	38.1	54.3	43.4	47.3	40.0	52.6	42.7	49.0	40.0	52.5	42.4	185.9	182.6	183.8
W. N. Central	29.9	21.6	29.0	24.9	28.0	22.0	28.9	24.1	28.1	22.4	29.2	24.0	105.4	102.9	103.7
S. Atlantic	88.3	84.5	111.4	84.4	83.9	85.7	109.4	80.9	89.6	85.1	110.5	80.8	368.5	359.9	366.0
E. S. Central	30.6	25.9	36.9	27.8	29.0	26.2	36.3	26.1	31.1	26.4	36.7	26.1	121.1	117.5	120.3
W. S. Central	51.7	49.0	75.8	50.6	49.9	53.0	75.3	48.2	50.7	52.2	75.7	48.5	227.1	226.4	227.1
Mountain	23.1	22.0	33.0	22.1	22.9	23.9	33.5	21.9	22.7	23.8	33.4	22.1	100.2	102.1	102.0
Pacific contiguous	39.0	29.6	38.7	35.8	37.3	30.8	39.5	35.7	37.0	30.9	39.4	35.7	143.1	143.3	142.9
AK and HI	1.2	1.1	1.2	1.3	1.2	1.1	1.2	1.3	1.2	1.1	1.2	1.2	4.7	4.8	4.8
Total	361.4	309.2	433.8	330.7	343.9	321.9	429.5	320.9	355.8	321.0	430.8	320.4	1,435.1	1,416.2	1,428.1
Commercial Sector															
New England	12.8	12.1	13.9	12.4	12.1	11.3	13.2	11.9	11.7	11.4	13.2	12.0	51.2	48.4	48.3
Middle Atlantic	38.6	36.3	41.9	35.9	36.0	31.7	35.9	32.2	33.5	34.5	39.0	33.8	152.6	135.8	140.8
E. N. Central	44.6	43.1	50.4	43.5	43.3	38.7	44.9	40.6	41.3	42.0	48.2	42.6	181.6	167.5	174.1
W. N. Central	25.6	24.2	27.9	24.8	25.1	22.4	26.4	24.1	24.5	24.0	27.5	24.8	102.5	97.9	100.8
S. Atlantic	72.1	79.4	90.1	75.5	71.1	69.3	81.3	70.0	67.5	75.1	86.8	73.5	317.0	291.7	302.9
E. S. Central	21.0	22.5	27.0	21.8	20.8	21.1	25.0	20.5	20.0	22.0	26.2	21.1	92.3	87.4	89.4
W. S. Central	43.2	47.6	58.0	46.9	43.7	46.3	54.8	44.7	42.3	48.2	57.5	46.4	195.7	189.6	194.4
Mountain	22.6	23.9	28.3	23.4	22.8	23.3	26.6	22.4	21.8	24.5	28.1	23.4	98.2	95.1	97.8
Pacific contiguous	38.0	37.9	42.9	39.0	36.5	34.5	39.8	37.0	34.9	36.9	41.1	37.1	157.9	147.7	149.9
AK and HI	1.4	1.4	1.5	1.4	1.4	1.3	1.3	1.5	1.5	1.4	1.5	1.5	5.7	5.5	5.9
Total	319.9	328.2	381.8	324.6	312.7	300.0	349.1	304.8	299.0	320.1	368.9	316.2	1,354.5	1,266.6	1,304.3
Industrial Sector															
New England	3.8	3.8	4.0	3.8	3.7	3.5	3.7	3.5	3.4	3.4	3.7	3.5	15.4	14.4	14.0
Middle Atlantic	17.7	17.5	19.8	18.2	17.9	16.7	18.6	17.0	16.6	16.7	18.9	17.5	73.2	70.1	69.6
E. N. Central	44.8	45.4	47.7	43.6	42.9	38.9	40.1	36.6	36.6	36.5	38.8	35.9	181.5	158.5	147.8
W. N. Central	21.1	22.0	23.4	21.8	21.3	20.1	21.2	19.6	19.3	20.3	22.1	20.7	88.3	82.1	82.4
S. Atlantic	33.0	34.8	36.2	33.4	32.7	32.1	33.2	30.6	30.2	32.0	33.8	31.4	137.5	128.6	127.5
E. S. Central	23.4	23.9	24.5	22.9	23.0	21.8	21.9	20.4	20.7	21.6	22.5	21.2	94.7	87.1	86.0
W. S. Central	44.8	47.7	50.2	46.6	45.3	45.3	47.0	43.5	42.3	45.8	48.8	45.6	189.5	181.1	182.6
Mountain	19.2	21.1	23.5	20.2	19.8	20.7	22.8	19.6	19.2	21.0	23.5	20.3	84.1	83.1	84.1
Pacific contiguous	19.1	20.4	23.4	20.2	18.9	19.9	22.5	19.3	17.9	19.6	22.3	19.2	83.1	80.7	79.0
AK and HI	1.1	1.2	1.3	1.3	1.1	1.2	1.3	1.2	1.1	1.2	1.3	1.2	4.9	4.8	4.8
Total	228.2	237.7	254.2	232.1	226.7	220.3	232.1	211.3	207.4	218.0	235.8	216.7	952.1	890.4	877.8
Total All Sectors (a)															
New England	29.1	25.6	31.3	27.2	27.7	25.1	30.2	26.4	27.7	25.2	29.9	26.3	113.3	109.3	109.2
Middle Atlantic	92.6	82.4	103.0	84.8	87.5	78.4	95.2	79.4	85.3	81.0	98.0	81.2	362.8	340.5	345.5
E. N. Central	139.6	126.7	152.6	130.7	133.8	117.8	137.7	120.0	127.1	118.6	139.7	121.0	549.6	509.2	506.3
W. N. Central	76.7	67.7	80.4	71.5	74.3	64.5	76.4	67.9	71.9	66.7	78.8	69.6	296.2	283.0	287.0
S. Atlantic	193.7	199.0	238.1	193.6	188.0	187.5	224.2	181.8	187.6	192.5	231.5	186.1	824.3	781.5	797.7
E. S. Central	75.0	72.3	88.3	72.4	72.8	69.1	83.1	67.0	71.8	70.0	85.4	68.4	308.1	292.0	295.7
W. S. Central	139.8	144.3	184.1	144.2	138.9	144.8	177.1	136.4	135.4	146.2	182.1	140.6	612.4	597.2	604.3
Mountain	65.0	67.1	84.8	65.7	65.6	67.9	82.9	64.0	63.7	69.3	85.0	65.9	282.7	280.4	284.0
Pacific contiguous	96.3	88.1	105.2	95.2	92.9	85.5	102.0	92.2	89.9	87.6	103.0	92.2	384.9	372.5	372.8
AK and HI	3.7	3.6	4.0	4.0	3.7	3.5	3.9	4.0	3.8	3.7	4.0	3.9	15.2	15.2	15.5
Total	911.5	876.9	1,071.8	889.3	885.2	844.0	1,012.8	839.0	864.3	860.9	1,037.5	855.3	3,749.5	3,581.0	3,617.9

- = no data available

(a) Total retail sales to all sectors includes residential, commercial, industrial, and transportation sector sales.

Notes: The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Retail Sales represents total retail electricity sales by electric utilities and power marketers.

Regions refer to U.S. Census divisions.

See "Census division" in EIA's Energy Glossary (http://www.eia.doe.gov/glossary/index.html) for a list of States in each region.

Historical data: Latest data available from U.S. Energy Information Administration databases supporting the following reports: *Electric Power Monthly* , DOE/EIA-0226; and *Electric Power Annual* , DOE/EIA-0348.

Minor discrepancies with published historical data are due to independent rounding.

Projections: EIA Regional Short-Term Energy Model.

Table 7c. U.S. Regional Retail Electricity Prices (Cents per Kilowatthour)
U.S. Energy Information Administration | Short-Term Energy Outlook - May 2020

	2019				2020				2021				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2019	2020	2021
Residential Sector															
New England	21.53	21.57	20.70	20.87	21.74	21.13	20.17	20.30	21.26	21.39	21.16	21.96	21.14	20.81	21.42
Middle Atlantic	15.19	16.06	16.15	15.78	15.31	15.68	15.85	15.76	15.58	16.36	16.69	16.40	15.79	15.66	16.27
E. N. Central	12.92	13.86	13.27	13.29	13.06	13.79	13.38	13.60	13.46	14.40	13.99	14.11	13.30	13.44	13.97
W. N. Central	10.71	12.78	12.93	11.24	10.94	12.96	13.27	11.70	11.39	13.50	13.80	12.10	11.87	12.20	12.69
S. Atlantic	11.70	12.17	12.11	11.87	11.78	11.98	11.91	11.70	11.52	12.10	12.15	12.05	11.97	11.85	11.96
E. S. Central	11.10	11.70	11.37	11.23	11.19	11.63	11.60	11.80	11.47	12.08	11.98	12.14	11.34	11.55	11.91
W. S. Central	10.88	11.50	11.36	11.24	10.94	11.17	11.13	11.17	10.95	11.49	11.57	11.63	11.25	11.10	11.42
Mountain	11.51	12.18	12.23	11.59	11.41	12.12	12.22	11.69	11.67	12.51	12.66	12.09	11.91	11.90	12.28
Pacific	14.86	15.88	17.31	14.64	15.67	16.59	17.61	14.62	15.76	17.18	18.08	14.99	15.68	16.14	16.51
U.S. Average	12.68	13.33	13.27	12.85	12.85	13.24	13.22	12.91	12.92	13.64	13.68	13.38	13.04	13.06	13.41
Commercial Sector															
New England	16.83	16.24	15.97	15.76	16.37	15.89	15.67	15.52	16.28	16.08	16.19	16.26	16.19	15.86	16.20
Middle Atlantic	11.57	12.18	13.03	11.97	11.48	11.55	12.30	11.56	11.43	12.02	12.93	11.97	12.21	11.73	12.12
E. N. Central	10.14	10.29	10.09	10.05	9.92	10.19	10.08	10.15	10.15	10.49	10.42	10.45	10.14	10.08	10.38
W. N. Central	8.98	10.04	10.41	9.11	9.07	10.27	10.74	9.51	9.55	10.70	11.21	9.82	9.65	9.90	10.34
S. Atlantic	9.44	9.37	9.35	9.35	9.24	9.23	9.18	9.20	9.19	9.26	9.35	9.46	9.37	9.21	9.32
E. S. Central	10.70	10.70	10.65	10.62	10.68	10.75	10.98	11.21	11.22	11.14	11.32	11.49	10.67	10.91	11.29
W. S. Central	8.12	8.00	8.30	8.06	7.90	7.80	8.16	8.03	7.97	7.90	8.31	8.12	8.13	7.98	8.09
Mountain	9.20	9.71	10.00	9.18	8.96	9.57	9.96	9.24	9.11	9.82	10.26	9.48	9.55	9.45	9.71
Pacific	12.98	14.15	16.35	14.44	13.32	14.10	16.14	14.29	13.34	14.56	16.96	15.20	14.54	14.51	15.09
U.S. Average	10.43	10.64	11.00	10.53	10.29	10.47	10.86	10.50	10.39	10.72	11.21	10.84	10.66	10.54	10.81
Industrial Sector															
New England	13.45	12.89	12.66	12.70	12.58	12.18	12.29	12.60	12.80	12.50	12.57	12.70	12.92	12.41	12.64
Middle Atlantic	6.73	6.52	6.54	6.40	6.33	6.21	6.34	6.41	6.61	6.47	6.55	6.41	6.55	6.32	6.51
E. N. Central	7.03	6.84	6.83	6.76	6.60	6.75	6.90	6.98	6.96	7.06	7.16	7.13	6.87	6.80	7.08
W. N. Central	7.13	7.33	8.09	6.87	7.00	7.57	8.46	7.23	7.39	7.86	8.72	7.41	7.37	7.57	7.87
S. Atlantic	6.22	6.28	6.72	6.18	6.02	6.09	6.58	6.17	6.15	6.26	6.74	6.21	6.36	6.22	6.35
E. S. Central	5.69	5.78	5.95	5.61	5.48	5.69	5.97	5.73	5.71	5.87	6.09	5.75	5.76	5.71	5.86
W. S. Central	5.25	5.28	6.05	5.29	5.12	5.24	6.05	5.47	5.50	5.54	6.35	5.56	5.48	5.48	5.75
Mountain	6.14	6.25	6.78	5.89	5.73	5.96	6.63	5.87	5.84	6.13	6.81	5.97	6.29	6.07	6.22
Pacific	8.65	9.45	11.26	10.16	8.81	9.56	11.47	10.48	9.20	9.97	11.96	10.85	9.95	10.14	10.57
U.S. Average	6.66	6.71	7.25	6.66	6.41	6.62	7.28	6.81	6.71	6.88	7.52	6.90	6.83	6.78	7.02
All Sectors (a)															
New England	18.35	17.72	17.50	17.34	18.11	17.47	17.19	17.07	18.05	17.72	17.86	18.06	17.73	17.46	17.92
Middle Atlantic	12.01	12.27	12.99	12.10	11.85	11.93	12.60	11.99	12.14	12.42	13.19	12.35	12.37	12.11	12.55
E. N. Central	10.13	10.12	10.20	10.03	9.96	10.28	10.41	10.41	10.50	10.75	10.86	10.74	10.12	10.26	10.71
W. N. Central	9.14	10.03	10.64	9.17	9.19	10.34	11.06	9.63	9.69	10.78	11.47	9.89	9.76	10.06	10.48
S. Atlantic	9.92	10.01	10.24	9.90	9.80	9.95	10.13	9.80	9.81	10.01	10.31	10.03	10.03	9.93	10.06
E. S. Central	9.30	9.43	9.65	9.27	9.24	9.49	9.93	9.77	9.74	9.87	10.23	9.96	9.42	9.62	9.96
W. S. Central	8.22	8.28	8.94	8.28	8.08	8.23	8.86	8.32	8.31	8.44	9.14	8.50	8.47	8.40	8.64
Mountain	9.12	9.43	9.98	8.98	8.84	9.36	9.95	9.05	9.04	9.63	10.25	9.27	9.42	9.34	9.60
Pacific	12.87	13.63	15.55	13.60	13.34	13.93	15.66	13.61	13.50	14.44	16.29	14.19	13.96	14.18	14.66
U.S. Average	10.37	10.52	11.03	10.38	10.29	10.52	11.04	10.49	10.54	10.83	11.40	10.79	10.60	10.60	10.92

- = no data available

Prices are not adjusted for inflation.

(a) Volume-weighted average of retail prices to residential, commercial, industrial, and transportation sectors.

Notes: The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Regions refer to U.S. Census divisions.

See "Census division" in EIA’s Energy Glossary (http://www.eia.doe.gov/glossary/index.html) for a list of States in each region.

Historical data: Latest data available from Energy Information Administration databases supporting the following reports: *Electric Power Monthly* , DOE/EIA-0226; and *Electric Power Annual* , DOE/EIA-0348.

Minor discrepancies with published historical data are due to independent rounding.

Projections: EIA Regional Short-Term Energy Model.

Table 7d part 1. U.S. Regional Electricity Generation, Electric Power Sector (billion kilowatthours), continues on Table 7d part 2

U.S. Energy Information Administration | Short-Term Energy Outlook - May 2020

	2019				2020				2021				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2019	2020	2021
United States															
Natural Gas	**317.1**	**330.9**	**473.7**	**353.0**	**349.3**	*337.1*	*460.2*	*320.1*	*285.9*	*319.3*	*430.6*	*316.3*	**1,474.7**	*1,466.7*	*1,352.2*
Coal	**257.9**	**208.9**	**279.4**	**213.3**	**177.1**	*157.5*	*214.2*	*175.4*	*199.3*	*174.4*	*246.9*	*189.6*	**959.5**	*724.2*	*810.3*
Nuclear	**203.5**	**196.5**	**210.2**	**199.2**	**204.2**	*189.1*	*208.2*	*198.3*	*198.4*	*189.6*	*204.3*	*190.1*	**809.4**	*799.8*	*782.4*
Renewable Energy Sources:	**169.9**	**192.9**	**161.3**	**163.9**	**187.8**	*208.2*	*179.4*	*185.6*	*209.1*	*228.2*	*196.3*	*200.2*	**688.0**	*761.0*	*833.8*
Conventional Hydropower	**71.2**	**81.7**	**60.8**	**58.7**	**74.6**	*83.8*	*68.0*	*62.9*	*72.5*	*81.5*	*64.2*	*62.0*	**272.4**	*289.2*	*280.1*
Wind	**74.2**	**78.6**	**66.2**	**80.8**	**85.7**	*87.8*	*72.0*	*94.2*	*103.3*	*101.6*	*83.7*	*104.2*	**299.8**	*339.7*	*392.9*
Solar (a)	**13.3**	**21.8**	**22.6**	**13.9**	**17.0**	*26.0*	*28.2*	*17.9*	*22.1*	*34.5*	*36.9*	*23.3*	**71.5**	*89.1*	*116.9*
Biomass	**7.2**	**7.0**	**7.6**	**6.9**	**6.7**	*6.8*	*7.0*	*7.0*	*7.6*	*6.8*	*7.3*	*7.1*	**28.8**	*27.5*	*28.8*
Geothermal	**4.0**	**3.9**	**4.1**	**3.6**	**3.8**	*3.8*	*4.3*	*3.6*	*3.5*	*3.8*	*4.2*	*3.6*	**15.6**	*15.5*	*15.1*
Pumped Storage Hydropower	**-1.1**	**-0.9**	**-1.9**	**-1.4**	**-1.0**	*-0.6*	*-1.8*	*-1.4*	*-1.1*	*-0.7*	*-1.8*	*-1.3*	**-5.3**	*-4.8*	*-5.0*
Petroleum (b)	**4.9**	**4.2**	**4.8**	**3.5**	**4.2**	*4.3*	*4.3*	*3.4*	*4.9*	*4.2*	*4.4*	*3.1*	**17.3**	*16.2*	*16.6*
Other Gases	**1.1**	**1.0**	**1.2**	**1.0**	**1.2**	*1.2*	*1.1*	*0.8*	*1.0*	*1.0*	*1.1*	*0.9*	**4.3**	*4.2*	*4.0*
Other Nonrenewable Fuels (c)	**1.9**	**1.9**	**2.0**	**1.9**	**1.9**	*1.9*	*1.9*	*1.7*	*1.7*	*1.9*	*1.8*	*1.7*	**7.7**	*7.4*	*7.0*
Total Generation	**955.2**	**935.5**	**1,130.7**	**934.4**	**924.6**	*898.7*	*1,067.6*	*883.8*	*899.2*	*917.8*	*1,083.6*	*900.6*	**3,955.8**	*3,774.7*	*3,801.3*
New England (ISO-NE)															
Natural Gas	**10.6**	**10.0**	**14.8**	**11.5**	**12.0**	*10.8*	*13.8*	*9.5*	*8.4*	*8.2*	*13.2*	*10.2*	**46.9**	*46.1*	*40.0*
Coal	**0.3**	**0.0**	**0.1**	**0.1**	**0.1**	*0.0*	*0.1*	*0.1*	*0.4*	*0.0*	*0.1*	*0.3*	**0.5**	*0.3*	*0.9*
Nuclear	**8.6**	**6.8**	**7.3**	**7.1**	**7.4**	*5.3*	*7.2*	*6.2*	*7.1*	*7.1*	*7.2*	*5.6*	**29.8**	*26.1*	*27.0*
Conventional hydropower	**2.1**	**1.9**	**1.5**	**1.6**	**2.1**	*1.9*	*1.5*	*1.6*	*2.0*	*1.8*	*1.4*	*1.5*	**7.0**	*7.1*	*6.7*
Nonhydro renewables (d)	**2.6**	**2.7**	**2.6**	**2.5**	**2.6**	*2.8*	*2.6*	*2.7*	*3.4*	*2.8*	*2.7*	*2.8*	**10.3**	*10.7*	*11.7*
Other energy sources (e)	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	*0.3*	*0.4*	*0.5*	*1.3*	*0.3*	*0.4*	*0.4*	**1.5**	*1.5*	*2.3*
Total generation	**24.5**	**21.7**	**26.5**	**23.3**	**24.5**	*21.1*	*25.6*	*20.6*	*22.6*	*20.3*	*25.0*	*20.8*	**96.1**	*91.8*	*88.6*
Net energy for load (f)	**29.5**	**25.8**	**31.9**	**28.0**	**27.6**	*25.4*	*31.1*	*27.1*	*28.4*	*26.4*	*31.3*	*27.6*	**115.2**	*111.2*	*113.7*
New York (NYISO)															
Natural Gas	**11.9**	**11.1**	**18.4**	**12.6**	**12.8**	*14.2*	*21.6*	*15.1*	*12.1*	*18.1*	*22.3*	*16.3*	**54.0**	*63.7*	*68.8*
Coal	**0.3**	**0.0**	**0.1**	**0.0**	**0.0**	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	**0.4**	*0.0*	*0.0*
Nuclear	**10.4**	**10.8**	**11.8**	**11.8**	**10.8**	*9.4*	*8.8*	*9.1*	*8.8*	*7.5*	*7.1*	*6.8*	**44.9**	*38.1*	*30.3*
Conventional hydropower	**7.4**	**7.3**	**7.4**	**7.4**	**7.8**	*7.0*	*8.0*	*7.3*	*7.5*	*6.6*	*7.4*	*7.0*	**29.5**	*30.1*	*28.5*
Nonhydro renewables (d)	**1.6**	**1.8**	**1.5**	**1.6**	**1.8**	*1.9*	*1.6*	*1.9*	*2.3*	*2.3*	*2.1*	*2.8*	**6.5**	*7.2*	*9.6*
Other energy sources (e)	**0.4**	**0.1**	**0.2**	**0.2**	**0.1**	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*	*0.2*	*0.2*	**0.9**	*0.6*	*0.6*
Total generation	**32.1**	**31.1**	**39.3**	**33.6**	**33.3**	*32.7*	*40.2*	*33.6*	*30.9*	*34.6*	*39.2*	*33.1*	**136.2**	*139.9*	*137.8*
Net energy for load (f)	**37.4**	**34.3**	**43.3**	**35.7**	**35.0**	*33.9*	*41.9*	*34.7*	*35.8*	*35.4*	*42.6*	*35.7*	**150.6**	*145.5*	*149.5*
Mid-Atlantic (PJM)															
Natural Gas	**69.3**	**64.2**	**90.9**	**70.7**	**75.7**	*69.5*	*98.7*	*66.9*	*66.8*	*72.9*	*92.2*	*65.2*	**295.1**	*310.8*	*297.1*
Coal	**53.5**	**39.9**	**52.0**	**38.9**	**35.8**	*24.8*	*29.4*	*30.5*	*47.3*	*28.7*	*41.5*	*37.7*	**184.3**	*120.4*	*155.1*
Nuclear	**69.6**	**68.5**	**71.7**	**68.1**	**68.6**	*66.9*	*71.0*	*69.4*	*67.6*	*65.7*	*71.8*	*68.2*	**277.9**	*275.9*	*273.2*
Conventional hydropower	**3.4**	**3.0**	**1.9**	**2.2**	**3.1**	*2.5*	*1.8*	*2.2*	*3.0*	*2.4*	*1.7*	*2.1*	**10.6**	*9.7*	*9.2*
Nonhydro renewables (d)	**8.8**	**9.3**	**7.1**	**8.9**	**9.8**	*10.3*	*8.0*	*10.2*	*11.1*	*11.8*	*9.1*	*10.9*	**34.1**	*38.2*	*42.9*
Other energy sources (e)	**0.9**	**0.7**	**0.5**	**0.4**	**0.7**	*0.9*	*0.4*	*0.3*	*0.7*	*0.8*	*0.4*	*0.3*	**2.5**	*2.3*	*2.2*
Total generation	**205.4**	**185.6**	**224.1**	**189.2**	**193.7**	*174.9*	*209.3*	*179.5*	*196.5*	*182.2*	*216.6*	*184.4*	**804.4**	*757.4*	*779.7*
Net energy for load (f)	**195.1**	**173.0**	**212.3**	**180.4**	**181.0**	*162.4*	*196.8*	*169.8*	*183.9*	*170.0*	*201.6*	*174.6*	**760.9**	*710.1*	*730.1*
Southeast (SERC)															
Natural Gas	**56.3**	**59.2**	**77.8**	**59.6**	**63.4**	*64.2*	*80.7*	*62.0*	*58.0*	*61.2*	*72.9*	*60.5*	**252.9**	*270.3*	*252.6*
Coal	**35.1**	**38.0**	**53.3**	**33.5**	**24.4**	*36.6*	*39.9*	*28.0*	*29.6*	*34.1*	*44.3*	*29.7*	**159.8**	*128.9*	*137.7*
Nuclear	**52.3**	**52.8**	**53.7**	**52.2**	**53.1**	*49.4*	*55.5*	*52.7*	*52.3*	*52.3*	*55.4*	*51.4*	**211.0**	*210.6*	*211.5*
Conventional hydropower	**10.9**	**9.3**	**7.1**	**8.2**	**10.5**	*8.0*	*6.8*	*8.0*	*10.0*	*7.4*	*6.4*	*7.6*	**35.5**	*33.2*	*31.4*
Nonhydro renewables (d)	**2.6**	**3.8**	**3.9**	**2.8**	**3.2**	*4.7*	*4.6*	*3.3*	*4.1*	*6.0*	*5.9*	*4.0*	**13.2**	*15.8*	*20.0*
Other energy sources (e)	**0.0**	**-0.2**	**-0.6**	**-0.4**	**0.0**	*0.1*	*-0.6*	*-0.4*	*-0.1*	*-0.1*	*-0.6*	*-0.4*	**-1.2**	*-0.9*	*-1.2*
Total generation	**157.2**	**162.9**	**195.2**	**155.8**	**154.5**	*163.0*	*186.8*	*153.6*	*154.0*	*160.9*	*184.2*	*152.9*	**671.1**	*657.9*	*651.9*
Net energy for load (f)	**163.9**	**158.5**	**197.9**	**157.3**	**159.5**	*163.9*	*190.0*	*154.1*	*158.8*	*158.8*	*187.0*	*153.4*	**677.6**	*667.5*	*658.1*
Florida (FRCC)															
Natural Gas	**35.5**	**46.4**	**52.6**	**39.9**	**37.3**	*44.5*	*51.5*	*37.1*	*31.7*	*44.1*	*47.7*	*36.7*	**174.4**	*170.4*	*160.3*
Coal	**3.7**	**4.8**	**5.3**	**4.8**	**2.5**	*3.6*	*2.1*	*3.4*	*4.7*	*4.1*	*6.0*	*4.4*	**18.6**	*11.7*	*19.2*
Nuclear	**7.6**	**6.4**	**7.7**	**7.3**	**7.3**	*7.4*	*7.5*	*7.7*	*7.8*	*7.0*	*7.2*	*7.4*	**29.1**	*29.9*	*29.4*
Conventional hydropower	**0.1**	**0.1**	**0.0**	**0.1**	**0.1**	*0.1*	*0.0*	*0.1*	*0.1*	*0.1*	*0.0*	*0.0*	**0.2**	*0.2*	*0.2*
Nonhydro renewables (d)	**1.5**	**1.7**	**1.6**	**1.4**	**1.7**	*2.3*	*2.1*	*1.9*	*2.2*	*3.0*	*2.8*	*2.3*	**6.2**	*8.0*	*10.3*
Other energy sources (e)	**0.8**	**0.9**	**0.8**	**0.7**	**0.9**	*0.9*	*0.7*	*0.7*	*0.8*	*0.8*	*0.7*	*0.7*	**3.1**	*3.2*	*3.1*
Total generation	**49.3**	**60.2**	**68.1**	**54.1**	**49.7**	*58.8*	*64.1*	*50.8*	*47.3*	*59.1*	*64.4*	*51.6*	**231.7**	*223.4*	*222.4*
Net energy for load (f)	**48.0**	**58.4**	**69.4**	**53.1**	**48.3**	*57.1*	*65.2*	*49.7*	*46.1*	*57.5*	*66.5*	*51.0*	**229.0**	*220.3*	*221.1*

Notes: The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Data reflect generation supplied by power plants with a combined capacity of at least 1 megawatt operated by electric utilities and independent power producers.

(a) Solar generation from large-scale power plants with more than 1 megawatt of capacity. Excludes generation from small-scale solar photovoltaic systems.

(b) Residual fuel oil, distillate fuel oil, petroleum coke, and other petroleum liquids.

(c) Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, nonrenewable waste, and miscellaneous technologies.

(d) Wind, large-scale solar, biomass, and geothermal

(e) Pumped storage hydroelectric, petroleum, other gases, batteries, and other nonrenewable fuels. See notes (b) and (c).

(f) Regional generation from generating units operated by electric power sector, plus energy receipts from minus energy deliveries to U.S. balancing authorities outside region.

Historical data: Latest data available from U.S. Energy Information Administration databases supporting the following reports: *Electric Power Monthly* , DOE/EIA-0226;

Projections: EIA Regional Short-Term Energy Model.

Table 7d part 2. U.S. Regional Electricity Generation, Electric Power Sector (billion kilowatthours), *continued from Table 7d part 1*

U.S. Energy Information Administration | Short-Term Energy Outlook - May 2020

	2019				2020				2021				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2019	2020	2021
Midwest (MISO)															
Natural Gas	**35.9**	**40.9**	**58.1**	**42.3**	**44.2**	*43.6*	*56.0*	*39.8*	*34.7*	*39.2*	*53.2*	*38.7*	**177.2**	*183.5*	*165.8*
Coal	**77.5**	**61.2**	**76.2**	**61.3**	**52.9**	*48.2*	*63.8*	*51.9*	*59.4*	*53.9*	*71.1*	*58.2*	**276.2**	*216.8*	*242.6*
Nuclear	**25.3**	**23.2**	**27.1**	**26.7**	**26.6**	*22.9*	*26.9*	*24.8*	*24.9*	*23.9*	*25.0*	*22.9*	**102.3**	*101.1*	*96.7*
Conventional hydropower	**2.2**	**2.3**	**1.7**	**1.8**	**2.3**	*2.3*	*1.7*	*1.8*	*2.3*	*2.2*	*1.6*	*1.8*	**8.0**	*8.2*	*7.9*
Nonhydro renewables (d)	**16.7**	**17.3**	**13.5**	**18.6**	**19.6**	*19.3*	*16.0*	*22.7*	*23.6*	*23.2*	*18.6*	*24.7*	**66.1**	*77.6*	*90.1*
Other energy sources (e)	**2.0**	**1.4**	**1.7**	**0.9**	**1.6**	*1.8*	*1.7*	*0.8*	*1.3*	*1.6*	*1.6*	*0.9*	**6.0**	*5.9*	*5.4*
Total generation	**159.5**	**146.3**	**178.2**	**151.7**	**147.2**	*138.1*	*166.1*	*141.8*	*146.2*	*144.0*	*171.1*	*147.2*	**635.7**	*593.2*	*608.5*
Net energy for load (f)	**159.6**	**151.5**	**180.6**	**153.8**	**151.7**	*142.0*	*168.3*	*144.6*	*147.6*	*148.1*	*172.1*	*148.4*	**645.6**	*606.6*	*616.2*
Central (Southwest Power Pool)															
Natural Gas	**14.0**	**15.8**	**26.1**	**15.3**	**16.8**	*13.6*	*22.1*	*12.2*	*9.6*	*10.8*	*20.7*	*11.0*	**71.1**	*64.7*	*52.1*
Coal	**27.3**	**19.1**	**27.3**	**19.5**	**19.5**	*8.0*	*23.0*	*12.3*	*15.6*	*10.5*	*22.4*	*12.3*	**93.3**	*62.7*	*60.8*
Nuclear	**4.4**	**4.4**	**4.1**	**3.4**	**4.4**	*4.4*	*4.4*	*3.5*	*3.9*	*3.3*	*4.4*	*4.4*	**16.2**	*16.7*	*16.0*
Conventional hydropower	**3.9**	**4.1**	**2.7**	**3.0**	**4.0**	*3.7*	*2.6*	*2.9*	*3.8*	*3.5*	*2.4*	*2.8*	**13.7**	*13.2*	*12.5*
Nonhydro renewables (d)	**18.1**	**18.5**	**17.5**	**20.9**	**20.2**	*19.7*	*17.2*	*23.4*	*25.8*	*24.4*	*21.7*	*26.9*	**75.0**	*80.5*	*98.8*
Other energy sources (e)	**0.2**	**0.3**	**0.1**	**0.1**	**0.2**	*0.3*	*0.1*	*0.1*	*0.1*	*0.3*	*0.0*	*0.1*	**0.8**	*0.6*	*0.5*
Total generation	**68.0**	**62.1**	**77.7**	**62.3**	**65.1**	*49.6*	*69.3*	*54.4*	*58.9*	*52.7*	*71.7*	*57.4*	**270.1**	*238.5*	*240.8*
Net energy for load (f)	**62.5**	**68.4**	**73.6**	**61.8**	**62.7**	*53.5*	*68.0*	*54.3*	*55.8*	*57.6*	*70.9*	*56.7*	**266.2**	*238.6*	*241.0*
Texas (ERCOT)															
Natural Gas	**34.7**	**43.1**	**62.3**	**40.1**	**36.7**	*40.1*	*50.1*	*28.8*	*22.8*	*30.5*	*47.0*	*26.1*	**180.1**	*155.7*	*126.4*
Coal	**18.1**	**18.3**	**21.6**	**17.2**	**13.5**	*12.5*	*19.3*	*14.5*	*14.6*	*17.3*	*20.0*	*16.5*	**75.2**	*59.9*	*68.4*
Nuclear	**10.4**	**9.8**	**11.0**	**10.2**	**10.5**	*9.4*	*11.0*	*10.0*	*10.7*	*9.8*	*10.3*	*9.4*	**41.3**	*40.8*	*40.2*
Conventional hydropower	**0.3**	**0.2**	**0.1**	**0.1**	**0.3**	*0.2*	*0.1*	*0.1*	*0.3*	*0.2*	*0.1*	*0.1*	**0.7**	*0.7*	*0.7*
Nonhydro renewables (d)	**19.3**	**21.4**	**19.5**	**20.9**	**22.9**	*26.8*	*23.4*	*24.8*	*26.8*	*31.7*	*29.3*	*28.5*	**81.1**	*97.9*	*116.3*
Other energy sources (e)	**0.4**	**0.4**	**0.4**	**0.4**	**0.4**	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	*0.4*	**1.6**	*1.5*	*1.5*
Total generation	**83.2**	**93.2**	**114.9**	**88.9**	**84.3**	*89.4*	*104.2*	*78.6*	*75.6*	*89.9*	*107.1*	*80.9*	**380.2**	*356.5*	*353.5*
Net energy for load (f)	**83.2**	**93.2**	**114.9**	**88.9**	**84.3**	*89.4*	*104.2*	*78.6*	*75.6*	*89.9*	*107.1*	*80.9*	**380.2**	*356.5*	*353.5*
Northwest															
Natural Gas	**20.1**	**16.7**	**29.4**	**23.1**	**21.7**	*10.7*	*22.8*	*14.2*	*16.3*	*9.4*	*20.2*	*15.2*	**89.2**	*69.5*	*61.1*
Coal	**29.7**	**18.0**	**29.4**	**27.9**	**20.6**	*16.2*	*26.2*	*25.9*	*20.9*	*18.3*	*31.1*	*23.7*	**105.1**	*89.0*	*93.9*
Nuclear	**2.5**	**1.3**	**2.5**	**2.6**	**2.5**	*2.5*	*2.4*	*2.4*	*2.4*	*1.2*	*2.4*	*2.4*	**8.9**	*9.8*	*8.4*
Conventional hydropower	**30.5**	**36.5**	**24.6**	**26.4**	**35.2**	*41.8*	*30.7*	*30.6*	*34.7*	*42.5*	*29.5*	*31.0*	**118.0**	*138.4*	*137.7*
Nonhydro renewables (d)	**11.2**	**13.4**	**12.0**	**11.8**	**13.7**	*14.4*	*13.2*	*14.3*	*17.8*	*17.4*	*15.7*	*16.7*	**48.4**	*55.6*	*67.6*
Other energy sources (e)	**0.2**	**0.2**	**0.3**	**0.2**	**0.2**	*0.2*	*0.2*	*0.1*	*0.2*	*0.2*	*0.2*	*0.1*	**0.9**	*0.8*	*0.8*
Total generation	**94.3**	**86.2**	**98.1**	**92.0**	**93.9**	*85.9*	*95.5*	*87.7*	*92.2*	*88.9*	*99.2*	*89.2*	**370.5**	*363.1*	*369.5*
Net energy for load (f)	**94.5**	**83.1**	**92.2**	**87.7**	**88.4**	*80.0*	*89.6*	*84.2*	*85.1*	*81.4*	*90.3*	*84.7*	**357.4**	*342.2*	*341.4*
Southwest															
Natural Gas	**10.4**	**12.7**	**19.1**	**14.3**	**12.0**	*14.5*	*16.5*	*10.7*	*10.7*	*15.7*	*17.8*	*12.7*	**56.5**	*53.7*	*56.8*
Coal	**9.7**	**7.9**	**11.8**	**7.4**	**5.8**	*6.0*	*8.5*	*6.0*	*4.7*	*5.2*	*8.1*	*4.1*	**36.7**	*26.4*	*22.1*
Nuclear	**8.6**	**7.6**	**8.6**	**7.2**	**8.3**	*7.6*	*8.6*	*7.6*	*8.4*	*7.6*	*8.6*	*7.6*	**31.9**	*32.1*	*32.2*
Conventional hydropower	**3.0**	**4.3**	**4.0**	**2.6**	**3.0**	*4.0*	*4.2*	*2.6*	*2.9*	*3.5*	*3.9*	*2.5*	**13.9**	*13.8*	*12.7*
Nonhydro renewables (d)	**2.1**	**2.8**	**2.7**	**2.4**	**2.5**	*3.0*	*2.7*	*2.7*	*4.0*	*4.3*	*3.7*	*3.6*	**9.9**	*11.0*	*15.5*
Other energy sources (e)	**0.0**	**0.0**	**0.1**	**0.0**	**0.0**	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.1*	*0.0*	**0.0**	*0.0*	*0.1*
Total generation	**33.8**	**35.3**	**46.1**	**33.7**	**31.6**	*35.1*	*40.6*	*29.7*	*30.6*	*36.2*	*42.2*	*30.4*	**148.9**	*137.1*	*139.4*
Net energy for load (f)	**18.2**	**23.1**	**34.0**	**22.3**	**22.0**	*26.4*	*33.9*	*22.8*	*21.9*	*27.0*	*34.5*	*23.2*	**97.7**	*105.1*	*106.6*
California															
Natural Gas	**17.7**	**10.2**	**23.4**	**22.9**	**15.9**	*10.7*	*25.6*	*22.9*	*14.0*	*8.6*	*22.6*	*22.8*	**74.2**	*75.2*	*68.1*
Coal	**2.2**	**1.2**	**1.9**	**2.2**	**1.4**	*1.1*	*1.5*	*2.3*	*1.6*	*2.0*	*1.9*	*2.3*	**7.5**	*6.3*	*7.8*
Nuclear	**3.8**	**4.9**	**4.7**	**2.8**	**4.9**	*3.9*	*4.9*	*4.9*	*4.5*	*4.1*	*4.9*	*3.9*	**16.2**	*18.6*	*17.4*
Conventional hydropower	**7.1**	**12.4**	**9.6**	**4.9**	**5.9**	*11.8*	*10.1*	*5.2*	*5.6*	*11.1*	*9.5*	*5.0*	**34.0**	*33.1*	*31.2*
Nonhydro renewables (d)	**13.8**	**18.3**	**18.5**	**13.1**	**14.9**	*18.8*	*19.6*	*14.2*	*15.0*	*19.4*	*20.0*	*14.6*	**63.7**	*67.5*	*69.0*
Other energy sources (e)	**-0.2**	**0.2**	**0.2**	**0.0**	**0.0**	*0.2*	*0.2*	*0.0*	*0.0*	*0.2*	*0.2*	*0.0*	**0.2**	*0.4*	*0.4*
Total generation	**44.4**	**47.2**	**58.3**	**45.9**	**42.9**	*46.6*	*62.0*	*49.5*	*40.6*	*45.4*	*59.1*	*48.8*	**195.8**	*201.1*	*193.9*
Net energy for load (f)	**59.8**	**62.5**	**76.3**	**61.6**	**58.1**	*61.2*	*74.7*	*60.0*	*56.5*	*62.1*	*75.7*	*60.5*	**260.2**	*253.9*	*254.9*

Notes: The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Data reflect generation supplied by power plants with a combined capacity of at least 1 megawatt operated by electric utilities and independent power producers.

(a) Large-scale solar generation from power plants with more than 1 megawatt of capacity. Excludes generation from small-scale solar photovoltaic systems.

(b) Residual fuel oil, distillate fuel oil, petroleum coke, and other petroleum liquids.

(c) Batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, nonrenewable waste, and miscellaneous technologies.

(d) Wind, large-scale solar, biomass, and geothermal

(e) Pumped storage hydroelectric, petroleum, other gases, batteries, and other nonrenewable fuels. See notes (b) and (c).

(f) Regional generation from generating units operated by electric power sector, plus energy receipts from minus energy deliveries to U.S. balancing authorities outside region.

Historical data: Latest data available from U.S. Energy Information Administration databases supporting the following reports: *Electric Power Monthly* , DOE/EIA-0226;

Projections: EIA Regional Short-Term Energy Model.

Table 8a. U.S. Renewable Energy Consumption (Quadrillion Btu)

U.S. Energy Information Administration | Short-Term Energy Outlook - May 2020

	2019				2020				2021				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2019	2020	2021
Electric Power Sector															
Geothermal	0.037	0.035	0.037	0.033	0.035	0.035	0.039	0.033	0.032	0.034	0.038	0.033	0.142	0.142	0.138
Hydroelectric Power (a)	0.649	0.743	0.553	0.534	0.679	0.767	0.611	0.570	0.666	0.746	0.583	0.562	2.480	2.627	2.557
Solar (b)	0.122	0.201	0.208	0.128	0.157	0.240	0.259	0.165	0.204	0.318	0.340	0.215	0.659	0.821	1.077
Waste Biomass (c)	0.059	0.058	0.059	0.060	0.058	0.056	0.058	0.058	0.059	0.057	0.060	0.059	0.236	0.230	0.235
Wood Biomass	0.053	0.052	0.058	0.048	0.047	0.050	0.051	0.051	0.060	0.049	0.055	0.052	0.211	0.199	0.215
Wind	0.683	0.724	0.610	0.745	0.790	0.809	0.664	0.868	0.952	0.936	0.771	0.960	2.762	3.130	3.620
Subtotal	1.603	1.813	1.526	1.547	1.765	1.956	1.682	1.744	1.973	2.141	1.847	1.880	6.490	7.148	7.841
Industrial Sector															
Biofuel Losses and Co-products (d)	0.194	0.203	0.199	0.203	0.196	0.133	0.166	0.182	0.180	0.189	0.191	0.195	0.799	0.677	0.754
Geothermal	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.004	0.004	0.004
Hydroelectric Power (a)	0.003	0.003	0.002	0.003	0.003	0.003	0.002	0.003	0.003	0.003	0.002	0.003	0.010	0.010	0.010
Solar (b)	0.006	0.008	0.009	0.006	0.007	0.010	0.010	0.007	0.007	0.011	0.011	0.008	0.029	0.033	0.037
Waste Biomass (c)	0.042	0.038	0.037	0.043	0.042	0.040	0.039	0.042	0.041	0.040	0.040	0.042	0.160	0.163	0.163
Wood Biomass	0.373	0.363	0.369	0.368	0.344	0.338	0.342	0.340	0.328	0.327	0.340	0.344	1.473	1.364	1.339
Subtotal	0.617	0.613	0.614	0.622	0.590	0.518	0.555	0.571	0.557	0.564	0.579	0.588	2.466	2.235	2.288
Commercial Sector															
Geothermal	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.006	0.024	0.023	0.023
Solar (b)	0.022	0.032	0.032	0.022	0.026	0.036	0.036	0.025	0.028	0.041	0.041	0.029	0.108	0.123	0.139
Waste Biomass (c)	0.010	0.008	0.009	0.009	0.009	0.008	0.009	0.009	0.009	0.009	0.009	0.009	0.036	0.036	0.036
Wood Biomass	0.021	0.021	0.021	0.021	0.021	0.020	0.022	0.021	0.021	0.020	0.022	0.021	0.084	0.084	0.084
Subtotal	0.065	0.074	0.075	0.065	0.068	0.076	0.079	0.067	0.070	0.082	0.085	0.071	0.280	0.290	0.309
Residential Sector															
Geothermal	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.010	0.040	0.040	0.040
Solar (e)	0.050	0.076	0.078	0.052	0.060	0.089	0.089	0.061	0.066	0.100	0.102	0.070	0.257	0.299	0.337
Wood Biomass	0.130	0.132	0.133	0.133	0.128	0.132	0.133	0.133	0.128	0.132	0.133	0.133	0.529	0.526	0.526
Subtotal	0.190	0.218	0.221	0.195	0.197	0.231	0.232	0.204	0.203	0.242	0.245	0.214	0.825	0.865	0.903
Transportation Sector															
Biomass-based Diesel (f)	0.058	0.071	0.070	0.066	0.067	0.066	0.063	0.069	0.084	0.089	0.079	0.085	0.265	0.264	0.337
Ethanol (f)	0.274	0.293	0.291	0.296	0.256	0.210	0.260	0.269	0.254	0.276	0.280	0.277	1.154	0.995	1.087
Subtotal	0.333	0.365	0.361	0.361	0.322	0.276	0.323	0.338	0.338	0.365	0.358	0.362	1.419	1.259	1.424
All Sectors Total															
Biomass-based Diesel (f)	0.058	0.071	0.070	0.066	0.067	0.066	0.063	0.069	0.084	0.089	0.079	0.085	0.265	0.264	0.337
Biofuel Losses and Co-products (d)	0.194	0.203	0.199	0.203	0.196	0.133	0.166	0.182	0.180	0.189	0.191	0.195	0.799	0.677	0.754
Ethanol (f)	0.285	0.305	0.302	0.307	0.266	0.219	0.270	0.279	0.264	0.287	0.291	0.288	1.199	1.033	1.129
Geothermal	0.054	0.052	0.054	0.050	0.051	0.052	0.056	0.050	0.049	0.051	0.055	0.050	0.209	0.208	0.205
Hydroelectric Power (a)	0.652	0.747	0.556	0.537	0.682	0.770	0.614	0.573	0.669	0.749	0.586	0.565	2.492	2.639	2.569
Solar (b)(e)	0.198	0.315	0.324	0.206	0.248	0.375	0.394	0.257	0.305	0.469	0.494	0.322	1.043	1.275	1.590
Waste Biomass (c)	0.111	0.105	0.105	0.112	0.110	0.104	0.106	0.109	0.109	0.106	0.108	0.110	0.433	0.429	0.433
Wood Biomass	0.578	0.568	0.582	0.570	0.540	0.540	0.548	0.545	0.537	0.528	0.550	0.550	2.297	2.173	2.164
Wind	0.683	0.724	0.610	0.745	0.790	0.809	0.664	0.868	0.952	0.936	0.771	0.960	2.762	3.130	3.620
Total Consumption	2.809	3.084	2.798	2.791	2.943	3.058	2.871	2.924	3.142	3.393	3.113	3.116	11.481	11.797	12.764

\- = no data available

(a) Conventional hydroelectric power only. Hydroelectricity generated by pumped storage is not included in renewable energy.

(b) Solar consumption in the electric power, commercial, and industrial sectors includes energy produced from large scale (>1 MW) solar thermal and photovoltaic generators and small-scale (<1 MW) distributed solar photovoltaic systems.

(c) Municipal solid waste from biogenic sources, landfill gas, sludge waste, agricultural byproducts, and other biomass.

(d) Losses and co-products from the production of fuel ethanol and biomass-based diesel

(e) Solar consumption in the residential sector includes energy from small-scale (<1 MW) solar photovoltaic systems. Also includes solar heating consumption in all sectors.

(f) Fuel ethanol and biomass-based diesel consumption in the transportation sector includes production, stock change, and imports less exports. Some biomass-based diesel may be consumed in the residential sector in heating oil.

Notes: The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Historical data: Latest data available from EIA databases supporting the following reports: *Electric Power Monthly,* DOE/EIA-0226 and *Renewable Energy Annual,* DOE/EIA-0603; *Petroleum Supply Monthly,* DOE/EIA-0109.

Minor discrepancies with published historical data are due to independent rounding.

Projections: EIA Regional Short-Term Energy Model.

Table 8b. U.S. Renewable Electricity Generation and Capacity

U.S. Energy Information Administration | Short-Term Energy Outlook - May 2020

	2019				2020				2021				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2019	2020	2021
Renewable Energy Electric Generating Capacity (megawatts, end of period)															
Electric Power Sector (a)															
Biomass	6,915	6,868	6,769	6,776	6,777	6,699	6,735	6,739	6,742	6,761	6,681	6,769	6,776	6,739	6,769
Waste	4,112	4,080	4,070	4,049	4,050	3,972	4,009	4,012	4,015	4,034	3,954	4,042	4,049	4,012	4,042
Wood	2,803	2,788	2,699	2,727	2,727	2,727	2,727	2,727	2,727	2,727	2,727	2,727	2,727	2,727	2,727
Conventional Hydroelectric	79,574	79,553	79,377	79,433	79,443	79,489	79,617	79,632	79,726	79,684	79,761	79,781	79,433	79,632	79,781
Geothermal	2,488	2,488	2,488	2,508	2,508	2,508	2,508	2,508	2,508	2,508	2,508	2,550	2,508	2,508	2,550
Large-Scale Solar (b)	32,664	33,129	33,789	36,870	38,692	40,722	41,969	49,573	50,244	54,329	55,782	60,633	36,870	49,573	60,633
Wind	96,610	98,085	99,661	103,451	105,620	106,839	109,819	123,845	123,857	125,144	125,670	129,095	103,451	123,845	129,095
Other Sectors (c)															
Biomass	6,569	6,518	6,518	6,452	6,460	6,456	6,456	6,456	6,462	6,409	6,409	6,409	6,452	6,456	6,409
Waste	782	784	784	784	784	800	800	800	800	799	799	799	784	800	799
Wood	5,787	5,734	5,734	5,668	5,676	5,656	5,656	5,656	5,662	5,610	5,610	5,610	5,668	5,656	5,610
Conventional Hydroelectric	289	289	289	289	289	289	289	289	289	291	289	289	289	289	289
Large-Scale Solar (b)	408	414	425	430	430	435	437	437	437	437	438	438	430	437	438
Small-Scale Solar (d)	20,284	21,137	22,103	23,211	24,216	24,543	25,195	26,211	27,229	28,400	29,738	31,151	23,211	26,211	31,151
Residential Sector	12,271	12,840	13,526	14,229	14,943	15,136	15,574	16,251	16,903	17,694	18,639	19,644	14,229	16,251	19,644
Commercial Sector	6,402	6,609	6,841	7,186	7,408	7,500	7,665	7,947	8,252	8,572	8,903	9,248	7,186	7,947	9,248
Industrial Sector	1,611	1,688	1,736	1,796	1,865	1,907	1,956	2,013	2,073	2,134	2,196	2,259	1,796	2,013	2,259
Wind	118	118	118	118	123	292	292	292	292	292	292	292	118	292	292
Renewable Electricity Generation (billion kilowatthours)															
Electric Power Sector (a)															
Biomass	7.2	7.0	7.6	6.9	6.7	6.8	7.0	7.0	7.6	6.8	7.3	7.1	28.8	27.5	28.8
Waste	3.9	3.9	4.0	3.9	3.8	3.7	3.9	3.8	3.9	3.8	3.9	3.9	15.7	15.2	15.5
Wood	3.3	3.1	3.6	3.0	2.9	3.1	3.1	3.1	3.7	3.0	3.4	3.2	13.0	12.3	13.3
Conventional Hydroelectric	71.2	81.7	60.8	58.7	74.6	83.8	68.0	62.9	72.5	81.5	64.2	62.0	272.4	289.2	280.1
Geothermal	4.0	3.9	4.1	3.6	3.8	3.8	4.3	3.6	3.5	3.8	4.2	3.6	15.6	15.5	15.1
Large-Scale Solar (b)	13.3	21.8	22.6	13.9	17.0	26.0	28.2	17.9	22.1	34.5	36.9	23.3	71.5	89.1	116.9
Wind	74.2	78.6	66.2	80.8	85.7	87.8	72.0	94.2	103.3	101.6	83.7	104.2	299.8	339.7	392.9
Other Sectors (c)															
Biomass	7.4	7.3	7.6	7.4	7.4	7.3	7.6	7.4	7.3	7.3	7.6	7.4	29.7	29.7	29.6
Waste	0.8	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	2.8	2.8	2.8
Wood	6.7	6.6	6.9	6.6	6.7	6.6	6.9	6.6	6.6	6.6	6.9	6.6	26.8	26.9	26.8
Conventional Hydroelectric	0.3	0.4	0.3	0.3	0.4	0.4	0.3	0.3	0.4	0.4	0.3	0.3	1.3	1.3	1.3
Large-Scale Solar (b)	0.1	0.2	0.2	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.7	0.7	0.7
Small-Scale Solar (d)	6.9	10.4	10.6	7.1	8.5	12.4	12.2	8.4	9.4	14.0	14.3	9.9	35.0	41.5	47.6
Residential Sector	4.0	6.2	6.4	4.3	5.1	7.5	7.5	5.1	5.7	8.6	8.8	6.1	20.9	25.2	29.2
Commercial Sector	2.3	3.3	3.3	2.2	2.7	3.8	3.7	2.6	2.9	4.3	4.3	3.0	11.1	12.7	14.5
Industrial Sector	0.6	0.9	0.9	0.6	0.7	1.0	1.0	0.7	0.8	1.1	1.2	0.8	3.0	3.5	3.9
Wind	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.5	0.7

-- = no data available

Notes: The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

(a) Power plants larger than or equal to one megawatt in size that are operated by electric utilities or independent power producers.

(b) Solar thermal and photovoltaic generating units at power plants larger than or equal to one megawatt.

(c) Businesses or individual households not primarily engaged in electric power production for sale to the public, whose generating capacity is at least one megawatt (except for small-scale solar photovoltaic data, which consists of systems smaller than one megawatt).

(d) Solar photovoltaic systems smaller than one megawatt, as measured in alternating current.

Historical data: Latest data available from EIA databases supporting the Electric Power Monthly, DOE/EIA-0226.

Minor discrepancies with published historical data are due to independent rounding.

Projections: EIA-860M database, EIA-826 Solar PV database, and EIA Regional Short-Term Energy Model.

Table 9a. U.S. Macroeconomic Indicators and CO2 Emissions
U.S. Energy Information Administration | Short-Term Energy Outlook - May 2020

	2019				2020				2021				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2019	2020	2021
Macroeconomic															
Real Gross Domestic Product															
(billion chained 2012 dollars - SAAR)	18,927	19,022	19,121	19,222	19,048	17,627	17,617	17,885	18,532	19,108	19,455	19,682	19,073	18,044	19,194
Real Personal Consumption Expend.															
(billion chained 2012 dollars - SAAR)	13,103	13,250	13,353	13,414	13,301	12,018	12,266	12,640	12,989	13,371	13,590	13,788	13,280	12,556	13,435
Real Private Fixed Investment															
(billion chained 2012 dollars - SAAR)	3,349	3,337	3,330	3,326	3,305	2,943	2,780	2,780	2,901	3,040	3,151	3,226	3,336	2,952	3,080
Business Inventory Change															
(billion chained 2012 dollars - SAAR)	113	75	67	18	-34	-60	-356	-433	-172	23	169	222	68	-221	61
Real Government Expenditures															
(billion chained 2012 dollars - SAAR)	3,258	3,297	3,310	3,331	3,344	3,348	3,365	3,375	3,390	3,403	3,416	3,422	3,299	3,358	3,408
Real Exports of Goods & Services															
(billion chained 2012 dollars - SAAR)	2,554	2,517	2,523	2,536	2,504	2,386	2,384	2,422	2,522	2,594	2,650	2,684	2,533	2,424	2,613
Real Imports of Goods & Services															
(billion chained 2012 dollars - SAAR)	3,498	3,498	3,514	3,437	3,358	3,030	2,824	2,923	3,119	3,353	3,565	3,721	3,487	3,034	3,439
Real Disposable Personal Income															
(billion chained 2012 dollars - SAAR)	14,878	14,934	15,012	15,073	15,206	15,536	15,609	15,320	15,442	15,564	15,662	15,758	14,974	15,418	15,606
Non-Farm Employment															
(millions)	150.2	150.6	151.2	151.8	152.2	144.6	139.8	138.2	138.8	140.9	143.6	146.2	150.9	143.7	142.4
Civilian Unemployment Rate															
(percent)	3.9	3.6	3.6	3.5	3.8	8.7	10.1	10.6	10.0	8.8	7.4	6.2	3.7	8.3	8.1
Housing Starts															
(millions - SAAR)	1.21	1.26	1.28	1.44	1.47	0.98	0.95	1.02	1.07	1.13	1.17	1.22	1.30	1.10	1.15
Industrial Production Indices (Index, 2012=100)															
Total Industrial Production	109.8	109.2	109.5	109.6	107.4	96.2	91.2	89.5	92.5	95.8	98.0	99.4	109.5	96.1	96.4
Manufacturing	106.5	105.7	105.9	105.8	103.9	90.0	84.7	83.1	86.5	90.4	92.9	94.6	106.0	90.4	91.1
Food	115.1	115.3	114.6	116.0	116.8	119.3	121.0	121.2	121.3	121.4	121.6	121.8	115.3	119.6	121.5
Paper	94.2	91.8	92.6	93.6	94.1	86.5	82.3	80.7	81.4	82.8	84.1	84.8	93.0	85.9	83.3
Petroleum and Coal Products	106.3	104.9	106.7	104.8	105.5	102.0	92.8	91.6	94.2	97.1	98.5	99.8	105.7	98.0	97.4
Chemicals	101.4	99.9	100.6	100.2	99.2	97.2	97.4	98.1	99.6	101.4	102.5	103.5	100.5	98.0	101.8
Nonmetallic Mineral Products	119.7	119.0	119.7	119.1	120.5	105.4	97.9	96.4	98.1	100.2	103.6	106.9	119.4	105.0	102.2
Primary Metals	97.9	96.7	96.4	96.6	94.8	80.9	77.2	76.8	79.1	82.6	84.0	85.0	96.9	82.4	82.6
Coal-weighted Manufacturing (a)	106.9	105.6	106.0	106.3	106.3	94.8	90.0	88.8	91.1	94.1	96.4	98.1	106.2	95.0	94.9
Distillate-weighted Manufacturing (a)	98.5	97.9	98.3	98.5	98.3	89.5	84.9	83.9	85.6	87.8	89.7	91.1	98.3	89.1	88.6
Electricity-weighted Manufacturing (a)	106.5	105.3	105.6	105.9	105.0	93.8	89.9	89.3	91.8	94.8	96.7	98.2	105.8	94.5	95.4
Natural Gas-weighted Manufacturing (a)	108.7	107.7	108.0	108.2	108.0	98.4	93.9	93.3	95.7	98.8	100.6	102.1	108.1	98.4	99.3
Price Indexes															
Consumer Price Index (all urban consumers)															
(index, 1982-1984=1.00)	2.53	2.55	2.56	2.58	2.59	2.54	2.56	2.58	2.60	2.62	2.64	2.64	2.56	2.57	2.63
Producer Price Index: All Commodities															
(index, 1982=1.00)	2.01	2.00	1.99	2.00	1.97	1.90	1.91	1.93	1.95	1.98	1.99	1.99	2.00	1.93	1.98
Producer Price Index: Petroleum															
(index, 1982=1.00)	1.81	2.08	1.96	1.96	1.74	1.04	1.20	1.26	1.31	1.53	1.60	1.61	1.95	1.31	1.51
GDP Implicit Price Deflator															
(index, 2012=100)	111.5	112.2	112.7	113.0	113.5	113.8	114.2	114.6	115.0	115.5	115.9	116.2	112.3	114.0	115.7
Miscellaneous															
Vehicle Miles Traveled (b)															
(million miles/day)	8,297	9,333	9,289	8,899	7,978	6,912	8,547	8,552	8,036	9,041	9,067	8,804	8,957	8,000	8,740
Air Travel Capacity															
(Available ton-miles/day, thousands)	643	685	707	688	599	494	706	676	679	715	754	743	681	619	723
Aircraft Utilization															
(Revenue ton-miles/day, thousands)	380	426	427	406	334	221	374	375	395	436	446	429	410	326	427
Airline Ticket Price Index															
(index, 1982-1984=100)	255.7	278.3	263.8	263.8	250.8	211.6	176.3	175.5	175.9	187.5	181.1	189.3	265.4	203.6	183.4
Raw Steel Production															
(million short tons per day)	0.273	0.271	0.264	0.265	0.268	0.179	0.227	0.265	0.263	0.255	0.251	0.253	0.268	0.235	0.256
Carbon Dioxide (CO2) Emissions (million metric tons)															
Petroleum	575	587	597	596	553	441	536	558	544	562	582	583	2,354	2,088	2,270
Natural Gas	507	350	384	448	496	354	365	412	462	341	354	416	1,689	1,628	1,573
Coal	289	239	307	242	209	181	238	204	226	202	271	218	1,076	832	917
Total Energy (c)	1,374	1,178	1,291	1,288	1,261	979	1,142	1,177	1,235	1,107	1,210	1,220	5,130	4,559	4,771

\- = no data available
SAAR = Seasonally-adjusted annual rate
(a) Fuel share weights of individual sector indices based on EIA *Manufacturing Energy Consumption Survey* .
(b) Total highway travel includes gasoline and diesel fuel vehicles.
(c) Includes electric power sector use of geothermal energy and non-biomass waste.
Notes: The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.
Historical data: Latest data available from U.S. Department of Commerce, Bureau of Economic Analysis; Federal Reserve System, Statistical release G17; Federal Highway Administration; and Federal Aviation Administration. Minor discrepancies with published historical data are due to independent rounding.
Projections: EIA Regional Short-Term Energy Model. U.S. macroeconomic projections are based on the IHS Markit model of the U.S. Economy.

Table 9b. U.S. Regional Macroeconomic Data
U.S. Energy Information Administration | Short-Term Energy Outlook - May 2020

	2019				2020				2021				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2019	2020	2021
Real Gross State Product (Billion $2009)															
New England	**996**	**999**	**1,004**	**1,009**	**997**	*919*	*920*	*935*	*969*	*998*	*1,018*	*1,031*	**1,002**	*943*	*1,004*
Middle Atlantic	**2,772**	**2,782**	**2,791**	**2,802**	**2,773**	*2,548*	*2,551*	*2,596*	*2,701*	*2,790*	*2,847*	*2,886*	**2,787**	*2,617*	*2,806*
E. N. Central	**2,528**	**2,535**	**2,545**	**2,557**	**2,530**	*2,337*	*2,338*	*2,377*	*2,452*	*2,526*	*2,568*	*2,592*	**2,541**	*2,395*	*2,535*
W. N. Central	**1,181**	**1,187**	**1,193**	**1,198**	**1,187**	*1,108*	*1,109*	*1,124*	*1,161*	*1,194*	*1,214*	*1,226*	**1,190**	*1,132*	*1,199*
S. Atlantic	**3,353**	**3,367**	**3,383**	**3,403**	**3,376**	*3,130*	*3,128*	*3,178*	*3,300*	*3,406*	*3,472*	*3,515*	**3,376**	*3,203*	*3,423*
E. S. Central	**832**	**835**	**840**	**844**	**836**	*777*	*778*	*790*	*818*	*843*	*857*	*865*	**838**	*795*	*846*
W. S. Central	**2,347**	**2,370**	**2,392**	**2,406**	**2,384**	*2,205*	*2,177*	*2,201*	*2,272*	*2,338*	*2,374*	*2,399*	**2,379**	*2,242*	*2,346*
Mountain	**1,252**	**1,261**	**1,269**	**1,277**	**1,265**	*1,168*	*1,168*	*1,183*	*1,227*	*1,266*	*1,294*	*1,312*	**1,265**	*1,196*	*1,275*
Pacific	**3,700**	**3,719**	**3,739**	**3,761**	**3,733**	*3,467*	*3,478*	*3,534*	*3,666*	*3,780*	*3,846*	*3,891*	**3,730**	*3,553*	*3,796*
Industrial Output, Manufacturing (Index, Year 2012=100)															
New England	**99.4**	**98.6**	**98.8**	**98.8**	**96.1**	*82.4*	*77.6*	*76.0*	*79.3*	*83.0*	*85.5*	*87.1*	**98.9**	*83.0*	*83.7*
Middle Atlantic	**99.1**	**98.2**	**98.1**	**98.1**	**96.3**	*83.7*	*78.7*	*77.0*	*80.3*	*83.6*	*85.9*	*87.3*	**98.4**	*83.9*	*84.3*
E. N. Central	**108.4**	**107.1**	**107.0**	**106.7**	**104.5**	*89.4*	*83.6*	*81.7*	*84.4*	*88.0*	*90.4*	*92.1*	**107.3**	*89.8*	*88.7*
W. N. Central	**106.0**	**105.2**	**105.3**	**105.2**	**103.0**	*89.1*	*84.2*	*82.9*	*86.7*	*90.7*	*93.3*	*95.0*	**105.4**	*89.8*	*91.4*
S. Atlantic	**111.0**	**110.3**	**110.8**	**111.1**	**109.0**	*94.7*	*88.8*	*86.9*	*90.5*	*94.4*	*97.1*	*98.8*	**110.8**	*94.8*	*95.2*
E. S. Central	**110.8**	**109.8**	**110.2**	**110.0**	**107.8**	*93.0*	*87.1*	*85.1*	*88.0*	*91.6*	*94.3*	*96.2*	**110.2**	*93.3*	*92.5*
W. S. Central	**101.7**	**101.1**	**101.4**	**101.5**	**100.2**	*87.4*	*82.1*	*80.2*	*83.7*	*87.5*	*89.8*	*91.3*	**101.4**	*87.5*	*88.1*
Mountain	**116.5**	**115.8**	**116.6**	**116.2**	**114.6**	*100.1*	*94.8*	*93.1*	*97.2*	*101.5*	*104.5*	*106.2*	**116.3**	*100.7*	*102.3*
Pacific	**105.1**	**104.2**	**104.1**	**104.3**	**102.7**	*88.8*	*84.3*	*83.1*	*87.0*	*91.1*	*93.8*	*95.4*	**104.4**	*89.7*	*91.8*
Real Personal Income (Billion $2009)															
New England	**904**	**905**	**901**	**904**	**911**	*902*	*903*	*892*	*902*	*914*	*925*	*935*	**903**	*902*	*919*
Middle Atlantic	**2,302**	**2,315**	**2,312**	**2,317**	**2,333**	*2,311*	*2,311*	*2,277*	*2,309*	*2,341*	*2,366*	*2,388*	**2,312**	*2,308*	*2,351*
E. N. Central	**2,428**	**2,432**	**2,442**	**2,454**	**2,467**	*2,470*	*2,466*	*2,420*	*2,437*	*2,465*	*2,491*	*2,516*	**2,439**	*2,456*	*2,477*
W. N. Central	**1,146**	**1,147**	**1,162**	**1,166**	**1,171**	*1,172*	*1,167*	*1,147*	*1,156*	*1,168*	*1,183*	*1,198*	**1,155**	*1,164*	*1,176*
S. Atlantic	**3,214**	**3,231**	**3,241**	**3,256**	**3,287**	*3,319*	*3,315*	*3,244*	*3,274*	*3,313*	*3,355*	*3,396*	**3,235**	*3,291*	*3,334*
E. S. Central	**887**	**890**	**894**	**899**	**907**	*918*	*920*	*898*	*905*	*915*	*923*	*931*	**893**	*911*	*918*
W. S. Central	**1,985**	**1,993**	**2,005**	**2,015**	**2,034**	*2,032*	*2,023*	*1,984*	*2,005*	*2,027*	*2,046*	*2,066*	**1,999**	*2,018*	*2,036*
Mountain	**1,168**	**1,177**	**1,188**	**1,193**	**1,202**	*1,203*	*1,202*	*1,180*	*1,192*	*1,208*	*1,224*	*1,240*	**1,181**	*1,197*	*1,216*
Pacific	**2,807**	**2,834**	**2,828**	**2,842**	**2,865**	*2,848*	*2,848*	*2,807*	*2,843*	*2,883*	*2,921*	*2,956*	**2,828**	*2,842*	*2,901*
Households (Thousands)															
New England	**5,936**	**5,941**	**5,957**	**5,966**	**5,972**	*5,972*	*5,971*	*5,972*	*5,973*	*5,976*	*5,985*	*5,997*	**5,966**	*5,972*	*5,997*
Middle Atlantic	**16,243**	**16,263**	**16,305**	**16,328**	**16,343**	*16,341*	*16,337*	*16,341*	*16,344*	*16,352*	*16,376*	*16,409*	**16,328**	*16,341*	*16,409*
E. N. Central	**19,087**	**19,112**	**19,166**	**19,197**	**19,221**	*19,230*	*19,233*	*19,246*	*19,255*	*19,267*	*19,299*	*19,342*	**19,197**	*19,246*	*19,342*
W. N. Central	**8,688**	**8,708**	**8,740**	**8,760**	**8,776**	*8,782*	*8,787*	*8,797*	*8,803*	*8,813*	*8,833*	*8,857*	**8,760**	*8,797*	*8,857*
S. Atlantic	**25,689**	**25,762**	**25,877**	**25,965**	**26,046**	*26,098*	*26,144*	*26,201*	*26,257*	*26,320*	*26,406*	*26,510*	**25,965**	*26,201*	*26,510*
E. S. Central	**7,651**	**7,663**	**7,689**	**7,706**	**7,720**	*7,726*	*7,730*	*7,739*	*7,745*	*7,754*	*7,772*	*7,794*	**7,706**	*7,739*	*7,794*
W. S. Central	**14,813**	**14,856**	**14,923**	**14,974**	**15,020**	*15,052*	*15,082*	*15,119*	*15,155*	*15,196*	*15,252*	*15,314*	**14,974**	*15,119*	*15,314*
Mountain	**9,404**	**9,448**	**9,506**	**9,551**	**9,593**	*9,624*	*9,652*	*9,683*	*9,712*	*9,742*	*9,781*	*9,825*	**9,551**	*9,683*	*9,825*
Pacific	**18,903**	**18,932**	**18,994**	**19,034**	**19,070**	*19,090*	*19,111*	*19,147*	*19,182*	*19,220*	*19,275*	*19,336*	**19,034**	*19,147*	*19,336*
Total Non-farm Employment (Millions)															
New England	**7.5**	**7.5**	**7.5**	**7.5**	**7.6**	*7.2*	*6.9*	*6.9*	*6.9*	*7.0*	*7.1*	*7.3*	**7.5**	*7.1*	*7.1*
Middle Atlantic	**20.0**	**20.0**	**20.1**	**20.1**	**20.2**	*19.1*	*18.4*	*18.3*	*18.4*	*18.6*	*19.0*	*19.3*	**20.0**	*19.0*	*18.8*
E. N. Central	**22.3**	**22.3**	**22.3**	**22.3**	**22.3**	*21.2*	*20.5*	*20.3*	*20.3*	*20.6*	*21.0*	*21.3*	**22.3**	*21.1*	*20.8*
W. N. Central	**10.8**	**10.8**	**10.8**	**10.8**	**10.8**	*10.4*	*10.1*	*10.0*	*10.0*	*10.1*	*10.3*	*10.4*	**10.8**	*10.3*	*10.2*
S. Atlantic	**29.0**	**29.1**	**29.2**	**29.3**	**29.4**	*27.9*	*26.9*	*26.6*	*26.8*	*27.3*	*27.9*	*28.4*	**29.1**	*27.7*	*27.6*
E. S. Central	**8.3**	**8.3**	**8.3**	**8.3**	**8.4**	*8.0*	*7.7*	*7.6*	*7.7*	*7.8*	*7.9*	*8.0*	**8.3**	*7.9*	*7.9*
W. S. Central	**17.6**	**17.7**	**17.8**	**17.9**	**18.0**	*17.2*	*16.5*	*16.3*	*16.3*	*16.6*	*16.8*	*17.1*	**17.8**	*17.0*	*16.7*
Mountain	**11.0**	**11.0**	**11.1**	**11.2**	**11.2**	*10.6*	*10.3*	*10.1*	*10.2*	*10.4*	*10.6*	*10.9*	**11.1**	*10.6*	*10.5*
Pacific	**23.6**	**23.7**	**23.9**	**24.0**	**24.1**	*22.9*	*22.2*	*21.9*	*22.0*	*22.3*	*22.8*	*23.2*	**23.8**	*22.8*	*22.6*

- = no data available

Notes: The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Regions refer to U.S. Census divisions.

See "Census division" in EIA’s Energy Glossary (http://www.eia.doe.gov/glossary/index.html) for a list of States in each region.

Historical data: Latest data available from U.S. Department of Commerce, Bureau of Economic Analysis; Federal Reserve System, Statistical release G17.

Minor discrepancies with published historical data are due to independent rounding.

Projections: Macroeconomic projections are based on the IHS Markit model of the U.S. Economy.

Table 9c. U.S. Regional Weather Data

U.S. Energy Information Administration | Short-Term Energy Outlook - May 2020

	2019				2020				2021				Year		
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2019	2020	2021
Heating Degree Days															
New England	3,226	896	136	2,280	2,724	893	125	2,162	3,169	881	129	2,162	6,537	5,904	6,341
Middle Atlantic	2,987	634	68	2,066	2,471	715	78	1,983	2,931	704	77	1,983	5,755	5,247	5,695
E. N. Central	3,328	762	65	2,279	2,788	804	115	2,228	3,151	732	116	2,228	6,434	5,934	6,227
W. N. Central	3,645	772	107	2,548	3,035	775	152	2,407	3,237	700	152	2,407	7,072	6,369	6,497
South Atlantic	1,334	128	2	918	1,105	215	12	951	1,378	183	12	950	2,382	2,283	2,523
E. S. Central	1,713	193	1	1,273	1,484	303	19	1,284	1,783	231	19	1,284	3,181	3,089	3,317
W. S. Central	1,208	90	0	852	973	116	4	763	1,103	77	4	763	2,151	1,856	1,947
Mountain	2,431	786	127	1,965	2,218	687	137	1,798	2,186	690	139	1,797	5,309	4,840	4,812
Pacific	1,690	578	96	1,184	1,538	513	80	1,170	1,497	578	83	1,171	3,547	3,301	3,329
U.S. Average	2,211	481	57	1,559	1,875	505	69	1,506	2,094	483	70	1,504	4,307	3,956	4,151
Heating Degree Days, Prior 10-year Average															
New England	3,166	820	111	2,122	3,152	823	105	2,128	3,132	848	108	2,116	6,218	6,207	6,204
Middle Atlantic	2,956	650	76	1,941	2,949	644	69	1,945	2,913	665	71	1,927	5,623	5,606	5,576
E. N. Central	3,196	697	112	2,198	3,198	698	102	2,197	3,157	727	104	2,183	6,203	6,195	6,170
W. N. Central	3,255	702	140	2,380	3,287	702	131	2,379	3,247	726	131	2,377	6,477	6,500	6,480
South Atlantic	1,480	176	11	964	1,459	169	10	951	1,393	177	10	922	2,631	2,589	2,501
E. S. Central	1,861	222	17	1,292	1,850	214	15	1,277	1,772	228	16	1,255	3,392	3,356	3,270
W. S. Central	1,183	85	4	808	1,199	83	3	794	1,140	87	3	789	2,079	2,079	2,019
Mountain	2,164	714	139	1,856	2,193	718	135	1,844	2,182	703	135	1,846	4,873	4,890	4,866
Pacific	1,444	582	83	1,175	1,456	580	85	1,162	1,462	551	82	1,156	3,283	3,284	3,251
U.S. Average	2,151	475	68	1,518	2,149	472	64	1,509	2,108	478	64	1,493	4,212	4,194	4,144
Cooling Degree Days															
New England	0	67	465	0	0	98	427	1	0	80	405	1	532	527	487
Middle Atlantic	0	145	629	8	0	168	553	4	0	150	540	4	782	725	695
E. N. Central	0	175	649	6	2	213	541	7	0	217	542	7	830	764	767
W. N. Central	0	223	728	2	6	254	670	11	3	266	675	11	954	941	955
South Atlantic	152	756	1,297	308	198	697	1,173	235	128	674	1,180	235	2,513	2,302	2,217
E. S. Central	28	548	1,215	87	72	490	1,047	68	30	539	1,063	68	1,878	1,677	1,699
W. S. Central	73	821	1,695	169	174	905	1,517	211	97	888	1,522	211	2,757	2,807	2,718
Mountain	10	342	985	60	9	439	949	79	19	426	941	79	1,396	1,476	1,465
Pacific	21	166	588	68	24	178	598	59	27	168	587	59	842	860	842
U.S. Average	45	399	952	105	71	416	864	96	46	409	864	96	1,501	1,447	1,415
Cooling Degree Days, Prior 10-year Average															
New England	0	79	455	1	0	83	470	1	0	80	462	1	536	554	543
Middle Atlantic	0	165	589	6	0	170	609	6	0	164	597	6	760	785	767
E. N. Central	3	242	548	7	3	240	578	8	3	234	565	7	799	829	809
W. N. Central	7	298	669	11	7	296	697	11	7	290	687	11	985	1,011	995
South Atlantic	120	684	1,180	239	127	696	1,202	247	143	688	1,190	254	2,224	2,272	2,275
E. S. Central	36	555	1,049	67	36	557	1,082	72	42	538	1,063	73	1,706	1,746	1,716
W. S. Central	103	897	1,552	205	100	892	1,576	207	114	887	1,569	210	2,758	2,775	2,780
Mountain	25	438	932	81	24	432	939	81	24	442	940	82	1,476	1,476	1,488
Pacific	31	185	631	76	31	185	624	78	31	191	636	79	923	918	936
U.S. Average	46	417	873	97	47	420	892	100	52	417	887	102	1,433	1,459	1,458

\- = no data available

Notes: Regional degree days for each period are calculated by EIA as contemporaneous period population-weighted averages of state degree day data published by the National Oceanic and Atmospheric Administration (NOAA).

See *Change in Regional and U.S. Degree-Day Calculations* (http://www.eia.gov/forecasts/steo/special/pdf/2012_sp_04.pdf) for more information.

The approximate break between historical and forecast values is shown with historical data printed in bold; estimates and forecasts in italics.

Regions refer to U.S. Census divisions. See "Census division" in EIA's Energy Glossary (http://www.eia.gov/tools/glossary/) for a list of states in each region.

Historical data: Latest data available from U.S. Department of Commerce, National Oceanic and Atmospheric Association (NOAA).

Projections: Based on forecasts by the NOAA Climate Prediction Center (http://www.cpc.ncep.noaa.gov/pacdir/DDdir/NHOME3.shtml).

Annual Energy Outlook 2020

with projections to 2050

#AEO2020

January 29, 2020
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Office of Energy Analysis
U.S. Department of Energy
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Key Takeaways from U.S. Energy Information Administration's *Annual Energy Outlook 2020*

- In the U.S. Energy Information Administration's (EIA) *Annual Energy Outlook 2020* (AEO2020) Reference case, U.S. energy consumption grows more slowly than gross domestic product throughout the projection period (2050) as U.S. energy efficiency continues to increase. This decline in the energy intensity of the U.S. economy continues through 2050.

- The electricity generation mix continues to experience a rapid rate of change, with renewables the fastest-growing source of electricity generation through 2050 because of continuing declines in the capital costs for solar and wind that are supported by federal tax credits and higher state-level renewables targets. With slow load growth and increasing electricity production from renewables, U.S. coal-fired and nuclear electricity generation declines; most of the decline occurs by the mid-2020s.

- The United States continues to produce historically high levels of crude oil and natural gas. Slow growth in domestic consumption of these fuels leads to increasing exports of crude oil, petroleum products, and liquefied natural gas.

- After falling during the first half of the projection period, total U.S. energy-related carbon dioxide emissions resume modest growth in the 2030s, driven largely by increases in energy demand in the transportation and industrial sectors; however, by 2050, they remain 4% lower than 2019 levels.

The Annual Energy Outlook explores long-term energy trends in the United States

- The value of the projections in the AEO2020 is not that they are predictions of what will happen, but rather, they are modeled projections of what may happen given certain assumptions and methodologies. By varying those assumptions and methodologies, AEO2020 can illustrate important factors in future energy production and use in the United States.

- Energy market projections are subject to much uncertainty because many of the events that shape energy markets—as well as future developments in technologies, demographics, and resources—cannot be foreseen with certainty. To illustrate the importance of key assumptions, AEO2020 includes a Reference case and side cases that systematically vary important underlying assumptions.

- EIA develops the AEO with the National Energy Modeling System (NEMS), an integrated model that captures interactions of economic changes and energy supply, demand, and prices.

- More information about the assumptions EIA used to develop these projections will be available on the AEO website shortly after the release of the AEO2020.

- The AEO is published to satisfy the Department of Energy Organization Act of 1977, which requires the Administrator of the U.S. Energy Information Administration to prepare annual reports on trends and projections for energy use and supply.

What is the AEO2020 Reference case?

- The AEO2020 Reference case represents EIA's best assessment of how U.S. and world energy markets will operate through 2050, based on key assumptions intended to provide a base for exploring long-term trends.
- The AEO2020 Reference case should be interpreted as a reasonable baseline case that can be compared with the cases that include alternative assumptions.
- EIA based the economic and demographic trends reflected in the Reference case on the current views of leading economic forecasters and demographers. For example, the Reference case projection assumes improvement in known energy production, delivery, and consumption technologies.
- The Reference case generally assumes that current laws and regulations that affect the energy sector, including laws that have end dates, are unchanged throughout the projection period. This assumption makes it possible for us to use the Reference case as a benchmark to compare policy-based modeling.
- The potential effects of proposed legislation, regulations, or standards are not included in the AEO2020 cases.

What are the side cases?

- Oil prices in the future will be driven by global market balances that are primarily influenced by factors that are not modeled in NEMS. In the AEO2020 High Oil Price case, the price of Brent crude oil, in 2019 dollars, reaches $183 per barrel (b) by 2050, compared with $105/b in the Reference case and $46/b in the Low Oil Price case.
- Compared with the Reference case, the High Oil and Gas Supply case reflects lower costs and greater U.S. oil and natural gas resource availability, which allows more production at lower prices. The Low Oil and Gas Supply case assumes fewer resources and higher costs.
- The effects of economic assumptions on the energy consumption modeled in the AEO2020 are addressed in the High Economic Growth and Low Economic Growth cases, which assume compound annual growth rates for U.S. gross domestic product of 2.4% and 1.4%, respectively, from 2019 to 2050, compared with 1.9% per year growth in the Reference case.
- AEO2020 introduces two cases to examine the sensitivities surrounding capital costs for electric power generating technologies. Capital cost reduction for an electric power generating technology is assumed to occur from learning by doing. In the High Renewables Cost case, no cost reduction from learning is assumed for any renewable technologies. The Low Renewables Cost case assumes higher learning for renewable technologies through 2050, resulting in a cost reduction of about 40% from the Reference case by 2050.

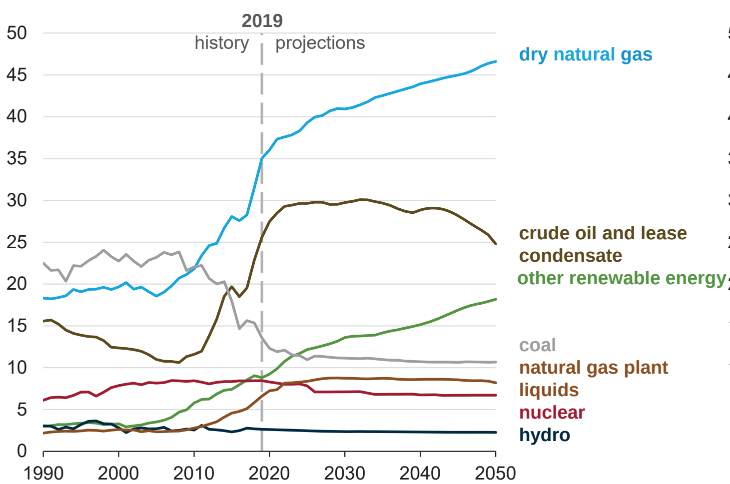
Table of contents

Overview of energy markets

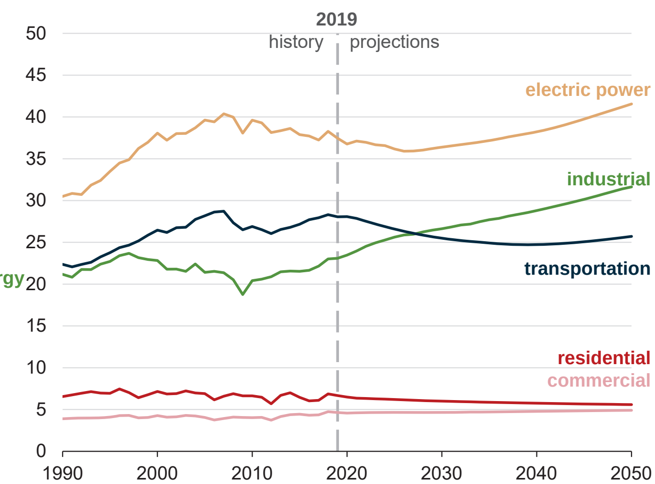
In the Reference case, strong domestic energy production coupled with slow growth in domestic energy demand leads the United States to remain a net energy exporter through 2050. Energy-related carbon dioxide emissions, driven by changes in the electricity generation fuel mix and increasing activity in the transportation and industrial sectors, experience modest growth in the later part of the projection period after falling in the 2020s.

U.S. energy production grows significantly, but consumption grows moderately under the AEO2020 Reference case assumption of current laws and regulations

Energy production (AEO2020 Reference case)
quadrillion British thermal units

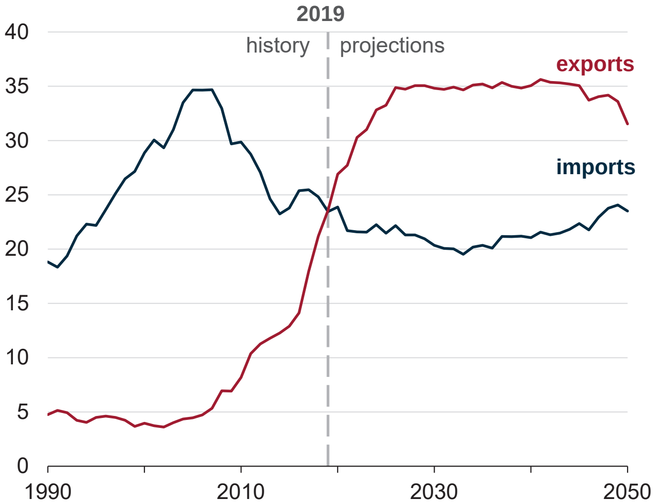


Energy consumption by sector (AEO2020 Reference case)
quadrillion British thermal units

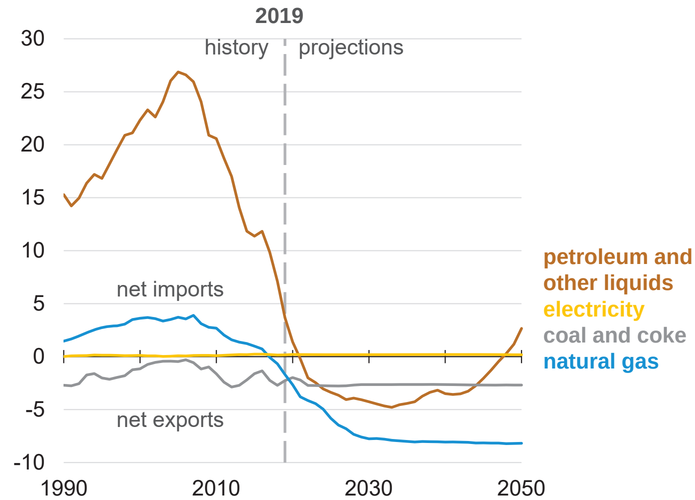


The United States becomes a net energy exporter on an annual basis by 2020 in the AEO2020 Reference case—

Gross energy trade (AEO2020 Reference case)
quadrillion British thermal units



Net energy imports (AEO2020 Reference case)
quadrillion British thermal units

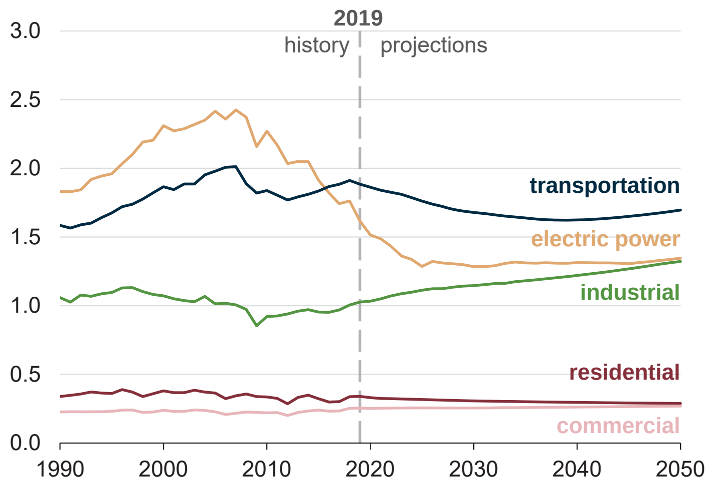


—but the United States continues to import and export energy throughout the projection period

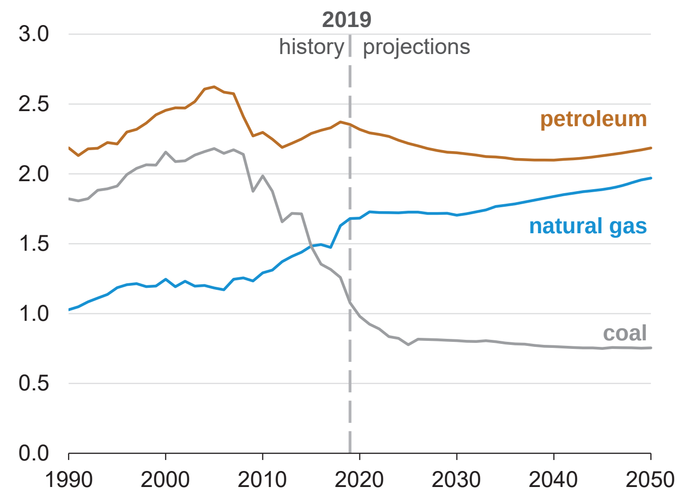
- The United States imported more energy than it exported annually since 1953, but continued growth in petroleum and natural gas exports results in the United States becoming a net energy exporter in 2020 in all AEO2020 cases.
- In the AEO2020 Reference case, the United States exports more petroleum and other liquids than it imports annually starting in 2020 as U.S. crude oil production continues to increase and domestic consumption of petroleum products decreases. Near the end of the projection period, the United States returns to importing more petroleum and other liquids than it exports on an energy basis as a result of increasing domestic gasoline consumption and falling domestic crude oil production after 2047.
- The United States became a net natural gas exporter on an annual basis in 2017 and continued to export more natural gas than it imported in 2018 and in 2019. In the AEO2020 Reference case, liquefied natural gas (LNG) exports to more distant destinations will increasingly dominate the U.S. natural gas trade, and the United States is projected to remain a net natural gas exporter through 2050.
- The United States continues to be a net exporter of coal (including coal coke) through 2050 in the AEO2020 Reference case, but coal exports remain at the same level because of competition from other global suppliers that are closer to major world consumers.

AEO2020 energy-related carbon dioxide emissions increase in the industrial sector, increase as a result of natural gas consumption, but remain relatively flat in other sectors and fuels through 2050

Energy-related CO2 emissions by energy sector (AEO2020 Reference case)
billion metric tons



Energy-related CO2 emissions by fuel (AEO2020 Reference case)
billion metric tons



Critical drivers and model updates

Many factors influenced the results presented in AEO2020, including model improvements, new and existing laws and regulations since AEO2019, and varying assumptions about global oil prices, macroeconomic growth, domestic energy resources and production technology, and technology costs for renewable electricity generation.

Critical drivers and uncertainty

- Future oil prices are highly uncertain and are subject to international market conditions influenced by factors outside of the National Energy Modeling System. The High Oil Price and Low Oil Price cases represent international conditions that could drive prices to extreme, sustained deviations from the Reference case price path. In the High Oil Price case, non-U.S. demand for petroleum and other liquids is higher and non-U.S. supply of liquids is lower; in the Low Oil Price case, the opposite is true.

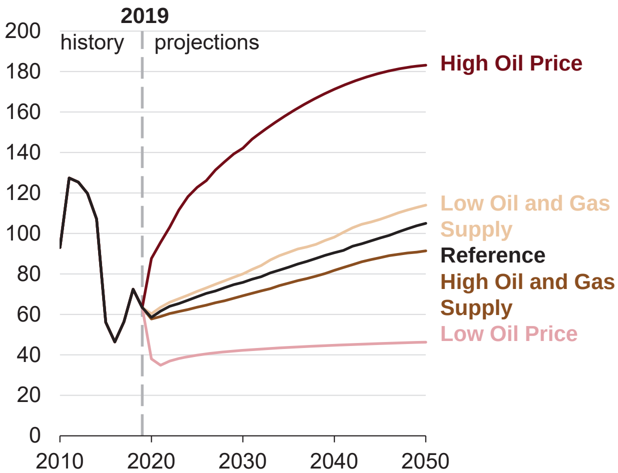
- Projections of tight oil and shale gas production are uncertain because large portions of known formations have relatively little or no production history and extraction technologies and practices continue to evolve rapidly. In the High Oil and Gas Supply case, lower production costs and higher resource availability allow higher production at lower prices. In the Low Oil and Gas Supply case, EIA applied assumptions of lower resources and higher production costs. EIA did not extend these assumptions to outside the United States.

- Economic growth drives energy consumption. The High Economic Growth and Low Economic Growth cases address these effects by modifying population growth and productivity assumptions throughout the projection period to yield higher or lower compound annual growth rates for U.S. gross domestic product (GDP).

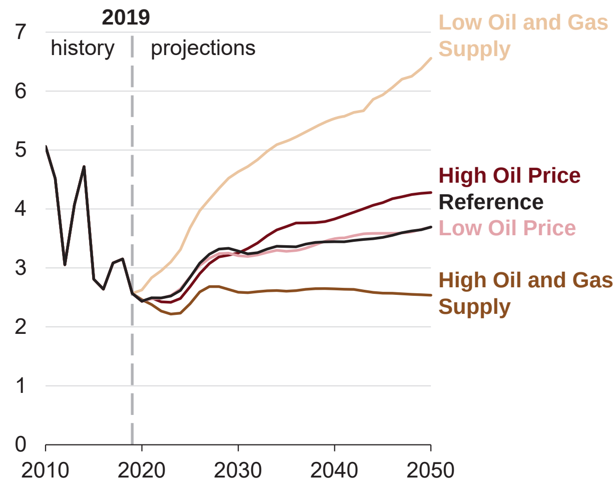
- Costs for renewables such as wind and solar have continued to decline as experience is gained with more builds. How long these high cost reduction rates can be sustained is highly uncertain. The High Renewables Cost case assumes no further cost reduction for renewables, and the Low Renewables Cost case assumes a sustained high rate of cost reduction. The Reference case assumes that cost reduction rates gradually taper off.

EIA develops oil and natural gas price assumptions by considering international supply and demand and the development of U.S. shale resources—

AEO2020 North Sea Brent crude oil price
2019 dollars per barrel



AEO2020 natural gas price at Henry Hub
2019 dollars per million British thermal unit



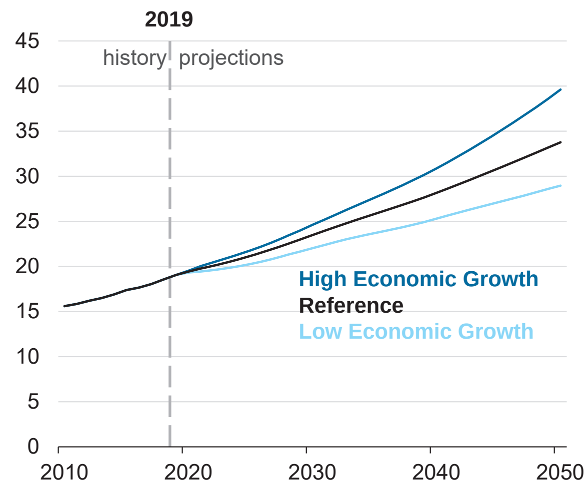
—however, global conditions are more important for oil prices and assumptions about resource and technology are more important for natural gas prices

- EIA's assumed crude oil prices in AEO2020 are influenced more by assessments of international markets than by assumptions about domestic resources and technological advances. In the High Oil Price case, EIA projects the price of Brent crude oil in 2019 dollars to reach $183 per barrel (b) by 2050 compared with $105/b in the Reference case and $46/b in the Low Oil Price case.

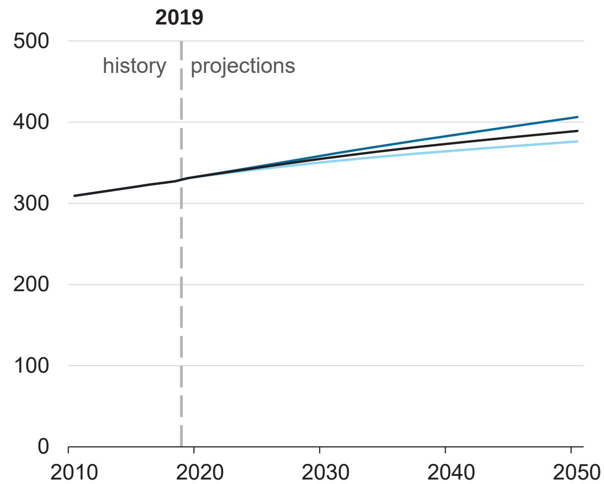
- Natural gas prices are highly sensitive to factors that drive supply, such as domestic resource and technology assumptions, and are less dependent on the international conditions that drive oil prices. In the High Oil and Gas Supply case, Henry Hub natural gas prices remain lower than $3 per million British thermal units ($/MMBtu) throughout the projection period, but in the Low Oil and Gas Supply case, they rise to more than $6/MMBtu during the same period.

Economic growth side cases explore the uncertainty in macroeconomic assumptions inherent in future economic growth trends—

AEO2020 gross domestic product assumptions
trillion 2012 dollars



AEO2020 U.S. population assumptions
millions



—which also affect important drivers of energy demand growth

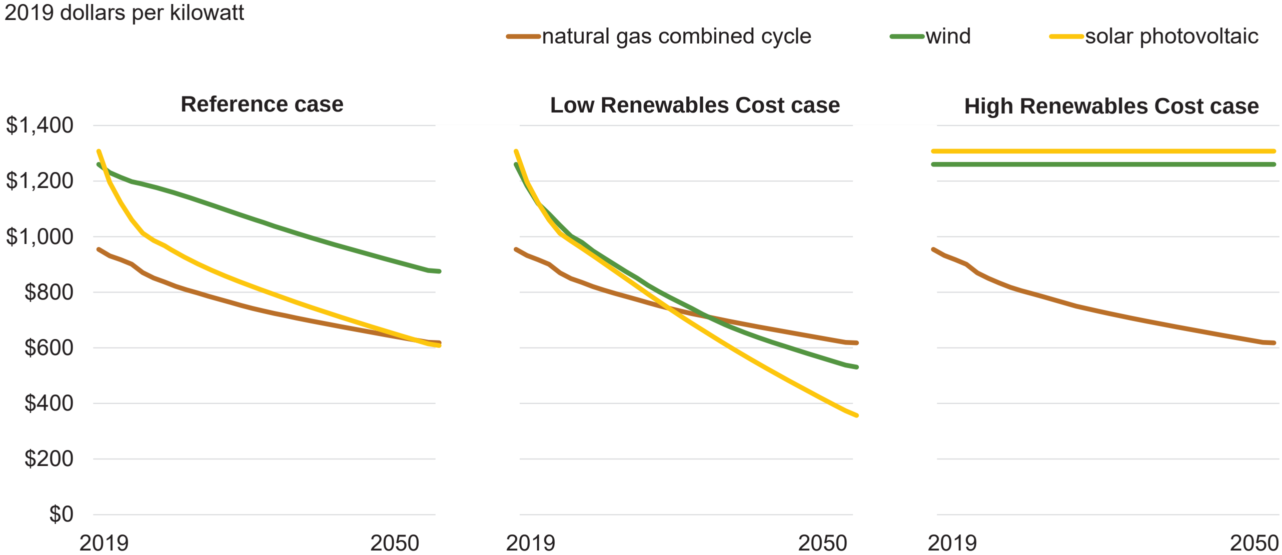
- The AEO2020 Reference, High Economic Growth, and Low Economic Growth cases illustrate three possible paths for U.S. economic growth. In the High Economic Growth case, average annual growth in real GDP during the projection period is 2.4%, compared with 1.9% in the Reference case. The Low Economic Growth case assumes a lower rate of annual growth in real GDP of 1.4%.

- Differences among the cases reflect different assumptions for growth in the labor force, capital stock, and productivity. These changes affect capital investment decisions, household formation, industrial activity, and amount of travel.

- All three economic growth cases assume smooth economic growth and do not anticipate business cycles or large economic shocks.

The High Renewables Cost and Low Renewables Cost cases assume different rates of cost reduction for renewable technologies compared with the Reference case; non-renewables assume the same rates

AEO2020 overnight installed cost by technology
2019 dollars per kilowatt

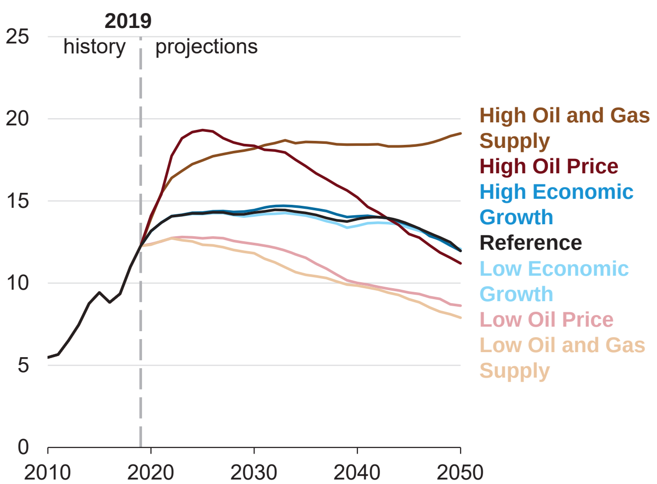


Petroleum and other liquids

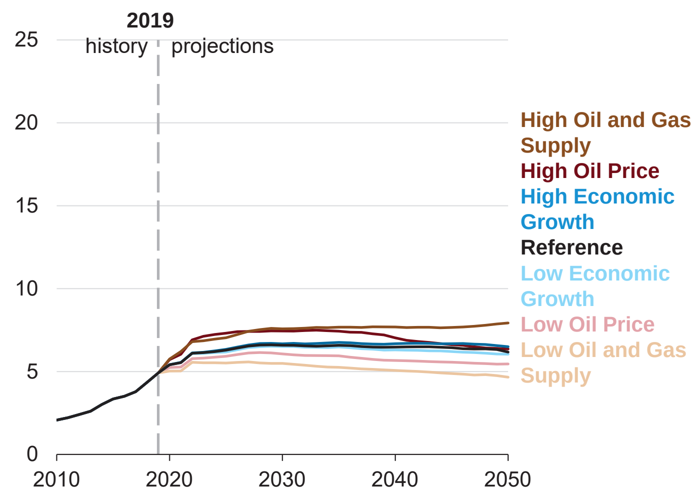
Growth in production of U.S. crude oil and natural gas plant liquids generally continues through 2025, mainly as a result of the continued development of tight oil resources. During the same period, domestic consumption falls, making the United States a net exporter of liquid fuels in the AEO2020 Reference case and in many of the side cases.

Production of U.S. crude oil and natural gas plant liquids continues to grow through 2025 in the AEO2020 Reference case—

AEO2020 U.S. crude oil production
million barrels per day



AEO2020 U.S. natural gas plant liquids production
million barrels per day



—and natural gas plant liquids comprise nearly one-third of cumulative U.S. liquids production during the projection period

- In the AEO2020 Reference case, U.S. crude oil production reaches 14.0 million barrels per day (b/d) by 2022 and remains near this level through 2045 as tight oil development moves into less productive areas and well productivity declines.

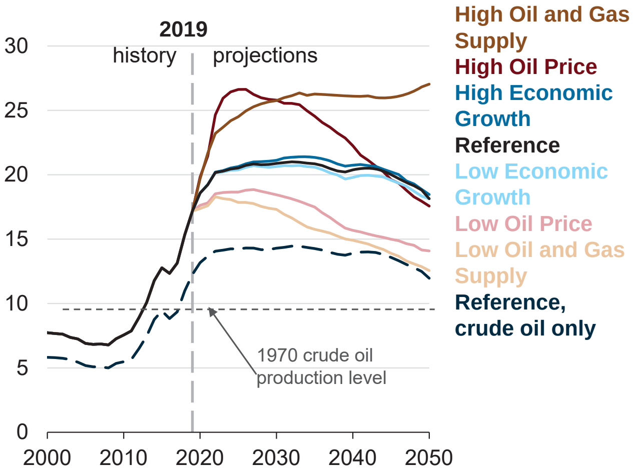
- The continued development of tight oil and shale gas resources in the AEO2020 Reference case supports growth in natural gas plant liquids (NGPL) production, which reaches 6.6 million b/d by 2028. NGPLs are light hydrocarbons predominantly found in natural gas wells and are diverted from the natural gas stream by natural gas processing plants. These hydrocarbons include ethane, propane, normal butane, isobutane, and natural gasoline.

- In the AEO2020 Reference case, NGPL production grows by 26% during the projection period as a result of demand increases by the global petrochemical industry. Most NGPL production growth in the AEO2020 Reference case occurs before 2025 as producers focus on natural gas plant liquids-rich plays, where NGPL-to-gas ratios are highest and increased demand spurs greater ethane recovery.

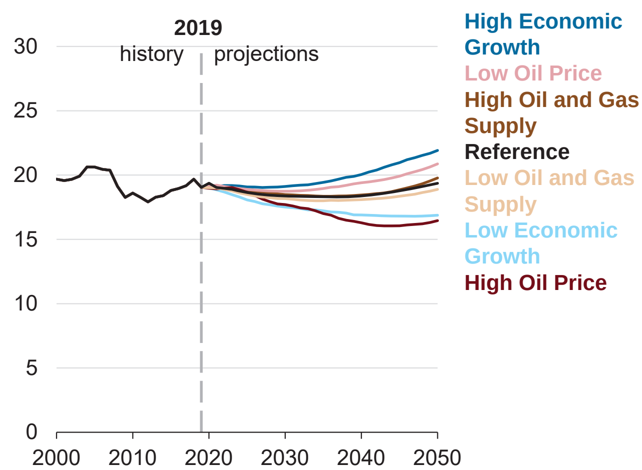
- In the AEO2020 cases, NGPL production is sensitive to changes in resource and technology assumptions, as well as oil price assumptions. In the High Oil and Gas Supply case, which has faster rates of technological improvement, higher recovery estimates, and additional tight oil and shale gas resources, NGPL production grows by 61% during the projection period. In the High Oil Price case, high crude oil prices lead to more drilling in the near term, but cost increases and fewer easily accessible resources decrease production of crude oil and NGPLs later in the forecast period.

Although production continues to grow through 2025, consumption of petroleum and other liquids remains lower than its 2004 peak level through 2050 in most cases

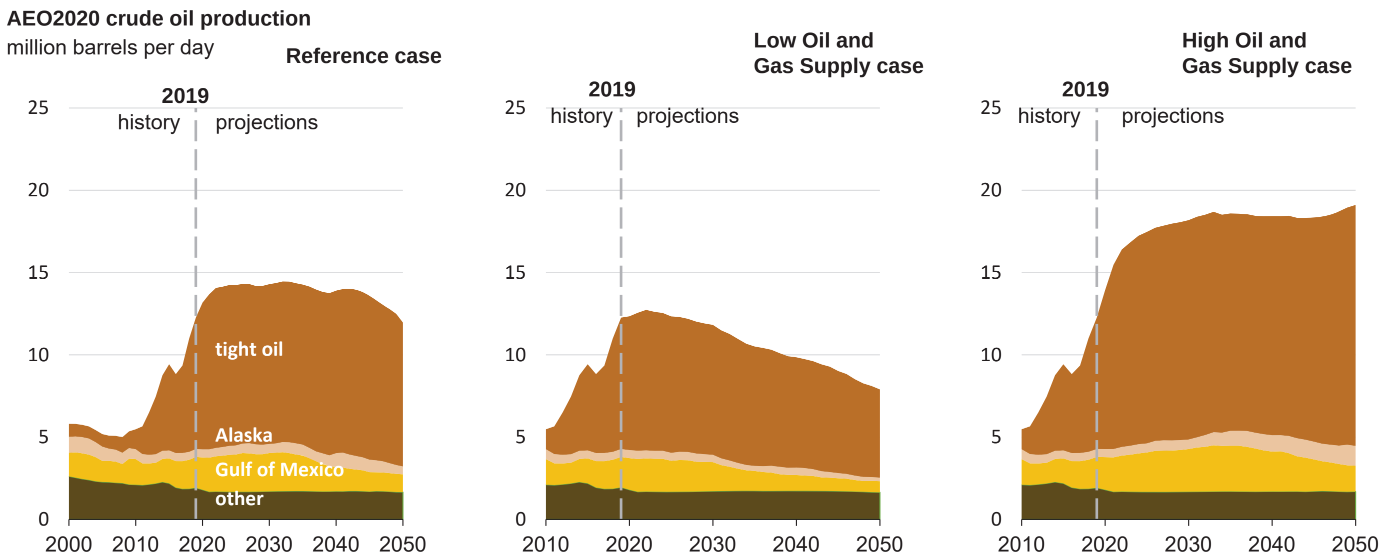
AEO2020 U.S. crude oil and natural gas plant liquids production
million barrels per day



AEO2020 petroleum and other liquids consumption
million barrels per day



Tight oil development drives U.S. crude oil production during the AEO2020 projection period—

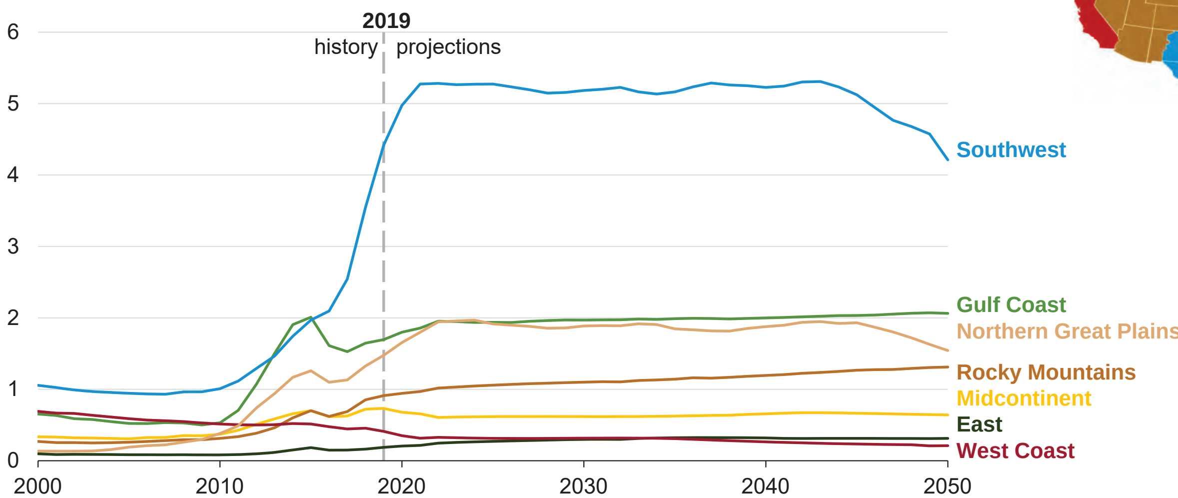


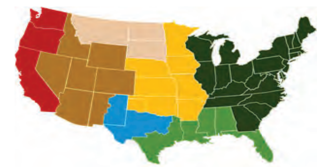
—which is consistent across all AEO2020 side cases

- Onshore tight oil development in the Lower 48 states continues to be the main driver of total U.S. crude oil production, accounting for about 70% of cumulative domestic production in the AEO2020 Reference case during the projection period.
- In the AEO2020 Reference case, deepwater discoveries of oil and natural gas resources in the Gulf of Mexico lead offshore production in the Lower 48 states to reach a record 2.4 million b/d in 2026. Many of these discoveries occurred during exploration that took place before 2015, when oil prices were higher than $100 per barrel, and they are being developed as oil prices rise. Offshore production increases through 2035 before generally declining through 2050 as a result of new discoveries only partially offsetting declines in legacy fields.
- Alaska crude oil production generally increases through 2041, driven primarily by the development of fields in the National Petroleum Reserve–Alaska (NPR-A) before 2030, and after 2030, by the development of fields in the 1002 Section of the Arctic National Wildlife Refuge (ANWR). Exploration and development of fields in ANWR is not economical in the Low Oil Price case.

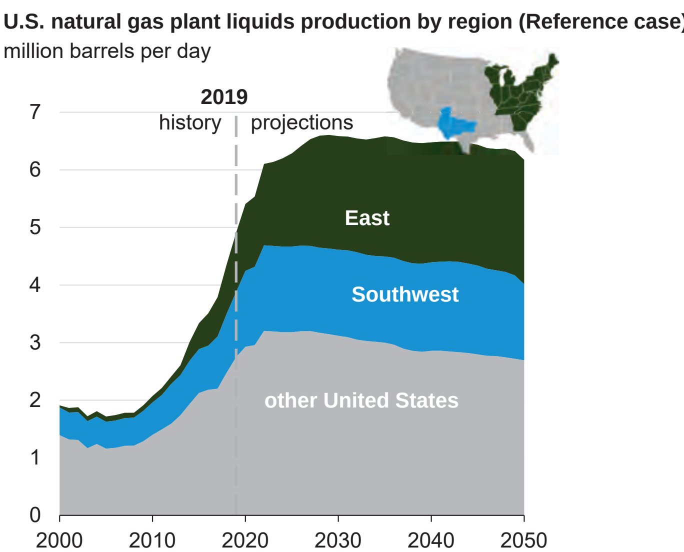
The Southwest region leads onshore crude oil production in the United States in the AEO2020 Reference case

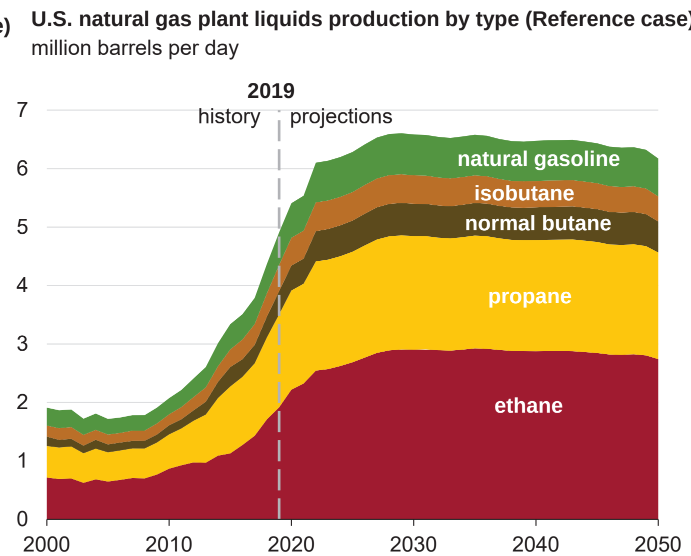
Onshore crude oil production in the Lower 48 states (AEO2020 Reference case)
million barrels per day





The East and Southwest regions lead production of natural gas plant liquids in the AEO2020 Reference case—





—as development focuses on tight plays with low production costs and easy access to markets

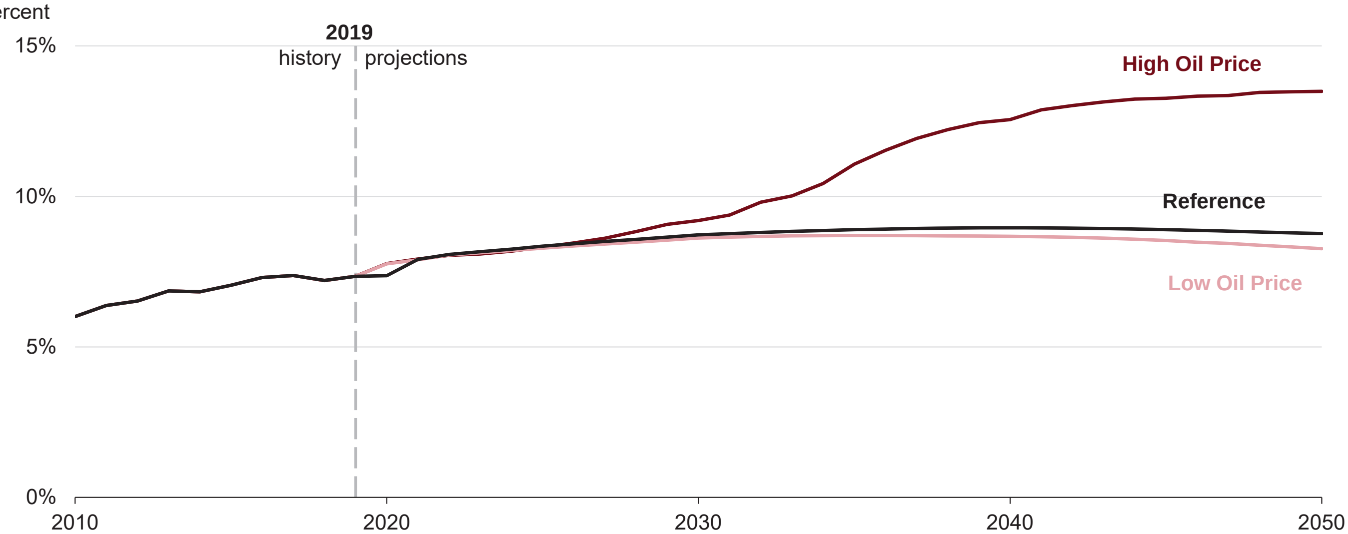
- NGPL production in the AEO2020 Reference case increases during the next 10 years in the East (Marcellus and Utica plays) and Southwest (Permian plays) regions because the development of crude oil and natural gas resources is driven in part by the increased economic favorability of coproducing these products. By 2050, the Southwest and East regions account for nearly 60% of total U.S. NGPL production.

- NGPLs are used in many different ways in the United States. Ethane is used almost exclusively for petrochemicals. About 40% of propane is used for petrochemicals, and the remainder is used for heating, grain drying, and transportation. About 60% of butanes and natural gasoline is used for blending with motor gasoline and fuel ethanol, and the remainder is used for petrochemicals and solvents.

- The shares of NGPL components in the AEO2020 Reference case are relatively stable during the entire projection period. Ethane and propane contribute about 44% and 30%, respectively, to the total volume.

Biofuels as a percentage of gasoline, diesel, and jet fuel consumption increase in the AEO2020 Reference case projection—

AEO2020 projected biofuel percentage of gasoline, distillate, and jet fuel consumption



—and biofuels adoption accelerates in the AEO2020 High Oil Price case as biofuels become more competitive

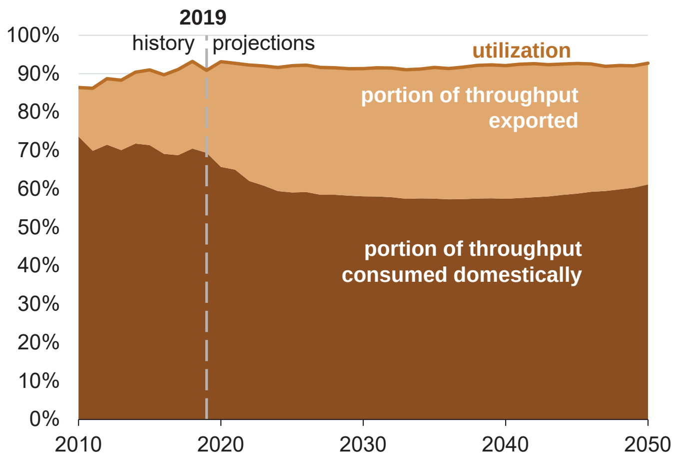
- EIA projects that the percentage of biofuels (ethanol, biodiesel, renewable diesel, and biobutanol) blended into U.S. gasoline, diesel, and jet fuel in the AEO2020 Reference case will increase from 7.3% in 2019 to peak at 9.0% in 2040.

- The share of biofuels consumed in the United States rises more in the AEO2020 High Oil Price case as higher prices for gasoline, diesel, and jet fuel make biofuels more competitive. In that case, the biofuels share rises to 13.5% in 2050.

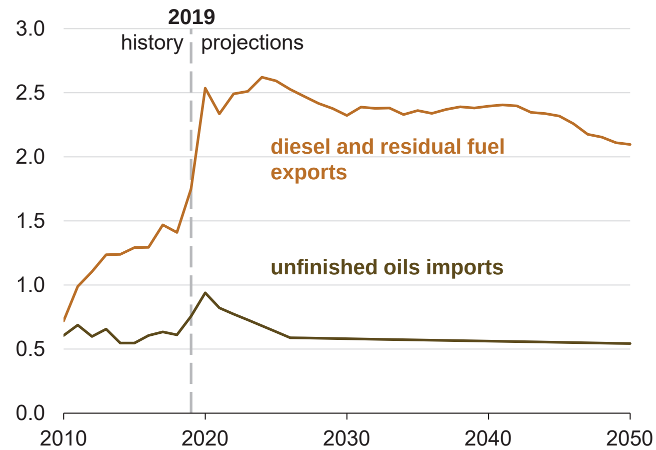
- In the AEO2020 Low Oil Price case, the share of biofuels consumed in the United States is relatively unchanged compared with the Reference Case because of federal and state regulations. Regulations such as the Renewable Fuel Standard and Low Carbon Fuel Standard support biofuels consumption when prices of petroleum-based product are low and biofuels are less competitive.

Utilization of U.S. refineries remains near recent levels throughout the projection period in the Reference case as U.S. refineries remain competitive in the global market—

U.S. refinery utilization (Reference case)
percent



U.S. diesel and residual fuel exports and unfinished oils imports (Reference case)
million barrels per day

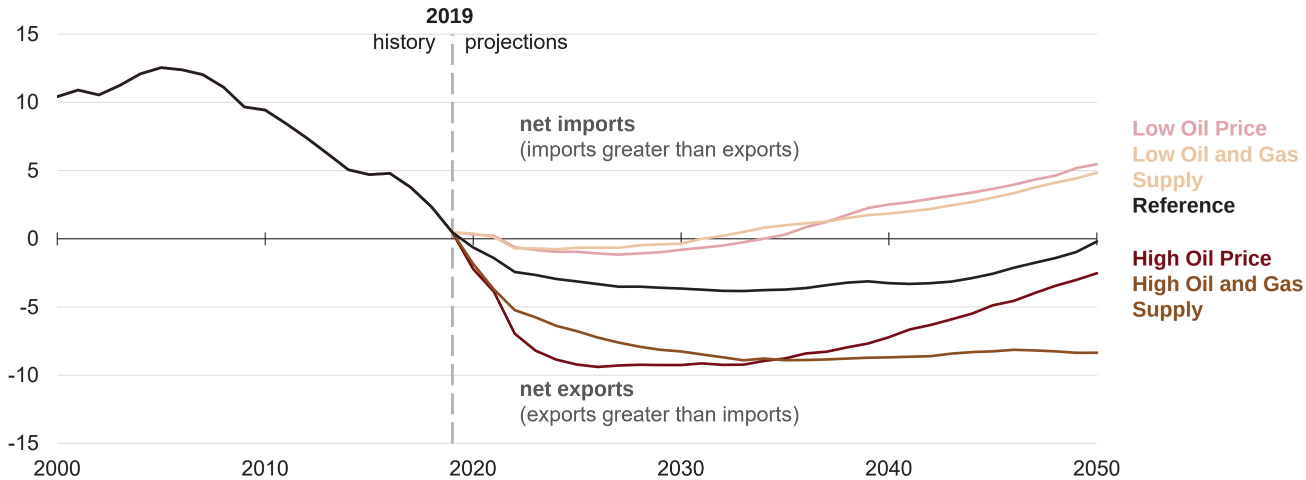


—and U.S. exports of low-sulfur diesel and residual fuel oil increase in 2020 as a result of international sulfur emissions regulations on the marine sector

- The share of U.S. refinery throughput that is exported increases in the AEO2020 Reference case as domestic consumption of refined products decreases, leaving more petroleum product available to export from 2020 to 2041. The trend reverses after 2041 when domestic consumption (especially of gasoline) gradually increases.
- The global competitiveness of the U.S. refining sector and the ability of the United States to increase exports as domestic consumption falls keep domestic refinery utilization near recent levels, between 90% and 93%, during the projection period in the Reference case.
- Imports of unfinished oils peak in 2020 as U.S. refineries take advantage of the increased discount of the heavy, high-sulfur residual fuel oil available on the global market. Exports of diesel and residual fuel (especially low-sulfur residual fuel) increase to 2.5 million barrels per day in 2020 because U.S. refineries are well -positioned to supply some of the increase in global demand for low-sulfur fuels as a result of the International Maritime Organization's new limits on sulfur content in marine fuels.

In the AEO2020 Reference case, the United States exports more petroleum on a volume basis than it imports from 2020 to 2050—

AEO2020 U.S. petroleum and other liquids trade
million barrels per day

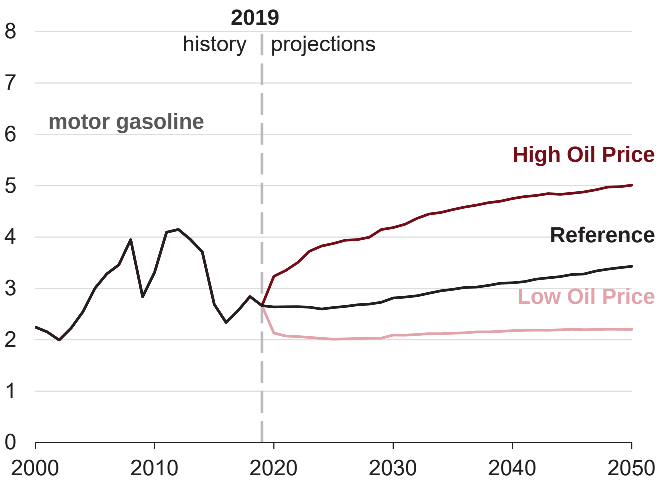


—but side case results vary significantly as shifts in U.S. domestic petroleum consumption and crude oil production drive changes to net imports

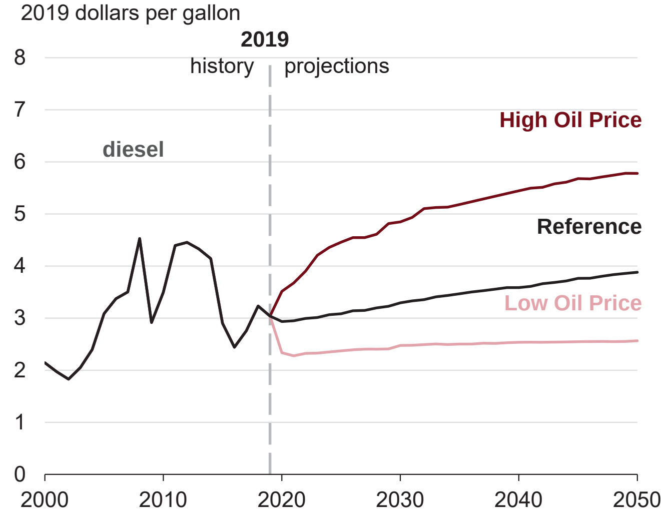
- In the AEO2020, strong production growth and decreasing domestic demand drive the United States to export higher volumes of crude oil and liquid fuels than it imports, resulting in growing levels of net exports from 2020 to 2033.
- In the AEO2020 Reference case, net exports of U.S. petroleum and other liquids peak at more than 3.8 million barrels per day (b/d) in the early 2030s before gradually declining as domestic consumption rises. The United States continues to export more petroleum and other liquids than it imports. Net exports of petroleum and other liquids reach 0.2 million b/d in 2050 as domestic consumption slowly increases but remains 1.2 million b/d below the peak levels recorded in 2004.
- Additional resources and higher levels of technological improvement in the AEO2020 High Oil and Gas Supply case result in more U.S. crude oil production and exports; net exports reach a high of 8.9 million b/d in the mid-2030s. Projected net exports reach a high of 9.6 million b/d in the mid-2020s in the High Oil Price case as a result of higher prices that support more domestic production.
- In the AEO2020 Low Oil Price case, by the mid-2020s, the United States exports 1.1 million b/d more than it imports before rising consumption leads the United States to become a net importer, importing 5.5 million b/d more than it exports in 2050.
- All AEO2020 cases except the Low Oil and Gas Supply and Low Oil Price cases project that the United States will export more petroleum and other liquids than it imports through 2050.

Prices for gasoline and diesel fuel rise throughout the Reference case projection period and primarily follow the price of crude oil in the High Oil Price and Low Oil Price cases

AEO2020 retail prices of motor gasoline
2019 dollars per gallon



AEO2020 retail prices of diesel
2019 dollars per gallon

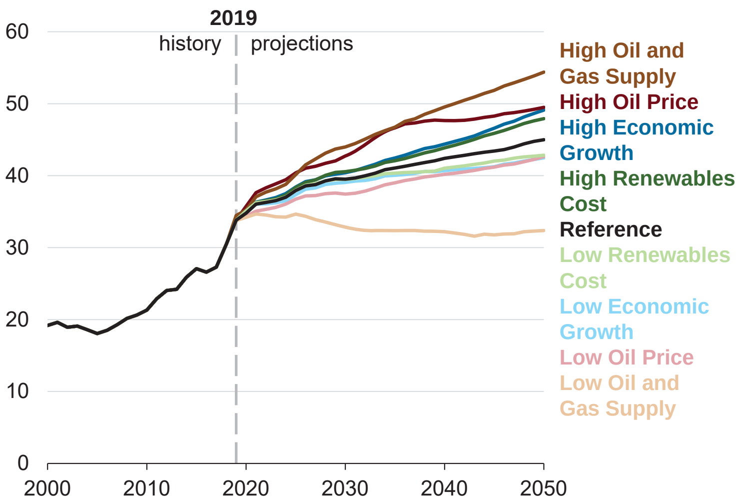


Natural gas

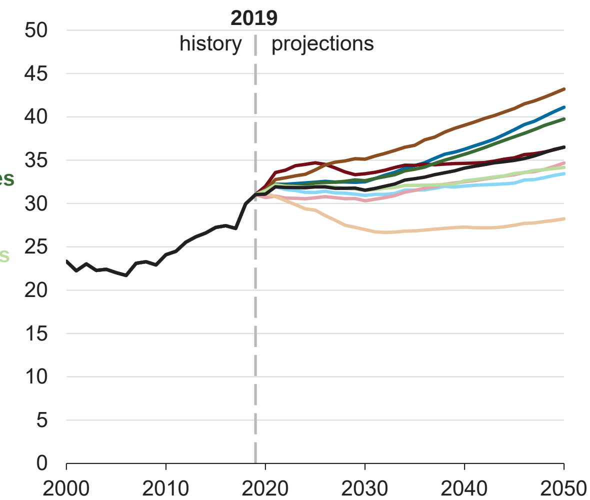
Natural gas production increases in most cases, supporting higher levels of domestic consumption and natural gas exports. However, AEO2020 projections are sensitive to resource and technology assumptions.

U.S. dry natural gas production and consumption increase in most AEO2020 cases—

AEO2020 U.S. dry natural gas production
trillion cubic feet



AEO2020 U.S. natural gas consumption
trillion cubic feet

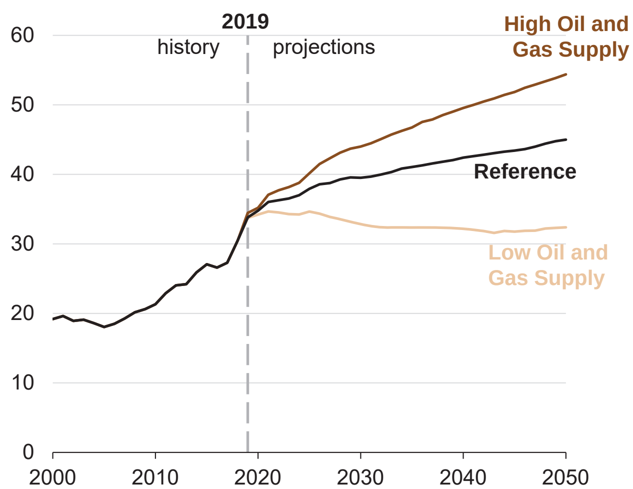


—and natural gas production growth outpaces consumption in most cases

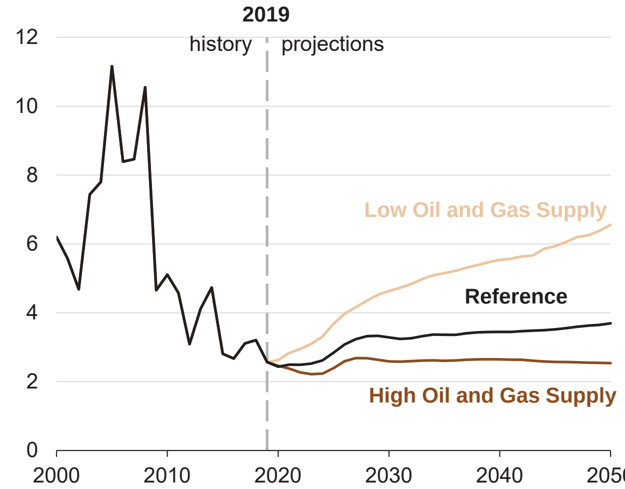
- Natural gas dry production in the AEO2020 Reference case grows 1.9% per year from 2020 to 2025, which is considerably slower than the 5.1%-per-year average growth rate from 2015 to 2020.
- U.S. natural gas consumption in the Reference case slows after 2020 and remains relatively flat through 2030 because of slower industrial sector growth. Consumption also declines in the electric power sector during this period. After 2030, consumption growth rises almost 1% per year on average as natural gas use in the electric power and industrial sectors increases.
- U.S. natural gas production grows at a faster rate than consumption in most cases after 2020, leading to an increase in U.S. exports of natural gas. The exception is in the AEO2020 Low Oil and Gas Supply case, where production and consumption remain relatively flat as a result of higher production costs.

AEO2020 natural gas prices depend on resource and technology assumptions—

AEO2020 dry natural gas production
trillion cubic feet



AEO2020 natural gas spot price at Henry Hub
2019 dollars per million British thermal units



—and Henry Hub prices in the AEO2020 Reference case remain lower than $4 per million British thermal units throughout the projection period

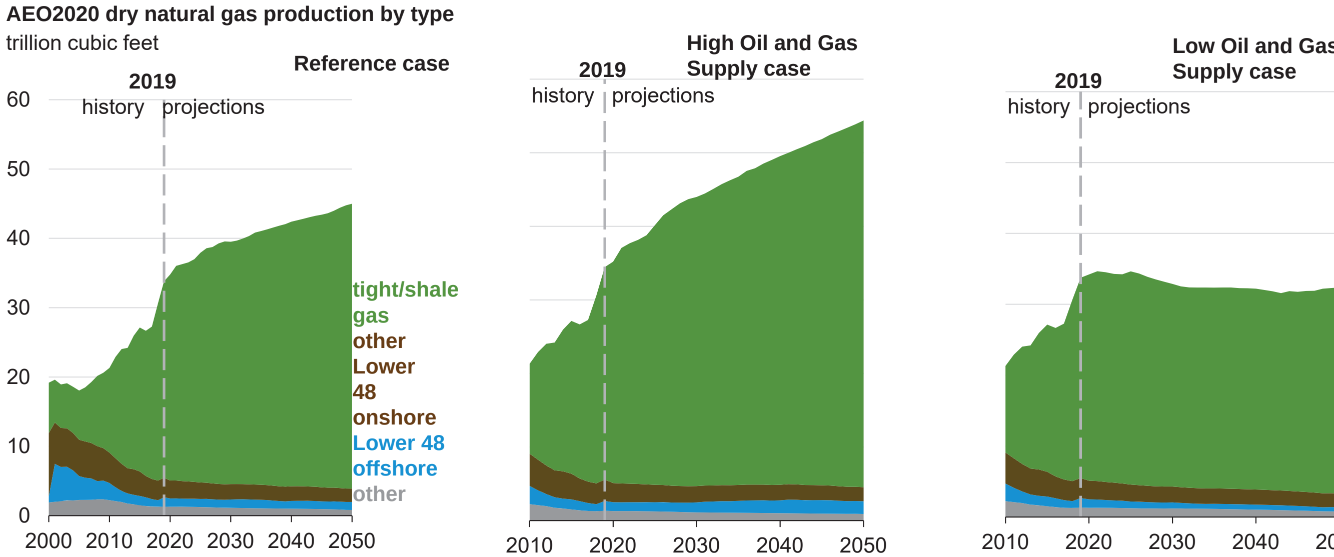
- In the AEO2020 Reference case, growing demand in domestic and export markets leads to increasing natural gas spot prices at the U.S. benchmark Henry Hub through 2050 despite continued technological advances that support increased production.

- To satisfy the growing demand for natural gas, U.S. natural gas production expands into less prolific and more expensive-to-produce areas, putting upward pressure on production costs.

- Natural gas prices in the AEO2020 Reference case remain lower than $4 per million British thermal units (MMBtu) through 2050 because of an abundance of lower cost resources, primarily in tight oil plays in the Permian Basin. These lower cost resources allow higher production levels at lower prices during the projection period.

- The AEO2020 High Oil and Gas Supply case--which reflects lower finding, development, and production costs and greater resource availability--shows an increase in U.S. natural gas production and lower prices relative to the Reference case. In the Low Oil and Gas Supply case, high prices, which result from higher costs and fewer available resources, result in less domestic consumption and exports during the projection period.

U.S. dry natural gas production in AEO2020 increases as a result of continued development of tight and shale resources—



—which account for more than 90% of dry natural gas production in 2050 in the Reference case

- Natural gas production from shale gas and tight oil plays continues to grow, both as a share of total U.S. natural gas production and in absolute volume, in the AEO2020 Reference case. This growth is a result of the size of the associated resources, which extend over nearly 500,000 square miles, and improvements in technology that allow development of these resources at lower costs.

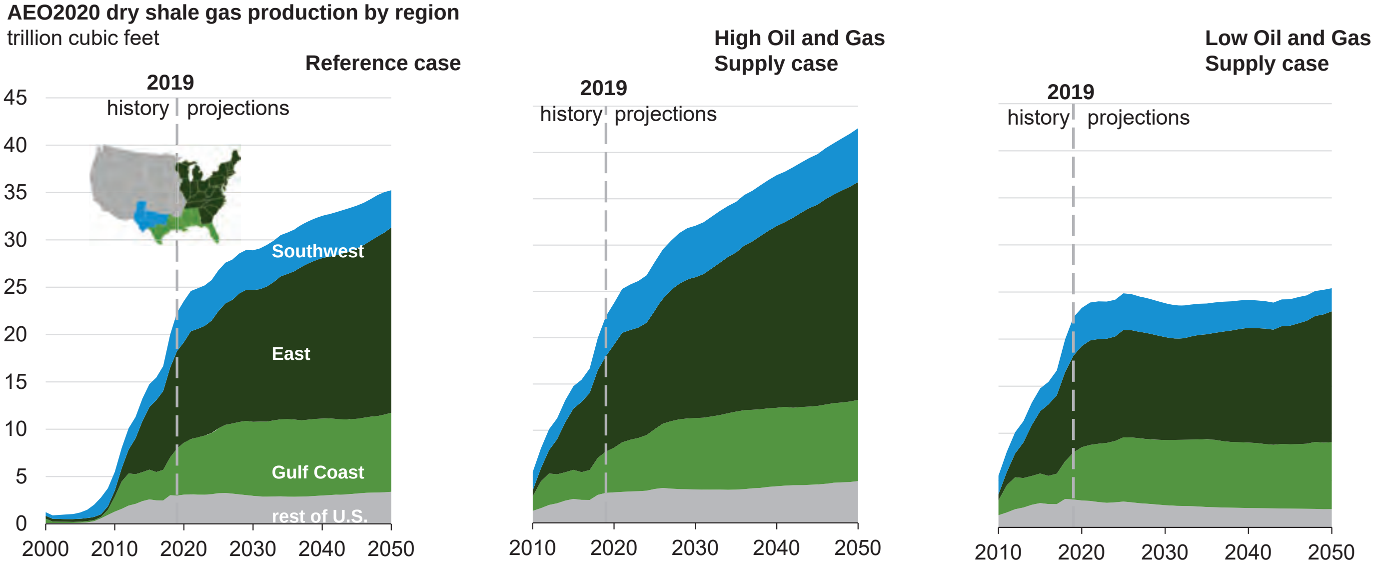
- In the High Oil and Gas Supply case, which has more optimistic assumptions regarding resource size and recovery rates, cumulative production from shale gas and tight oil is 14% higher than in the Reference case. Conversely, in the Low Oil and Gas Supply case, cumulative production from those resources is 20% lower than in the Reference case.

- Across all AEO2020 cases, onshore production of natural gas from sources other than tight oil and shale gas, such as coalbed methane, generally continues to decline through 2050 because of unfavorable economic conditions for producing these resources.

- Offshore natural gas production in the United States remains relatively flat during the projection period in all cases, driven by production from new discoveries that generally offsets declines in legacy fields.

Eastern U.S. production of natural gas from shale resources leads growth in the AEO2020 Reference case—

AEO2020 dry shale gas production by region
trillion cubic feet

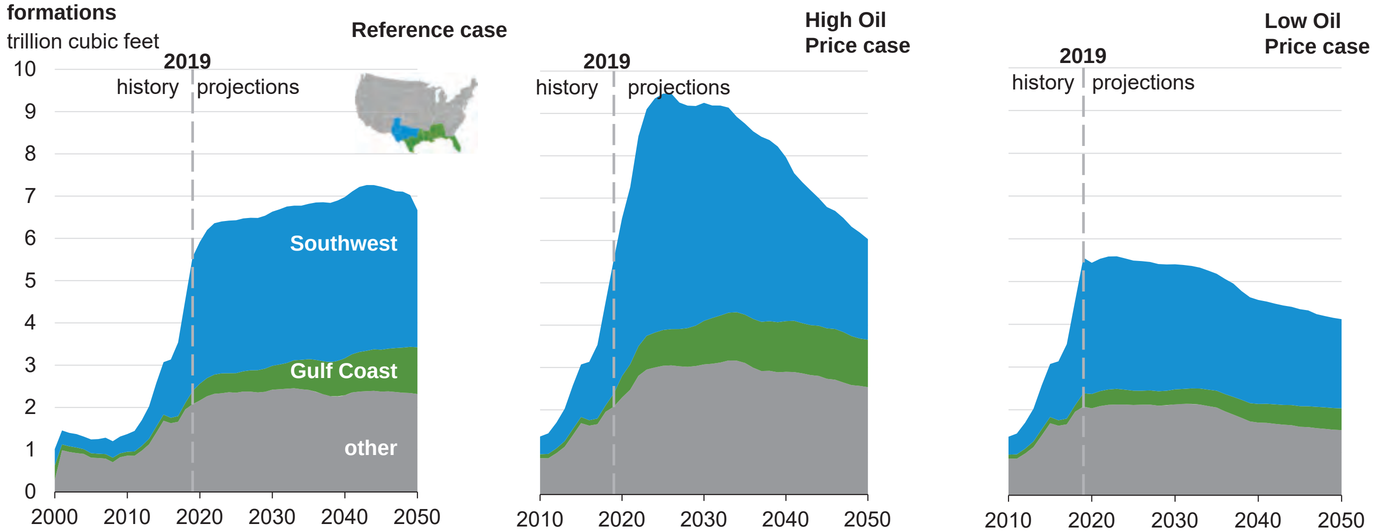


—followed by growth in Gulf Coast onshore production

- Total U.S. natural gas production across most AEO2020 cases is driven by the continued development of the Marcellus and Utica shale plays in the East.
- Natural gas from the Eagle Ford (coproduced with oil) and the Haynesville plays in the Gulf Coast region also materially contributes to domestic dry natural gas production.
- Natural gas production associated with tight oil in the Permian Basin in the Southwest region greatly increases until 2022 but remains relatively flat afterwards to 2050.
- Technological advancements and improvements in industry practices lower production costs in the Reference case and increase the volume of oil and natural gas recovery per well. These advancements have a significant cumulative effect in plays that extend over wide areas and that have large undeveloped resources (for example, Marcellus, Utica, and Haynesville).
- Natural gas production from regions with shale and tight resources shows higher levels of variability across the AEO2020 supply side cases compared with the Reference case because assumptions in those cases target those resources.

The United States continues to produce large volumes of natural gas from oil formations—

AEO2020 dry natural gas production from oil formations

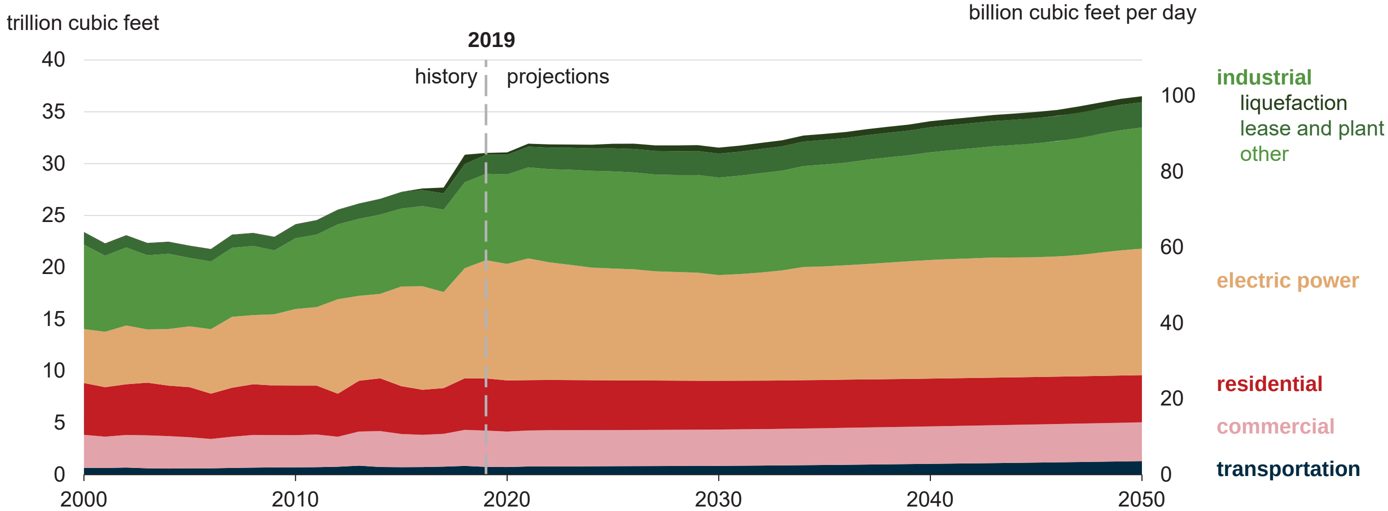


—even though relatively low oil prices put downward pressure on natural gas prices

- The percentage of dry natural gas production from oil formations in the United States increased from 8% in 2013 to 15% in 2018 and remains near this percentage through 2050 in the AEO2020 Reference case.
- Increased drilling in the Southwest, particularly in the Wolfcamp formation in the Permian Basin, is the main driver of growth in natural gas production from tight oil formations.
- The AEO2020 Low Oil Price case (which reflects a U.S. crude oil benchmark West Texas Intermediate price at $56 per barrel or lower) is the only case in which U.S. natural gas production from oil formations is lower in 2050 than current levels.
- The level of drilling in oil formations primarily depends on crude oil prices rather than natural gas prices. Increased natural gas production from oil-directed drilling puts downward pressure on natural gas prices throughout the projection period.

Industrial and electric power demand drives U.S. natural gas consumption growth—

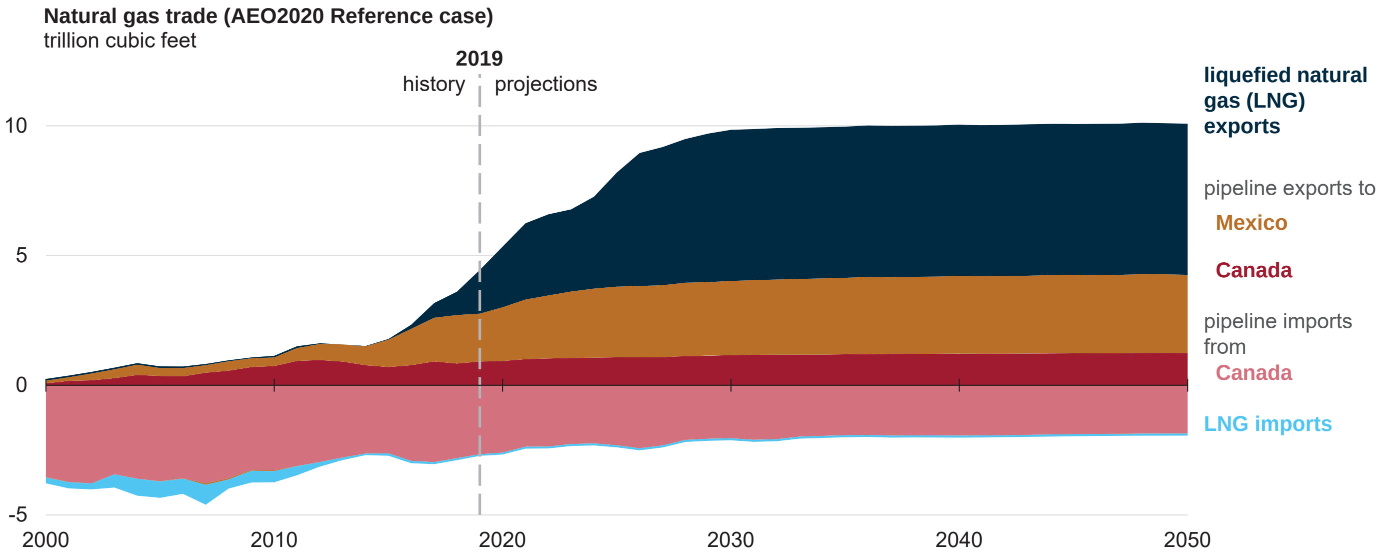
Natural gas consumption by sector (AEO2020 Reference case)



—but consumption in the residential and commercial sectors remains relatively flat across the projection period in the AEO2020 Reference case

- Relatively low U.S. natural gas prices in the AEO2020 Reference case lead to continued growth in natural gas consumption in the near term, particularly in the electric power sector. However, through 2050, only the industrial sector shows markedly increased natural gas consumption.
- The industrial sector, which includes fuel used for liquefaction at export facilities and in lease and plant operations, consumes more natural gas than any other sector in the United States after 2021. Major natural gas consumers in this sector include the chemical industry (where natural gas is used as a feedstock to produce methanol and ammonia), manufacturing heat and power, and lease and plant fuel.
- Natural gas used for U.S. electric power generation peaks in 2021 as relatively low natural gas prices, new natural gas-fired combined-cycle capacity, and coal-fired capacity retirements drive increases in natural gas-fired generation in the short term. However, strong growth in renewables and efficiency improvements in the remaining coal-fired fleet lead to declining amounts of natural gas consumed in the electric power sector through 2030. Natural gas consumption then slowly rises to reach its 2021 level again in the late 2040s.
- Natural gas consumption in the residential and commercial sectors remains largely flat because of efficiency gains and population shifts to warmer regions that counterbalance population growth. Although natural gas consumption rises in the transportation sector--particularly for freight trucks, rail, and marine shipping--it remains a small share of both transportation fuel demand and total natural gas consumption.

The United States continues to export more natural gas than it imports in the AEO2020 Reference case—

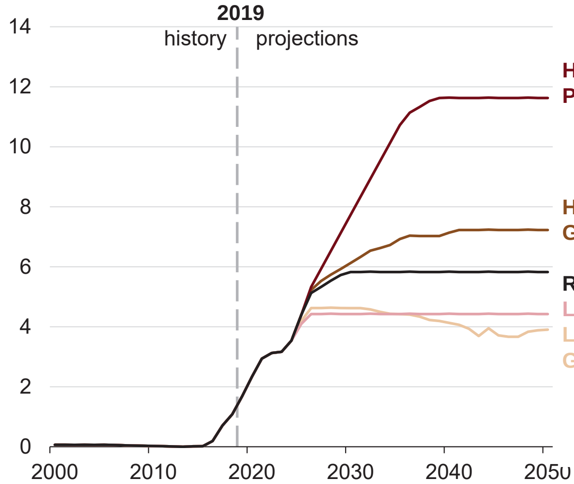


—because near-term growth in liquefied natural gas export capacity delivers domestic production to global markets

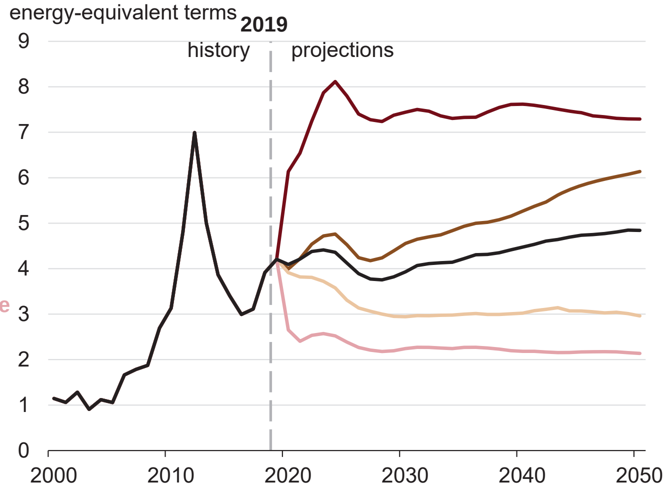
- In the AEO2020 Reference case, pipeline exports to Mexico and liquefied natural gas (LNG) exports to world markets increase moderately until 2025, after which pipeline export growth to Mexico slows. LNG exports continue to rise through 2030 before remaining relatively flat for the remainder of the projection period.
- Increasing natural gas exports to Mexico are a result of more pipeline infrastructure to and within Mexico, allowing for increased natural gas-fired power generation. By 2030, Mexico's domestic natural gas production begins to displace U.S. exports.
- Three more LNG-export facilities became operational in the Lower 48 states in 2019, bringing the total number to six. Two new LNG projects reached final investment decisions and started construction in 2019. All LNG-export facilities and expansions currently under construction are expected to be completed by 2025. U.S. LNG-export capacity will continue to serve growing global LNG demand, particularly in emerging Asian markets as long as U.S. natural gas prices remain competitive. As U.S.-sourced LNG becomes less competitive in world markets after 2030, export volumes level off.
- U.S. imports of natural gas from Canada, primarily from its prolific western region, continue to generally decline from historical levels. U.S. exports of natural gas to eastern Canada continue to increase because of eastern Canada's proximity to U.S. natural gas resources in the Marcellus and Utica plays and new pipeline infrastructure. However, this export growth slows in the mid-2020s as Canada's demand for natural gas begins to decline, particularly in the electric power sector, as Canada begins transitioning to more renewables in its generation mix.

Liquefied natural gas (LNG) exports are sensitive to both oil and natural gas prices—

AEO2020 liquefied natural gas exports
trillion cubic feet



Ratio of Brent crude oil price to natural gas price at Henry Hub in AEO2020
energy-equivalent terms



—resulting in a wide range of U.S. LNG-export levels across cases

- Historically, most LNG was traded under long-term contracts linked to crude oil prices because the regional nature of natural gas markets prevented the development of a natural gas price index that could be used globally. In addition to providing a liquid global pricing benchmark, crude oil, to some degree, can act as a substitute for natural gas in industry and for power generation.

- As more natural gas is traded via short-term contracts or traded on the spot market, the link between LNG and oil prices weakens over time, making U.S. LNG exports less sensitive to the crude oil-to-natural gas price ratio and more responsive to the global LNG supply-natural gas demand dynamics. This shift causes growth in U.S. LNG exports to slow in all cases.

- When the crude oil-to-natural gas price ratio is highest, such as in the High Oil Price case, U.S. LNG exports are at their highest levels. U.S. LNG supplies are priced based on relatively low domestic spot prices instead of oil-linked contracts. In addition, demand for LNG increases, in part, as a result of consumers moving away from petroleum products.

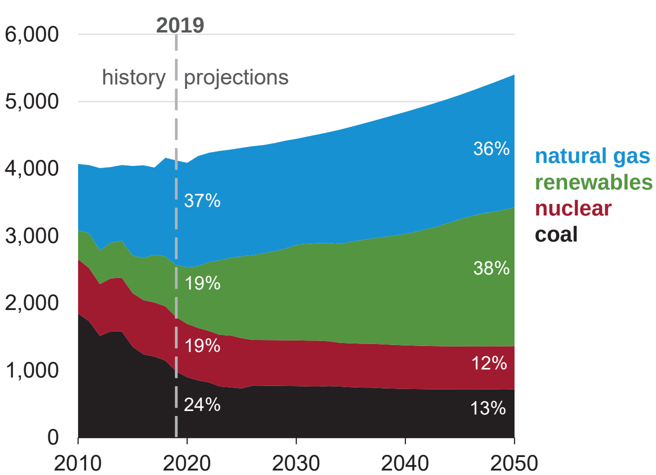
- In the High Oil and Gas Supply case, low U.S. natural gas prices make U.S. LNG exports competitive relative to other suppliers. Conversely, higher U.S. natural gas prices in the Low Oil and Gas Supply case result in lower U.S. LNG exports.

Electricity

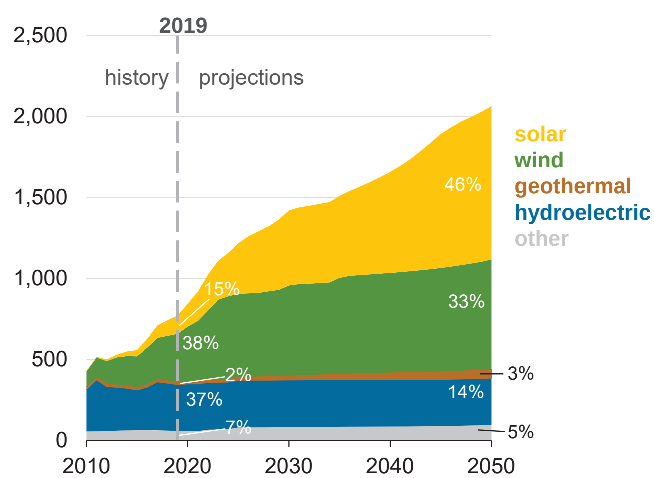
As electricity demand grows modestly, the primary drivers for new capacity in the AEO2020 Reference case are retirements of older, less-efficient fossil fuel units; the near-term availability of renewable energy tax credits; and the continued decline in the capital cost of renewables, especially solar photovoltaic. Low natural gas prices and favorable costs for renewables result in natural gas and renewables as the primary sources of new generation capacity through 2050. The future generation mix is sensitive to the price of natural gas and growth in electricity demand.

Electricity generation from natural gas and renewables increases as a result of lower natural gas prices and declining costs of solar and wind renewable capacity, making these fuels increasingly competitive

Electricity generation from selected fuels (AEO2020 Reference case)
billion kilowatthours

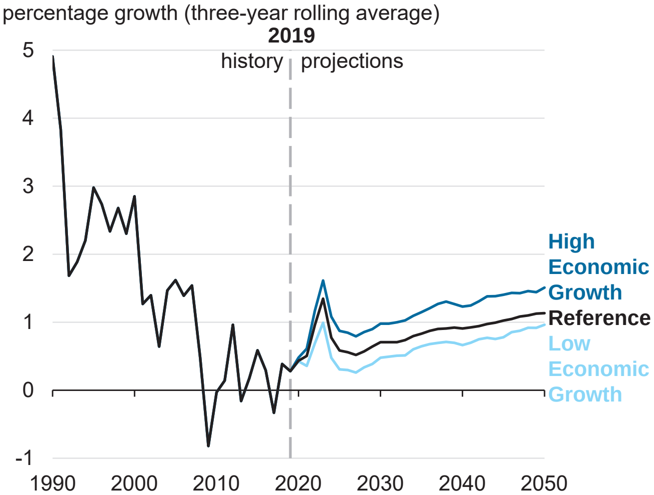


Renewable electricity generation, including end use (AEO2020 Reference case)
billion kilowatthours

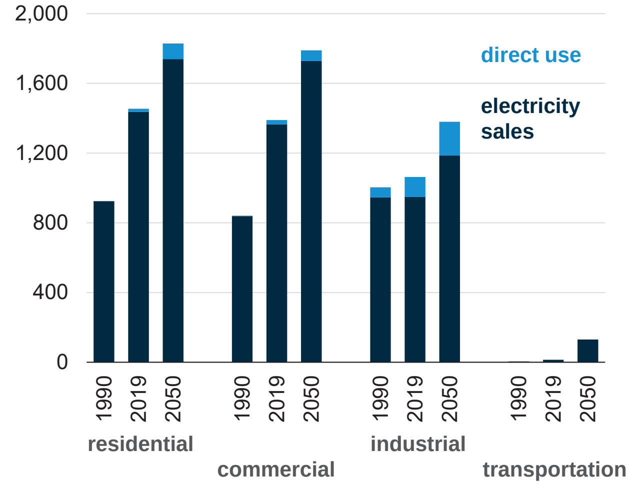


Electricity demand grows slowly through 2050 in the AEO2020 Reference case—

AEO2020 Electricity use growth rate
percentage growth (three-year rolling average)



Electricity use by end-use sector (AEO2020 Reference case)
billion kilowatthours

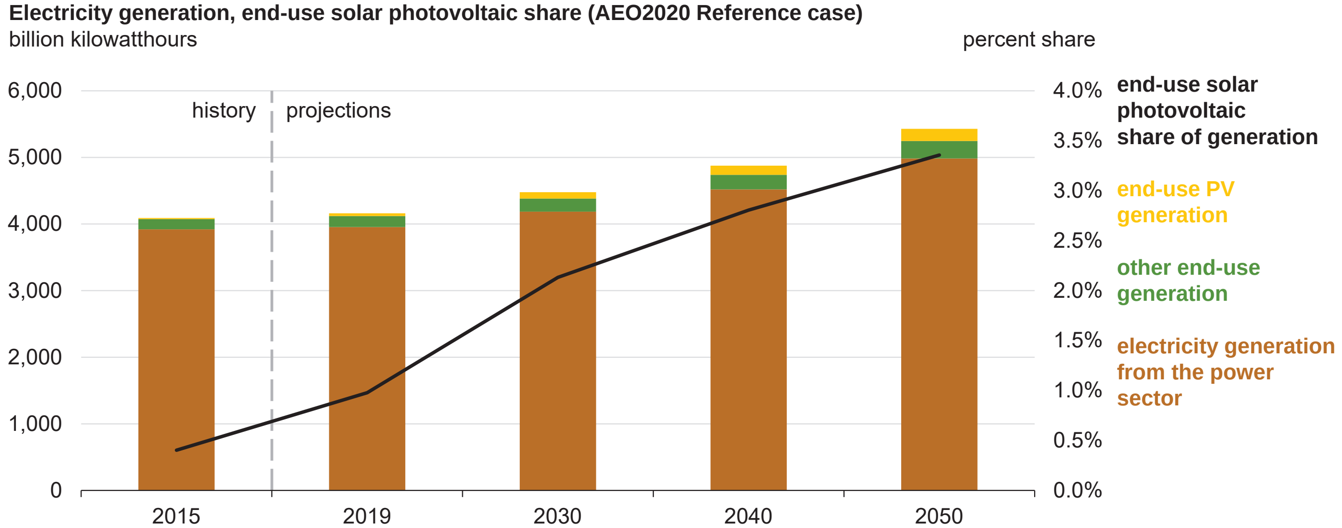


—with increases occurring across all end-use sectors

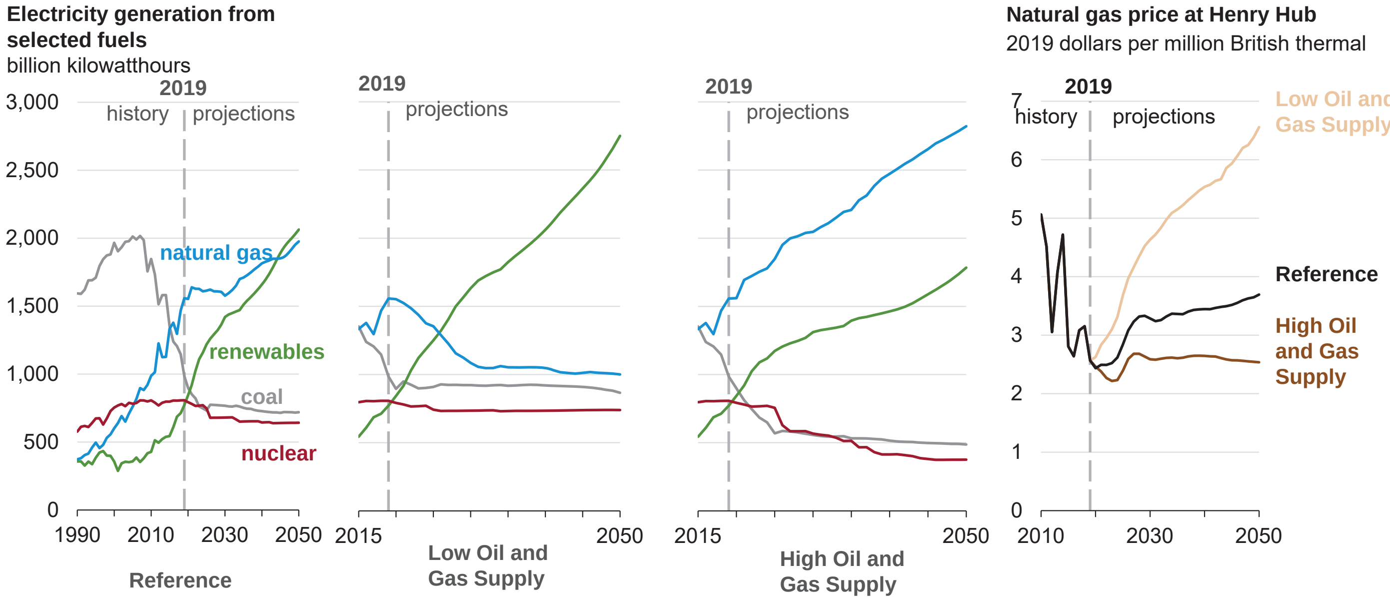
- Although near-term electricity demand may fluctuate as a result of year-to-year changes in weather, trends in long-term demand tend to be driven by economic growth offset by increases in energy efficiency. The annual growth in electricity demand averages about 1% throughout the projection period (2019-2050) in the AEO2020 Reference case.
- Historically, although the economy has continued to grow, growth rates for electricity demand have slowed as new, efficient devices and production processes that require less electricity have replaced older, less-efficient appliances, heating, ventilation, cooling units, and capital equipment.
- Average electricity growth rates in the AEO2020 High Economic Growth and Low Economic Growth cases vary the most from the Reference case. Electricity use in the High Economic Growth case grows 0.3 percentage points faster on average, and electricity use in the Low Economic Growth case grows 0.2 percentage points slower.
- The growth in projected electricity sales during the projection period would be higher if not for significant growth in generation from rooftop photovoltaic (PV) systems, primarily on residential and commercial buildings, and combined-heat-and-power systems in industrial and some commercial applications. By 2050, end-use solar photovoltaic accounts for 4% of U.S. generation in the AEO2020 Reference case.
- Electric power demand from the transportation sector is a very small percentage of economy-wide demand because electric vehicles (EVs) still represent a developing market. Given the lack of market evidence to date that would indicate a significant increase in U.S. consumer preference for EVs, EIA's AEO2020 projections reflect the dependence of the EV market on regulatory policies. Both vehicle sales and utilization (miles driven) would need to increase substantially for EVs to raise electric power demand growth rates by more than a fraction of a percentage per year.

An increasing share of total electricity demand is met with customer-owned generation, including rooftop solar photovoltaic

Electricity generation, end-use solar photovoltaic share (AEO2020 Reference case)



Declining costs for new wind and solar projects support the growing renewables share of the generation mix across a wide range of assumptions—



—although the results are sensitive to natural gas resource and price assumptions

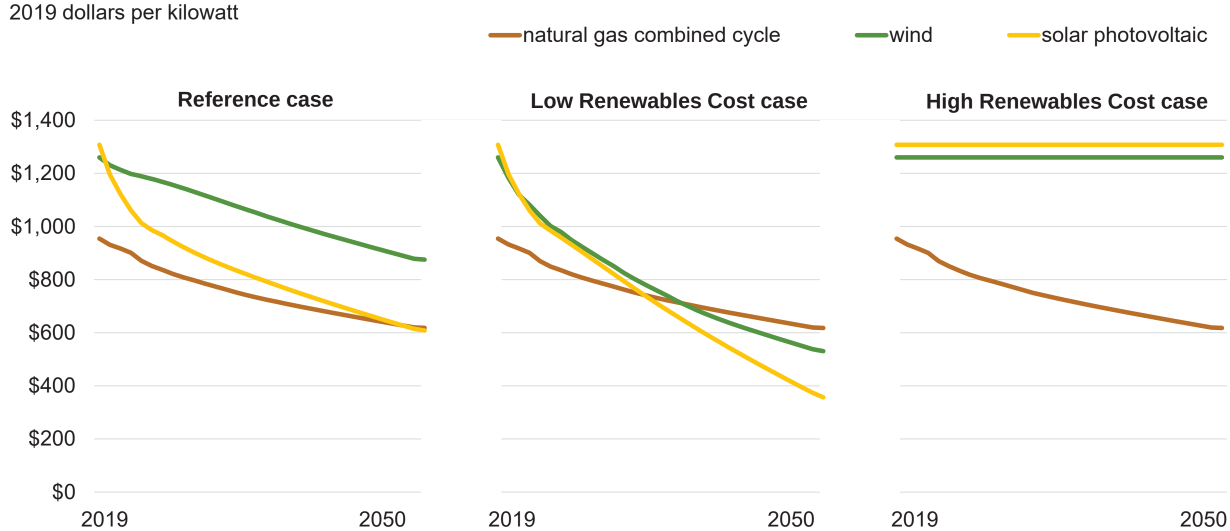
- Because of declining capital costs and higher renewable portfolio standards (RPS) targets in some states, AEO2020 projects that the relatively sharp growth in renewables seen during the past 10 years will continue through the projection period. Total renewable generation exceeds natural gas-fired generation after 2045 in the AEO2020 Reference case. Renewable generation grows faster than overall electricity demand.

- Although coal-fired and nuclear generation decline through the mid-2020's as a result of retirements, generation from these sources stabilizes over the longer term as the more economically viable plants remain in service. At projected Reference case prices, natural gas-fired generation is the marginal fuel source to fulfill incremental demand and increases in the later projection years, averaging 0.8% growth per year through 2050.

- As a result of projected lower natural gas prices in the High Oil and Gas Supply case, natural gas-fired generation increases 1.9% per year through the projection period, reaching a 51% share of the generation mix by 2050. In contrast, under the projected higher natural gas prices in the Low Oil and Gas Supply case, natural gas-fired generation declines 1.4% per year through 2050, reaching a 19% share of the generation mix by 2050.

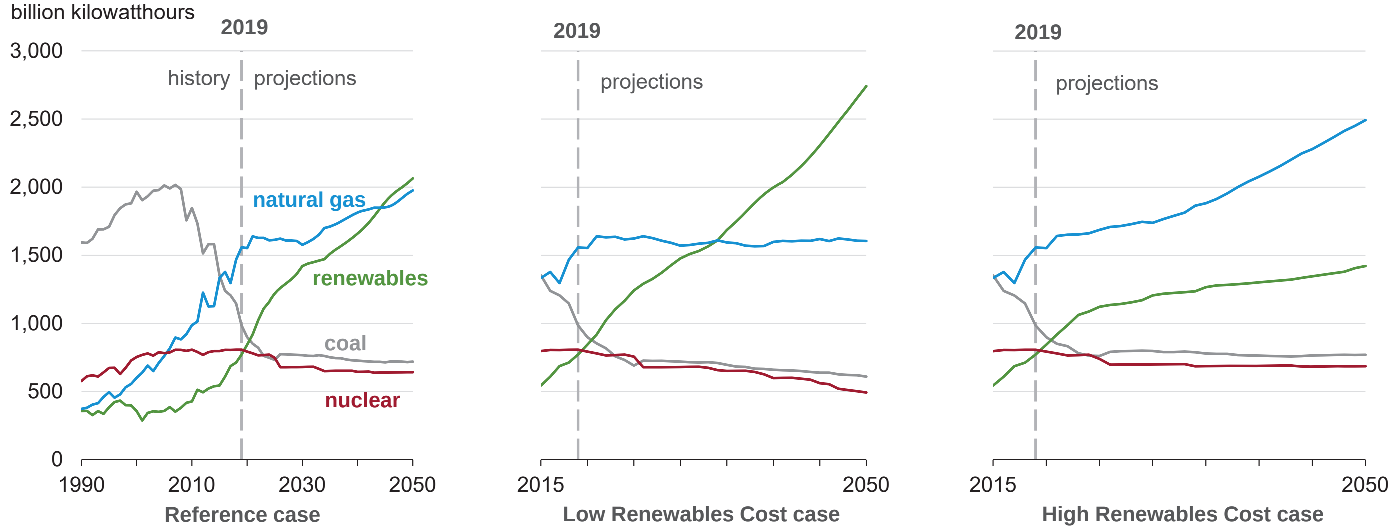
The High Renewables Cost and Low Renewables Cost cases assume different rates of cost reduction for renewable technologies compared with the Reference case; non-renewables assume the same rates

AEO2020 overnight installed cost by technology
2019 dollars per kilowatt



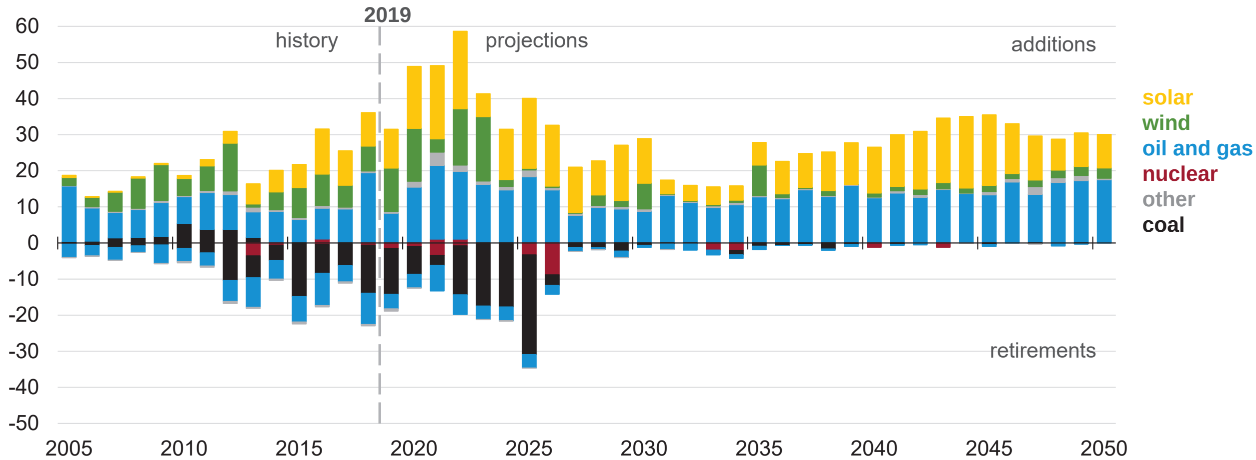
Changes in cost assumptions for new wind and solar projects result in significantly different projected fuel mixes for electricity generation

AEO2020 electricity generation from selected fuels
billion kilowatthours



Expected requirements for new generating capacity will be met by renewables and natural gas in the AEO2020 Reference case—

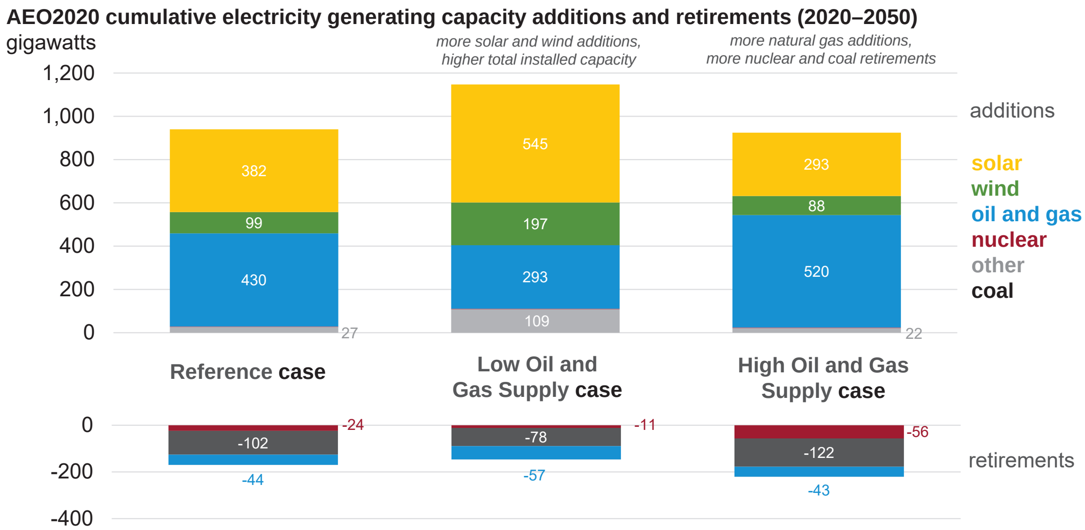
Annual electricity generating capacity additions and retirements (Reference case)
gigawatts



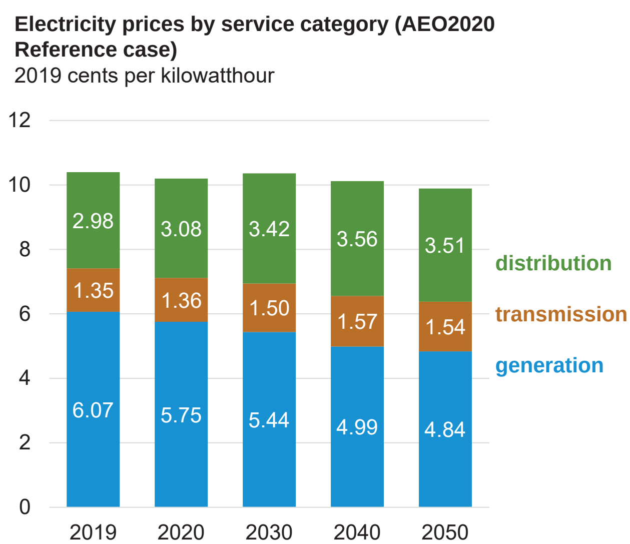
—as a result of competitive natural gas prices and declining costs for renewables

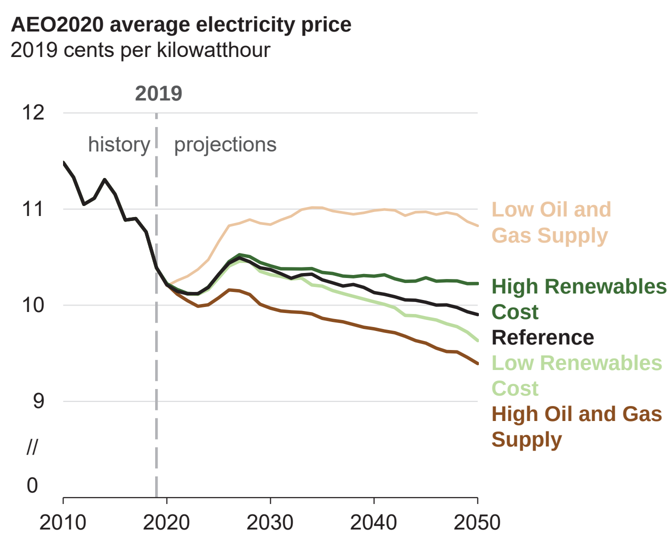
- In the AEO2020 Reference case, the United States adds 117 gigawatts (GW) of new wind and solar capacity between 2020 and 2023, which is the result of tax credits, increasing RPS targets, and declining capital costs.
- New wind capacity additions continue at much lower levels after production tax credits expire in the early 2020s, but the growth in solar capacity continues through 2050 for both the utility-scale and small-scale applications because the cost of solar PV declines throughout the projection period.
- Natural gas-fired combined-cycle generation capacity is also added steadily throughout the projection period to meet rising demand.
- Most of the electric generation capacity retirements assumed in the AEO2020 Reference case occur by 2025. Although the final schedule will depend upon state-level implementation plans, in AEO2020 EIA assumes that coal-fired plants must either invest in heat rate improvement technologies by 2025 or retire to comply with the Affordable Clean Energy (ACE) rule. Heat rate improvement technologies increase the efficiency of power plants. The remaining coal plants are more efficient and continue to operate throughout the projection period. Low natural gas prices in the early years also contribute to the retirements of coal-fired and nuclear plants because both coal and nuclear generators are less profitable in these years.

AEO2020's long-term trends in electricity generation are dominated by solar and natural gas-fired capacity additions; coal, nuclear, and less efficient natural gas generators contribute to capacity retirements



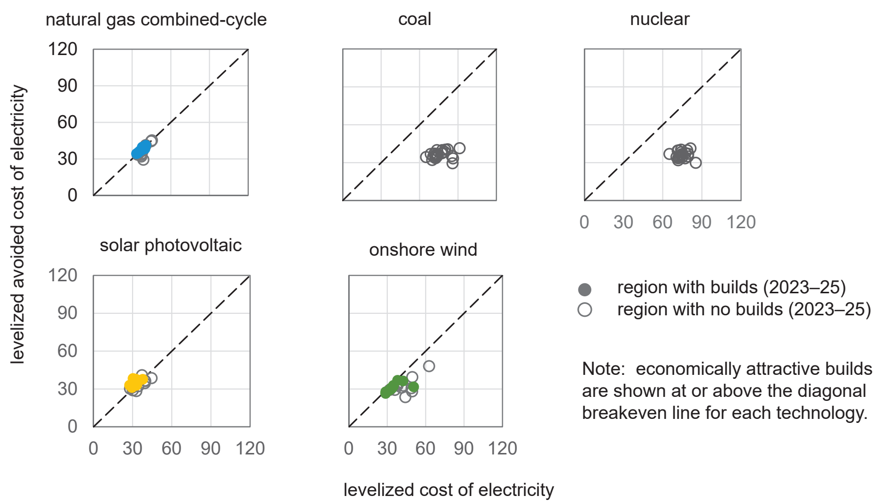
AEO2020 Reference case electricity prices fall slightly; declining generation costs are offset by rising transmission and distribution costs





In the AEO2020 Reference case, combined-cycle and solar photovoltaic are the most economically competitive generating technologies—

AEO2020 levelized cost of electricity and levelized avoided cost of electricity by technology and region, 2025
2019 dollars per megawatthour

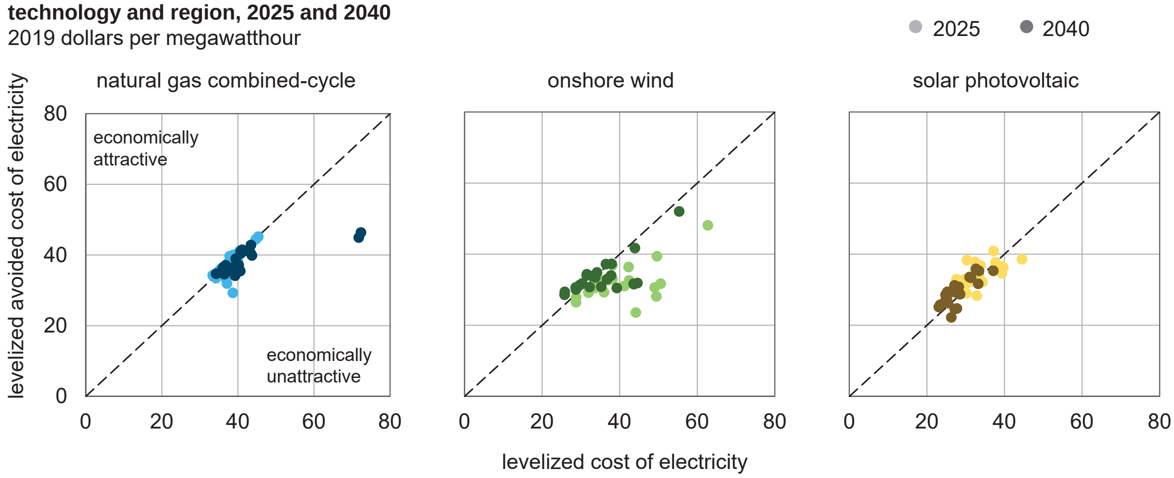


—when considering the overall cost to build and operate and the value of the plant to the grid

- The levelized cost of electricity (LCOE) reflects the cost to build and operate a power plant per unit of generation, annualized over a cost recovery period. When compared with the levelized avoided cost of electricity (LACE), or expected average revenue realized by that plant, we can estimate the economic competitiveness for that generating technology.
- The solid, colored circles on the figure indicate that projects tend to be built in regions where revenue (LACE) exceeds costs (LCOE). In the AEO2020 Reference case, expected revenues from electric generation for both natural gas-fired combined-cycle and solar photovoltaic with single axis tracking are generally greater than or equal to projected costs across the most electricity market regions in 2025. Correspondingly, these two technologies show the greatest projected growth through the middle of the 2030s.
- The value of wind approaches its cost in nearly half of the regions. These regions see new wind capacity builds in the AEO2020 Reference case, primarily in advance of the phase-out of the production tax credit (PTC), through the early part of the next decade.
- LACE accounts for both the variation in daily and seasonal electricity demand in the region where a new project is under consideration and the characteristics of the existing generation fleet where the new capacity will be added. The prospective new generation resource is compared with the mix of new and existing generation and capacity that it would displace. For example, a wind resource that would primarily displace existing natural gas-fired generation will usually have a different value than one that would displace existing coal-fired generation.

Onshore wind will become more competitive over time, while natural gas-fired combined-cycle and solar photovoltaic maintain their current competitive positions—

AEO2020 Reference case levelized cost of electricity (LCOE) and levelized avoided cost of electricity (LACE) by technology and region, 2025 and 2040
2019 dollars per megawatthour



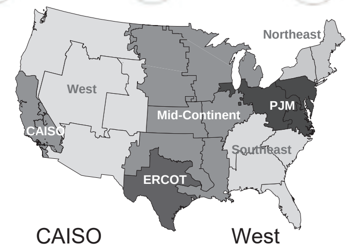
—as LCOE declines through learning-induced cost reductions and LACE increases with rising demand and natural gas prices

- Changes in AEO2020 electricity generation costs over time reflect a number of factors, sometimes working in different directions. For both solar photovoltaic (PV) and onshore wind, LCOE increases in the near term with the phase-out and expiration of the investment tax credit (ITC) and PTC, respectively. However, LCOE eventually declines over time because technological improvements tend to reduce LCOE through lower capital cost or improved performance (as measured by heat rate for natural gas combined-cycle plants or capacity factor for onshore wind or solar PV plants), partly offsetting the loss of the tax credits.

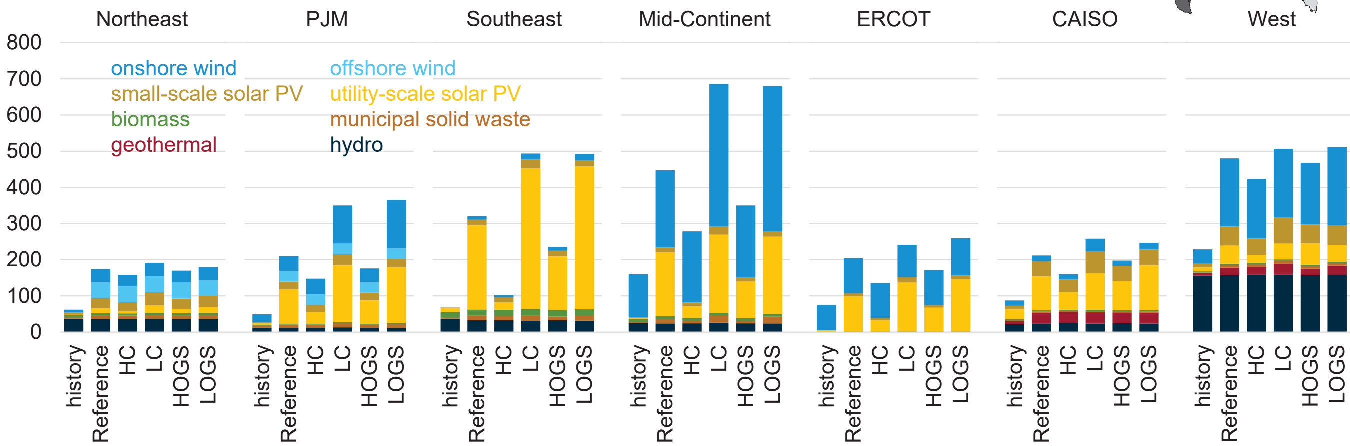
- Natural gas-fired combined-cycle plants with online years of 2025 and 2040 in the AEO2020 projection have similar LCOE because the technology has reached market maturity, judging from the build patterns throughout the projection years across all regions. The two outliers in the 2040 LCOE projection are attributed to the increase in variable operations and in maintenance costs for plants in California as a result of the state's phase-out of fossil fuel-fired generation starting in 2030.

- Solar may show strong daily generation patterns within any given region; therefore, AEO2020 LACE for solar PV declines over time as the market becomes saturated with generation from resources with similar hourly generation patterns. LACE for onshore wind is generally lower than other technologies because most of the generation at these plants occurs at night or during fall and spring seasons when the demand for and the value of electricity is typically lower. Solar PV plants produce most of their energy during the middle of the day when higher demand increases the value of electricity, resulting in higher LACE.

Solar and wind lead the growth in renewables generation in most regions across all cases in AEO2020



Total renewables generation (all sectors), 2018 and 2050
billion kilowatthours



Note: HC = High Renewables Cost, LC = Low Renewables Cost, HOGS = High Oil and Gas Supply, LOGS = Low Oil and Gas Supply, PV= photovoltaic

—but its penetration rate differs by regional resource and generation mix

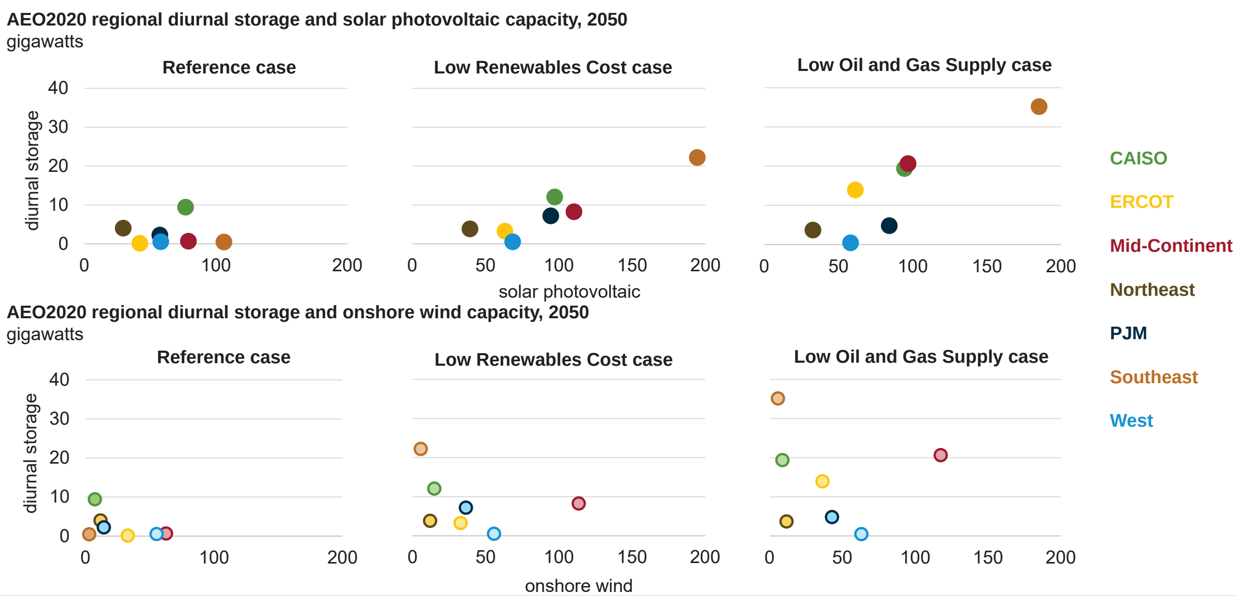
- The AEO2020 projects that generation from renewable sources will rise from 18% of total generation in 2018 to 38% by 2050 in the Reference case. Solar photovoltaic (PV) contributes the most to the growth in renewable generation, increasing from 13% of total renewable generation in 2018 to 46% by 2050. Although onshore wind generation more than doubles during the projection period, its share of renewable generation declines slightly from 37% to 29% between 2018 and 2050.

- Solar PV generation grows the most in Southeast and Mid-Continent regions in nearly all cases. On average, these two regions have higher-than-average delivered U.S. natural gas prices, making natural gas generation a more expensive option to replace retired coal or nuclear generation. Because solar PV generates mostly during daytime hours, it can readily substitute natural gas generation during periods of higher demand. Regions with existing wind capacity continue to install new wind capacity between 2018 and 2050.

- When natural gas prices are higher, as in the Low Oil and Gas Supply case, onshore wind becomes the incremental generation source in the Mid-Continent region, where wind resources are abundant. Wind generation for the region is 189 billion kilowatthours (BkWh) higher (89% increase) in 2050 than in the Reference case, and all-sector solar PV generation is 37 BkWh higher (20% increase).

- The Northeast, ERCOT (Electric Reliability Council of Texas), CAISO (California Independent System Operator), and West regions have relatively small variations in results across the alternative cases. The small variations are most likely a result of the regions' current small shares of existing coal generation capacity that may need to be replaced over the projection period. The share of renewables is also comparatively large in these regions.

Growth in utility-scale battery storage in AEO2020 follows growth in solar in most regions in high renewable penetration scenarios—



- The AEO2020 Reference case projects that the United States will have 17 GW of battery storage capacity in 2050. Storage capacity takes advantage of times when an oversupply of electricity occurs, which generally happens in areas that have a high penetration of non-dispatchable renewable resources such as wind and solar. Limitations in the time a battery can store electricity make batteries more suitable for solar, which has more predictable generation patterns than wind.

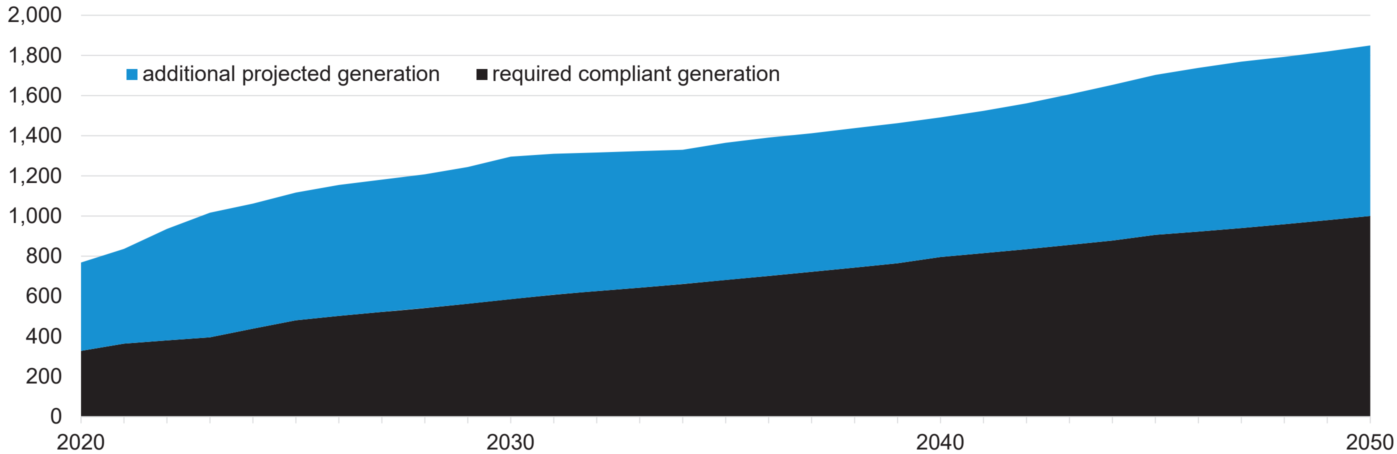
- The large number of combustion turbine (CT) additions in the West and Mid-Continent regions correspond the large number of wind additions in these regions. Because wind energy is less predictable and fluctuates in intensity for long periods, current limitations in the length of time a battery can store or generate power make batteries an inadequate backup for wind power. Therefore, CTs, which have no duration limit as long as natural gas fuel is available, fill the gap. CTs in the West region are also supported by its large hydropower resources.

- Storage growth is stronger in AEO2020 scenarios that have a high penetration of renewables, such as the Low Renewables Cost and Low Oil and Gas Supply cases. The Low Renewables Cost case projects 57 GW of storage by 2050, and the Low Oil and Gas Supply case projects 98 GW of storage by 2050.

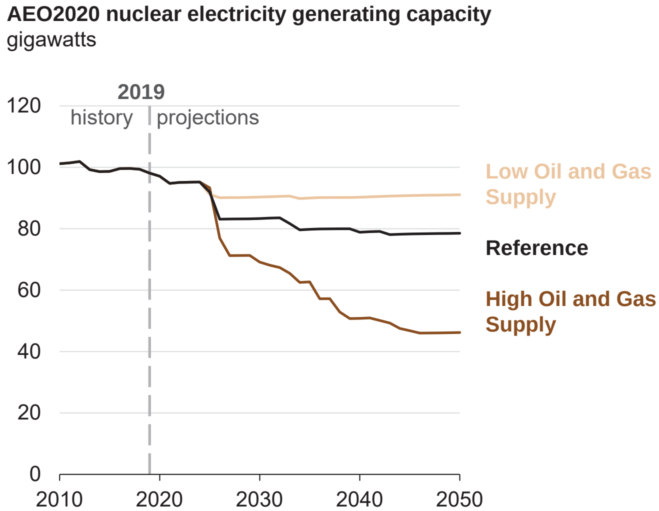
- In both the Low Renewables Cost and Low Oil and Gas Supply cases, the Southeast and California regions see high amounts of solar capacity in 2050, minimal amounts of wind capacity, and concurrently large amounts of battery storage. The Northeast, the West, and the PJM regions have relatively low solar capacity and lower storage capacity.

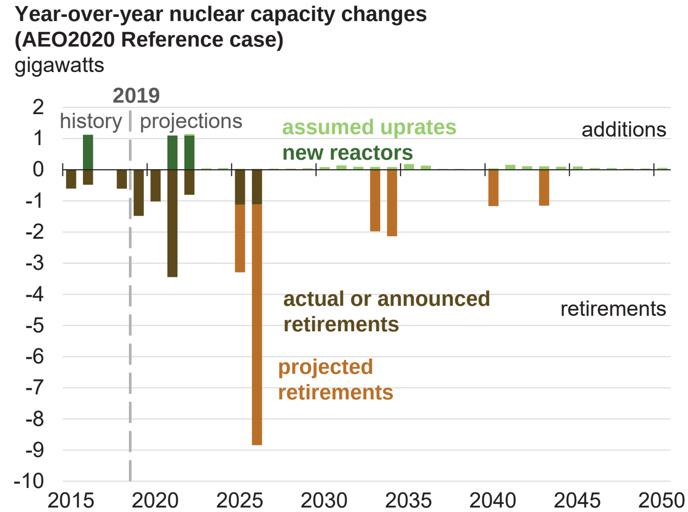
Even with recent increases in several states' renewable portfolio standards, renewable generation that exceeds requirements allows for full compliance in the AEO2020 Reference case by 2050

AEO2020 Reference case total qualifying renewables generation required for combined state renewable portfolio standards and projected total generation from compliant technologies, 2020–2050
billion kilowatthours



Lower natural gas prices throughout the AEO2020 projection period accelerate nuclear capacity retirements—

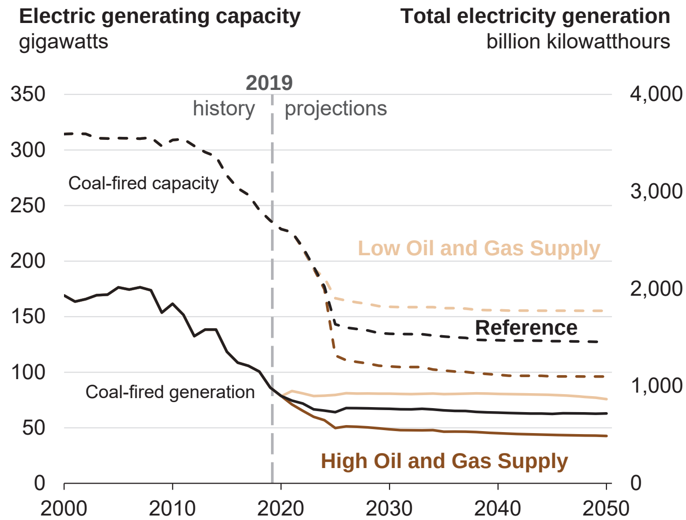


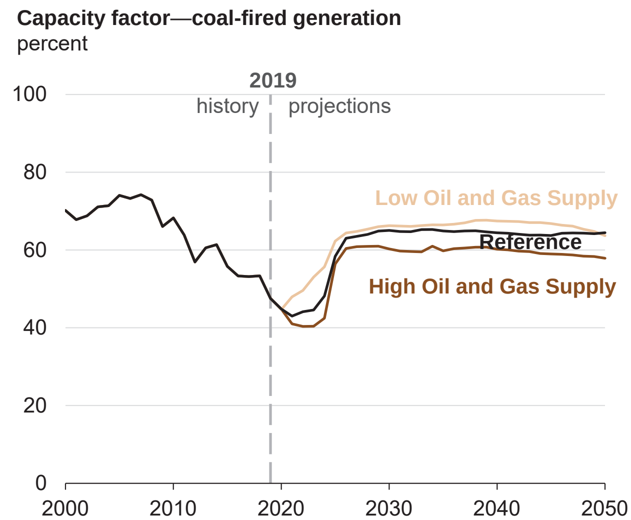


—as a result of declining revenue in competitive wholesale power markets

- The AEO2020 Reference case projects a 19% decline in nuclear electric generating capacity from 98 GW in 2019 to 79 GW in 2050. No new plant additions occur beyond 2022, and existing plants have 2 GW of uprates starting in 2022.
- Projected nuclear retirements are driven by declining revenues that result from low growth in electricity load and from increasing competition from low-cost natural gas and declining-cost renewables. Smaller, single-reactor nuclear plants with higher average operating costs are most affected, particularly those plants operating in regions with deregulated wholesale power markets and in states without a zero emission credit policy.
- Lower natural gas prices in the High Oil and Gas Supply case lead to lower wholesale power market revenues for nuclear power plant operators, accelerating an additional 32 GW of nuclear capacity retirements by 2050 compared with the Reference case.
- Higher natural gas prices in the Low Oil and Gas Supply case help increase profitability for nuclear power plant operators, resulting in 13 GW fewer retirements through 2050 compared with the Reference case.

Coal-fired generating capacity retires at a faster pace than total generation in the AEO2020 Reference case—



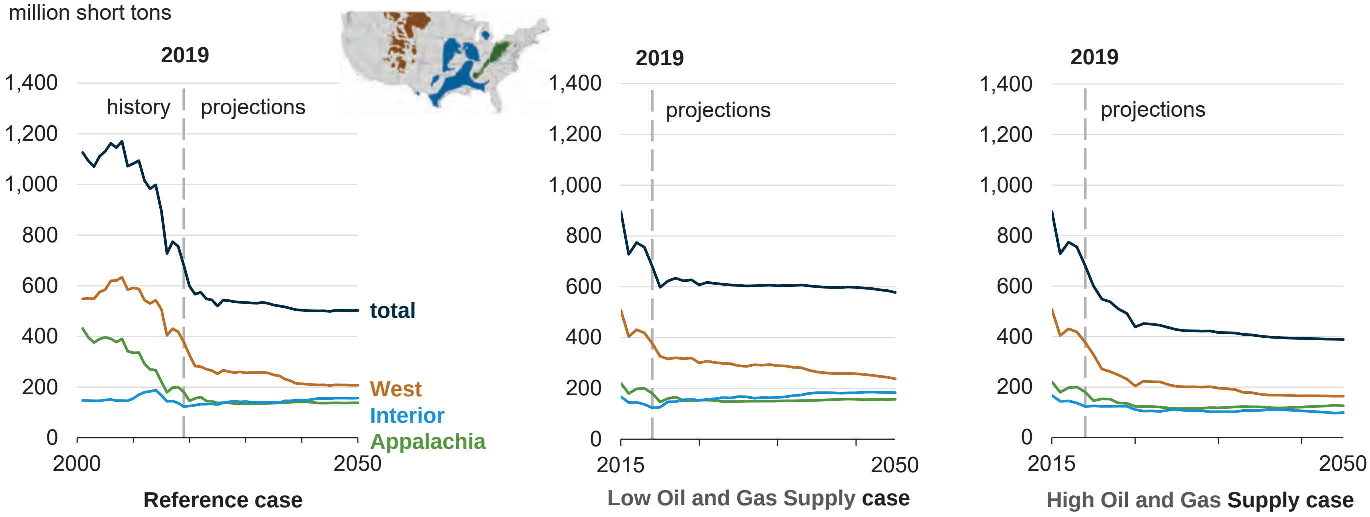


—as capacity factors increase for the more efficient coal-fired units that remain in service

- In addition to decreases as a result of competitively priced natural gas and increasing renewables generation, coal-fired generating capacity decreases by 109 GW (or 46%) between 2019 and 2025 to comply with the Affordable Clean Energy (ACE) rule before leveling off near 127 GW in the AEO2020 Reference case by 2050.
- Average capacity factors for coal-fired generating units improve over time as less-efficient units are retired, as heat rates in the remaining coal fleet improve to comply with the ACE rule, and as natural gas prices increase
- Between 2019 and 2025, coal-fired generation decreases by 26% in the Reference case while natural gas prices increase. By 2030, the utilization rate of the remaining coal-fired capacity returns to 65%, which is slightly less than in the early 2000s. In the High Oil and Gas Supply case, coal-fired generation decreases by 42% between 2019 and 2025, and lower natural gas prices limit the utilization rate of the coal fleet to about 60% in 2030.
- Higher natural gas prices in the Low Oil and Gas Supply case slow the pace of coal power plant retirements by about 23 GW through 2025 compared with the Reference case. The Low Oil and Gas Supply case has 155 GW of coal-fired capacity still in service in 2050. Conversely, lower natural gas prices in the High Oil and Gas Supply case increase coal-fired power plant retirements by 28 GW in 2025, and 96 GW of remaining coal-fired capacity remains by 2050.

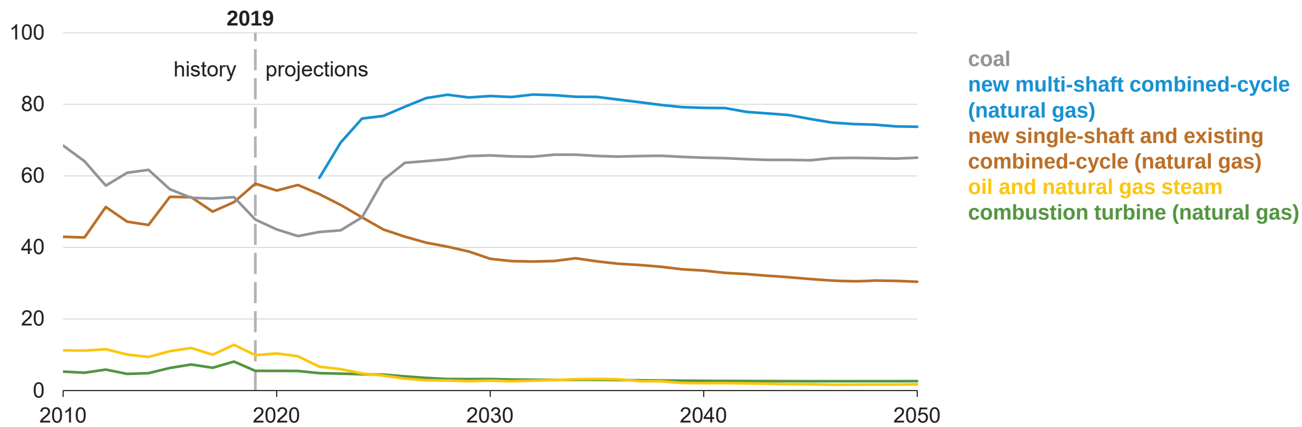
Coal production decreases through 2025 due to retiring coal-fired electric generating capacity, but federal rule compliance and higher natural gas prices lead to coal production leveling off afterwards

AEO2020 coal production by region
million short tons



Lower operating costs and higher efficiencies result in advanced natural gas-fired combined-cycle capacity factors of 80% by 2030 in the AEO2020 Reference case—

Capacity factor for fossil-fired plants (AEO2020 Reference case)
percent



—but then decline over time as natural gas prices increase and renewable generation grows

- Lower natural gas prices and reduced capital costs for new natural gas-fired combined-cycle generating units change fossil fuel electric generation use during the next decade in the AEO2020 Reference Case. Beginning in 2022—the first year of availability—new, multi-shaft (2 x 2 x 1 configuration) combined-cycle natural gas-fired units have the highest projected capacity factors of all technologies, averaging 81% between 2025 and 2035. The currently most common combined-cycle units, with their lower efficiency, and the new single-shaft (1 x 1 x 1 configuration) combined-cycle units decline in utilization as a group, from 56% in 2020 to 36% by 2035.

- After 2035, capacity factors for both combined-cycle technologies decline gradually, in part because large increases in intermittent generation through 2050 alter the dispatch patterns and requirements for fossil fuel-fired generation.

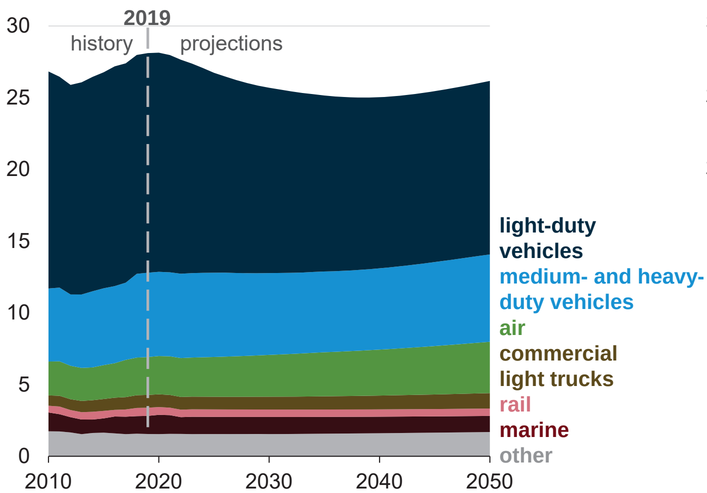
- The utilization rate of coal plants has fallen significantly in recent years as declining natural gas prices have led to a shift in economics between existing coal-fired and natural gas-fired combined-cycle generators. In 2019, the average capacity factor of the U.S. coal-fired fleet was 48% compared with an average natural gas-fired combined-cycle capacity factor of 58%. The low capacity factor for coal plants reflects a certain amount of idled inefficient capacity, which the Reference case projects will retire by 2025 as a result of the ACE rule. After 2025, the installed coal-fired capacity level is much lower because only the most efficient plants remain online. As a result, the average capacity factor for the fleet recovers quickly and stabilizes at about 65%.

Transportation

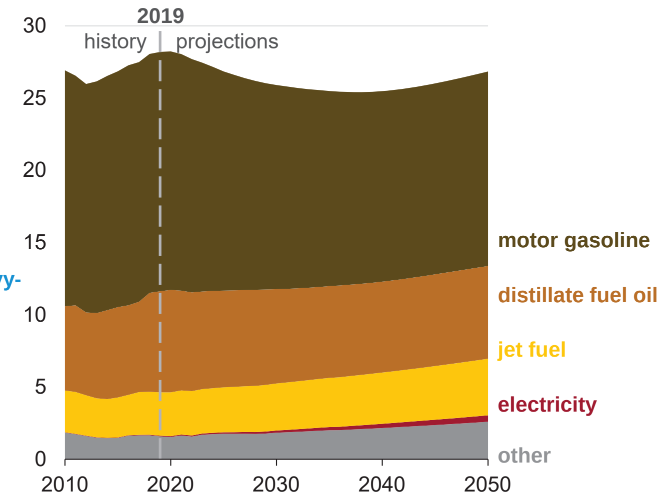
Transportation energy consumption peaks in 2020 in the AEO2020 Reference case because rising fuel efficiency more than offsets the effects of increases in total travel and freight movements, but this trend reverses toward the end of the projection period.

Transportation energy consumption declines through the 2030s in the AEO2020 Reference case—

Transportation sector consumption (by type)
(AEO2020 Reference case)
quadrillion British thermal units



Transportation sector consumption (by fuel)
(AEO2020 Reference case)
quadrillion British thermal units

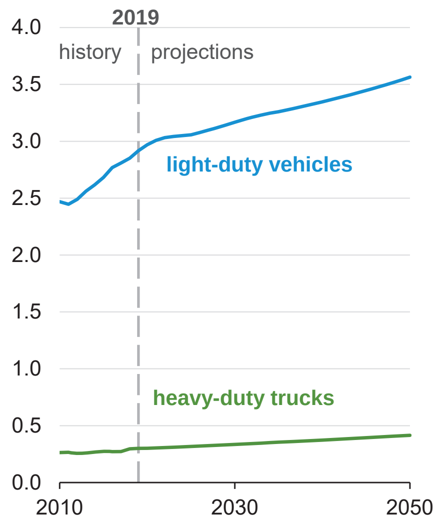


—because increases in fuel economy more than offset growth in vehicle miles traveled

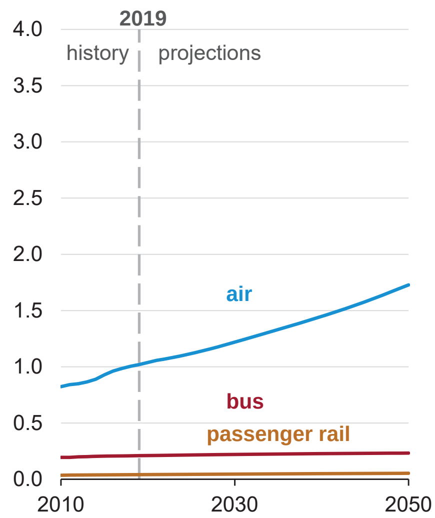
- Increases in fuel economy standards drive the decrease in U.S. motor gasoline consumption, which declines by 19% through 2050.
- Continued growth of on-road travel increases energy use later in the projection period because the travel demand for both light- and heavy-duty vehicles outpaces fuel economy improvements that result from regulatory requirements. Fuel efficiency regulations require no additional efficiency increases for new light-duty vehicles after 2025 and for new heavy-duty vehicles after 2027.
- Although increases in fuel efficiency standards slow growth in heavy-duty vehicle energy consumption and related diesel use, overall energy consumption for heavy-duty vehicles increases 4% through 2050 as a result of rising economic activity that increases demand for freight truck travel.
- Electricity is the fastest-growing energy source in the transportation sector, increasing on average 7.4% per year by 2050 as a result of increased demand for electric light-duty vehicles. Despite this growth, electricity accounts for less than 2% of transportation fuel consumption in 2050.
- Jet fuel consumption also increases through the projection period, rising 31% by 2050 because increases in air transportation outpace increases in aircraft fuel efficiency.
- Motor gasoline and distillate fuel oil’s combined share of total transportation energy consumption decreases from 84% in 2019 to 74% in 2050.

Passenger travel increases across all transportation modes in the AEO2020 Reference case through 2050—

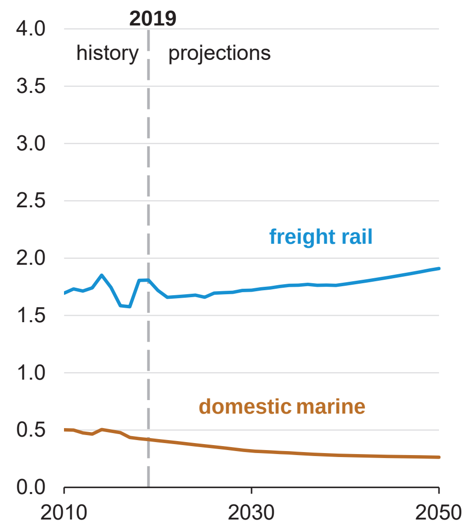
Vehicle travel
(AEO2020 Reference case)
trillion vehicle miles



Passenger travel
(AEO2020 Reference case)
trillion revenue passenger miles



Rail and domestic shipping
(AEO2020 Reference case)
trillion ton-miles traveled

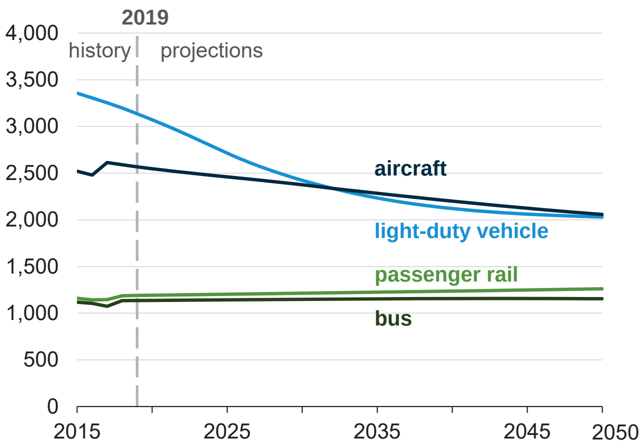


—and freight movement increases across all modes except domestic marine

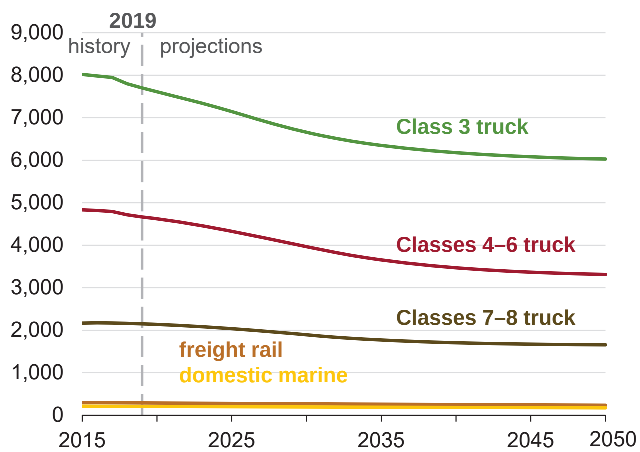
- Light-duty vehicle miles traveled increase by 22% in the AEO2020 Reference case, growing from 2.9 trillion miles in 2019 to 3.6 trillion miles in 2050 as a result of rising incomes and growing population.
- Truck vehicle miles traveled, the dominant mode of freight movement in the United States, grow by 38%, from 300 billion miles in 2019 to 415 billion miles in 2050, as a result of increased economic activity. Freight rail ton-miles decline significantly in the early part of the projection period as a result of reduced U.S. coal shipments, but overall, freight rail ton-miles grow by 6% during the projection period, led primarily by rising industrial output.
- Air travel grows 70% from 1,020 billion revenue passenger miles to 1,729 billion revenue passenger miles through the projection period in the Reference case because of increased demand for global connectivity and rising personal incomes. Bus and passenger rail travel increase 11% and 30%, respectively.
- Domestic marine shipments decline modestly during the projection period, continuing a historical trend related to logistical and economic competition with other freight modes.

Energy intensity decreases across most transportation modes in the AEO2020 Reference case—

Passenger mode energy intensity (AEO2020 Reference case)
British thermal units per passenger-mile



Freight mode energy intensity (AEO2020 Reference case)
British thermal units per ton-mile



—because of policy, economic, and technological factors

- Energy use per passenger-mile of travel in light-duty vehicles declines nearly 35% by 2050 in the AEO2020 Reference case as newer, more fuel-efficient vehicles enter the market, including both more efficient conventional gasoline vehicles and highly efficient alternatives such as battery electric vehicles. Energy efficiencies for light-duty vehicles are affected by current federal fuel economy and greenhouse gas emissions standards.

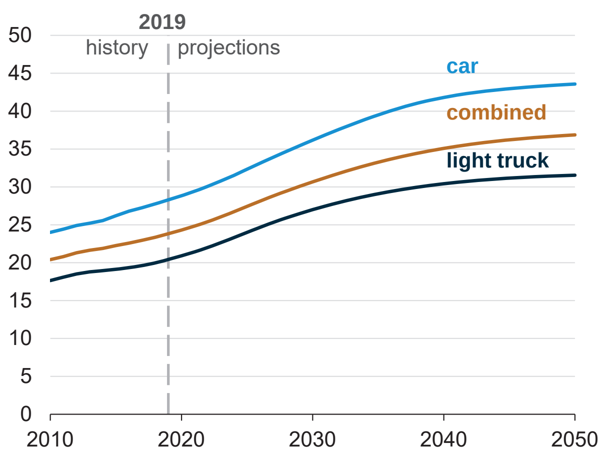
- Energy use per passenger-mile of travel in aircraft decreases because of the economically driven adoption of energy-efficient technology and practices. Energy use per passenger-mile of travel on passenger rail and buses, already relatively energy-efficient modes of travel per passenger-mile, remains relatively constant.

- Energy use per ton-mile of travel by freight modes decreases, led by increases in the fuel economy of heavy-duty trucks across all weight classes as the second phase of heavy-duty vehicle efficiency and greenhouse gas standards take full effect in 2027.

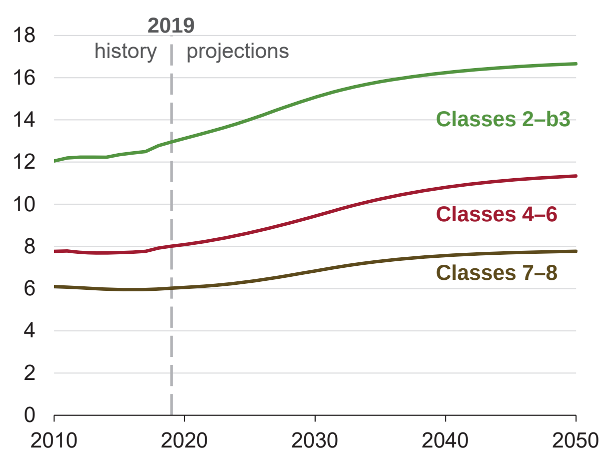
- Gains in energy efficiency offset increases in travel for passenger and freight modes. These efficiency gains decrease energy consumption by light-duty vehicles in the projection period and temper the rise in energy consumption by other transportation modes.

Fuel economy of all on-road vehicles increases in the AEO2020 Reference case—

Light–duty fuel economy (AEO2020 Reference case)
miles per gallon (all vehicles)



Heavy–duty fuel economy (AEO2020 Reference case)
miles per gallon (all vehicles)



—across all vehicle types throughout the projection period

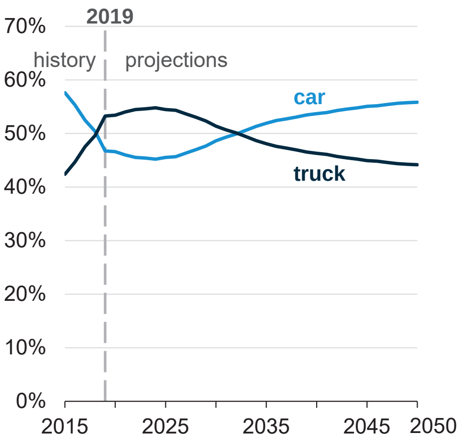
- Across all light-duty vehicles in use, fuel economy increases by 55% by 2050 in the AEO2020 Reference case as newer, more fuel-efficient vehicles enter the market and cars, which are more fuel efficient than light trucks, gain market share during the projection period. The fuel economy of cars increases from 28.3 miles per gallon (mpg) to 43.6 mpg, and the fuel economy for new light trucks increases from 20.4 mpg to 31.6 mpg.

- Fuel economy of the heavy-duty vehicles in use improves across all weight classes as the efficiency improvements required under the second phase of heavy-duty vehicle efficiency and greenhouse gas standards take full effect. Phase II of the heavy-duty vehicle efficiency and greenhouse gas standards reaches the maximum requirements in 2027. Heavy-duty vehicle fuel economy continues to improve as older vehicles are replaced with newer, more efficient vehicles.

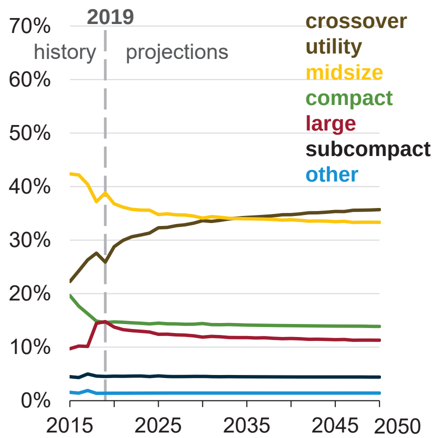
- Gains in fuel economy temper heavy-duty vehicle energy consumption growth and decrease light-duty vehicle energy consumption. For heavy-duty vehicles after 2040, increasing vehicle travel outweighs fuel economy improvements, leading to increases in fuel demand.

Sales of more fuel-efficient cars and light-truck crossover utility vehicles increase in the AEO2020 Reference case—

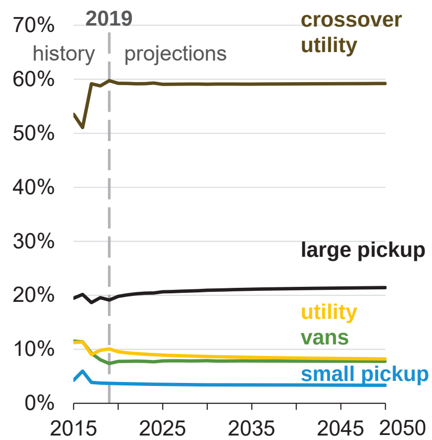
Light-duty vehicle sales shares (AEO2020 Reference case)
percent



Car sales shares by size class (AEO2020 Reference case)
percent



Light truck sales shares by size class (AEO2020 Reference case)
percent



—but other vehicle types maintain significant market share through 2050

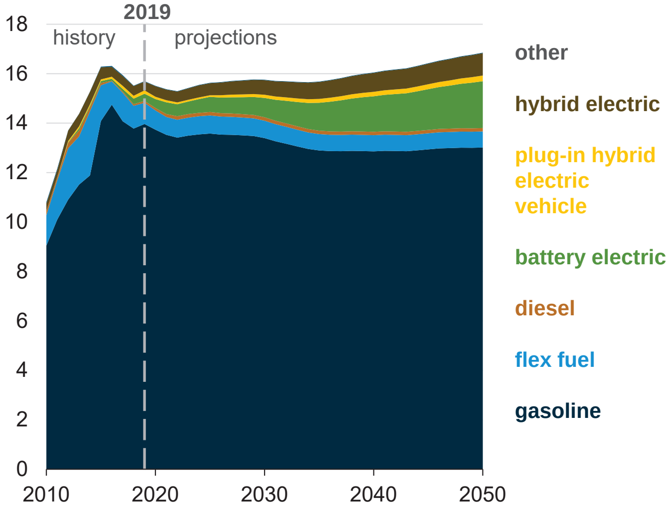
- In the AEO2020 Reference case, passenger cars gain market share in the light-duty vehicle market relative to light-duty trucks because they have higher fuel efficiency in periods when motor gasoline prices increase. They also gain market share because crossover utility vehicles, often classified as passenger cars, may replace lower fuel economy light-truck classified utility vehicles as a result of increasing availability and popularity.

- Light trucks lose some of their share in the light-duty vehicle market, and in terms of number of units sold, the classifications within light trucks shift from traditional vans and utility vehicles toward crossover utility vehicles that have higher fuel economy.

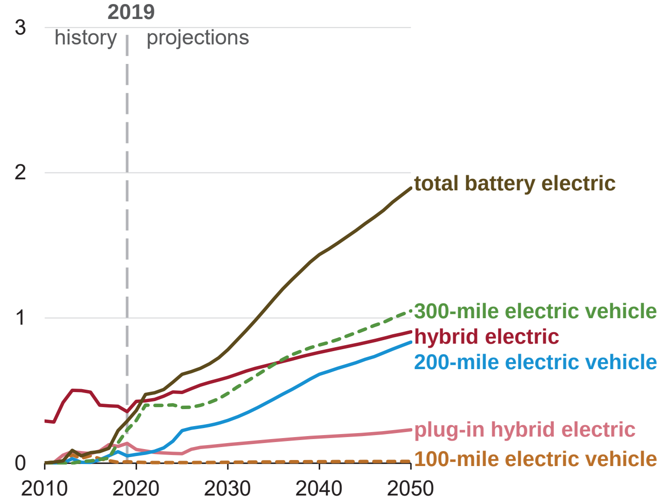
- Combined car and light-truck classified crossover utility vehicles reach 46% of new light-duty vehicle sales in 2050, largely taking away sales from traditional compact, midsize, and large cars and from truck-based sport utility vehicles.

Alternative and electric vehicles gain market share in the AEO2020 Reference case—

Light-duty vehicle sales by fuel type (AEO2020 Reference case)
millions of vehicles



New vehicle sales of battery powered vehicles (AEO2020 Reference case)
millions of vehicles

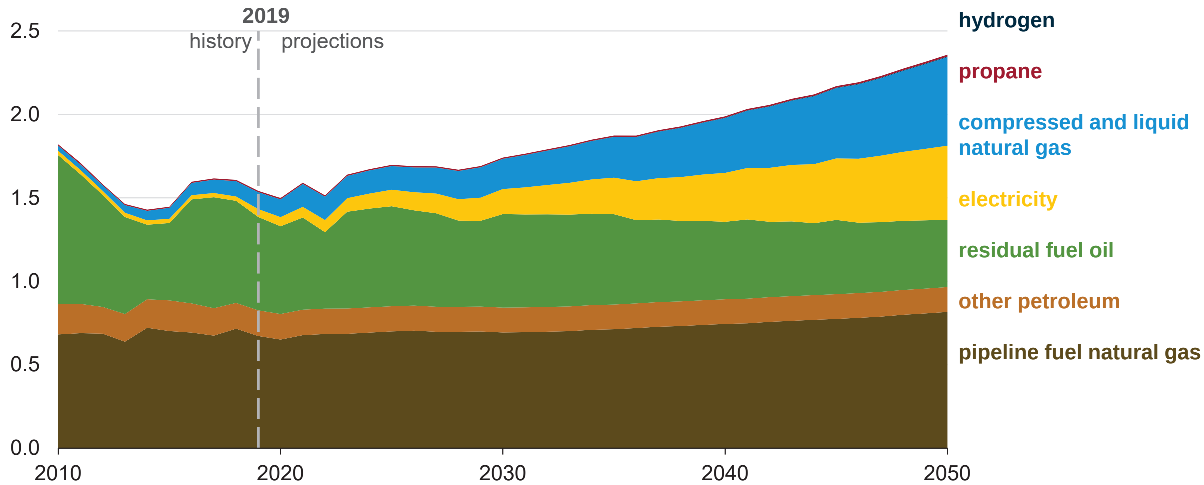


—but gasoline vehicles remain the dominant vehicle type through 2050

- The combined share of sales from gasoline and flex-fuel vehicles (which use gasoline blended with up to 85% ethanol) declines from 94% in 2019 to 81% in 2050 in the AEO2020 Reference case because of growth in sales of battery electric vehicles (BEV), plug-in hybrid electric vehicles (PHEV), and hybrid electric vehicles. BEV sales increase faster than any other type of vehicle sale, growing on average by 6% per year.
- Sales of the longer-ranged 200- and 300-mile BEVs grow during the entire projection period, tempering sales of the shorter-range 100-mile BEV and PHEV. Sales for the 200- and 300-mile BEVs increase from 280,000 in 2019 to 1.9 million in 2050, while sales of PHEVs increase from 137,000 in 2019 to 230,000 in 2050.
- Hybrid electric vehicle sales increase 3.1% per year, rising to more than 900,000 new vehicles sold by the end of the projection period.
- New light-duty vehicles of all fuel types show significant improvements in fuel economy because of compliance with increasing fuel economy standards. Light-duty vehicle fuel economy rises by 55% through the projection period.

Consumption of transportation fuels grows considerably in the AEO2020 Reference case through the projection period—

Transportation sector consumption of minor petroleum and alternative fuels (AEO2020 Reference case)
quadrillion British thermal units



—because of increased use of electricity and natural gas

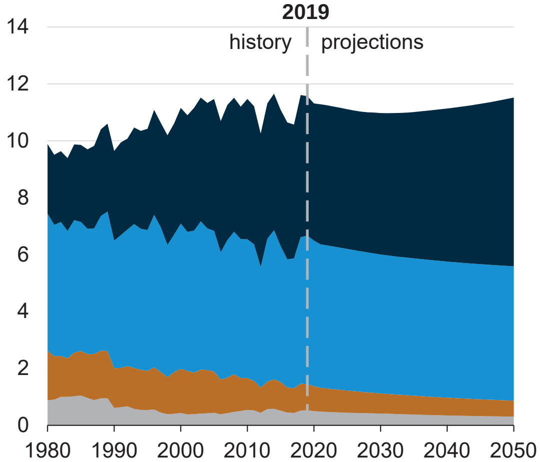
- Electricity use in the transportation sector increases sharply after 2020 in the AEO2020 Reference case because of a rise in the sale of new battery-electric and plug-in hybrid-electric light-duty vehicles.
- Natural gas consumption increases through 2050 because natural gas is increasingly used as a fuel for heavy-duty vehicles and freight rail.
- In the later years of the projection period, liquefied natural gas is used in the maritime industry as an alternative to burning high-sulfur residual fuel oil to meet the new standards set for marine fuels under the International Convention for the Prevention of Pollution from Ships (MARPOL convention).

Buildings

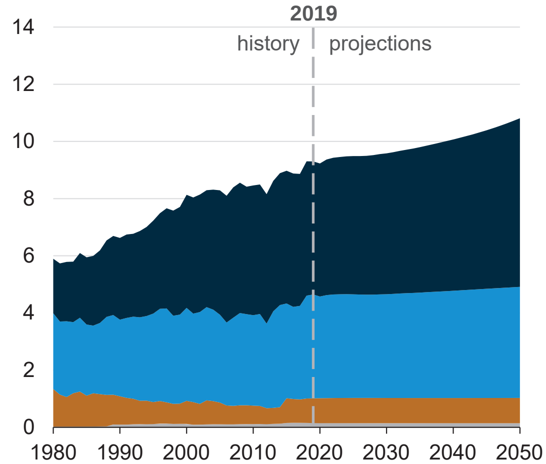
Delivered energy consumption in the U.S. buildings sector grows gradually from 2019 to 2050 in the Reference case, based, in part, on currently established efficiency standards and incentives. EIA anticipates distributed solar capacity to grow throughout the projection period based on near-term incentives, declining costs, and demographic factors.

Residential and commercial energy consumption grows slowly in the AEO2020 Reference case—

Residential sector delivered energy consumption (AEO2020 Reference case)
quadrillion British thermal units



Commercial sector delivered energy consumption (AEO2020 Reference case)
quadrillion British thermal units



electricity natural gas petroleum and other liquids other

—accounting for changes to energy efficiency standards and technological advances

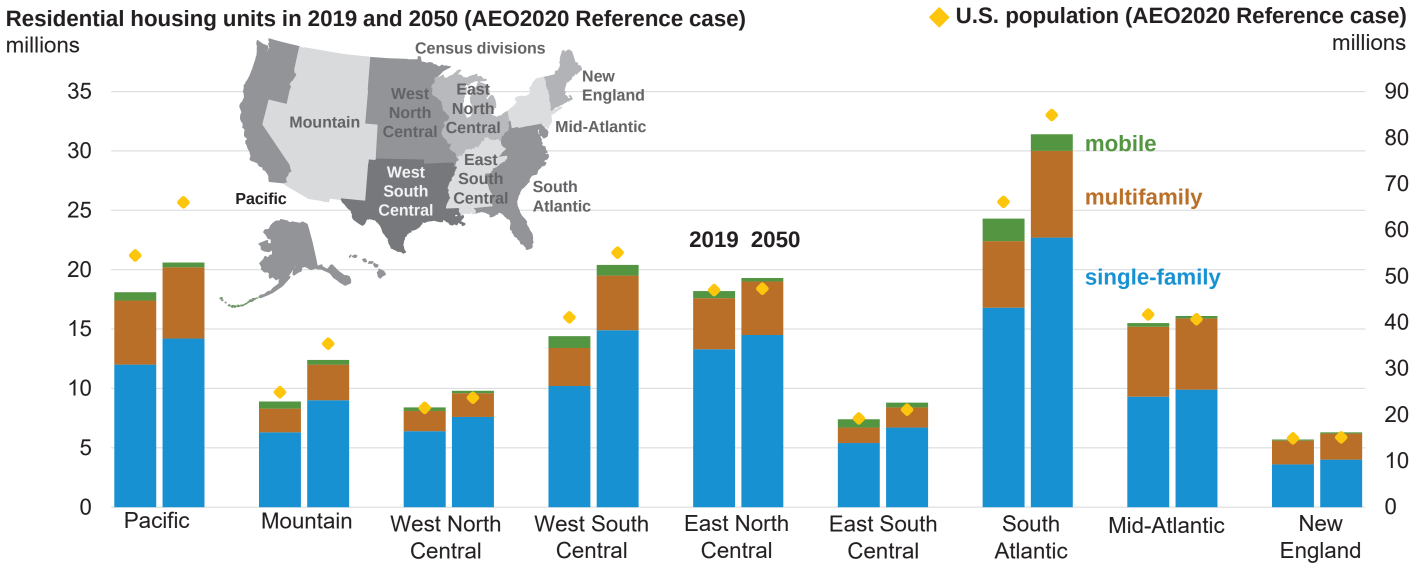
- Total delivered energy consumption in the U.S. buildings sector grows slowly through the AEO2020 Reference case projection period, 2019 to 2050, by 0.2% per year, as energy efficiency improvements, increases in distributed electricity generation, and regional shifts in the population partially offset the impacts of higher growth rates in population, number of households, and commercial floorspace.

- Purchased electricity consumption grows in both the residential and commercial sectors as a result of increased demand for appliances, devices, and equipment that use electricity. In the Reference case, purchased electricity increases by 0.6% and 0.8% per year in the residential and commercial sectors, respectively, through 2050.

- Natural gas consumption by commercial buildings grows by 0.2% per year through the projection period, led by increases in water heating and cooking. Consumption of natural gas in the residential sector falls by 0.3% per year as its use for space heating continues to decline.

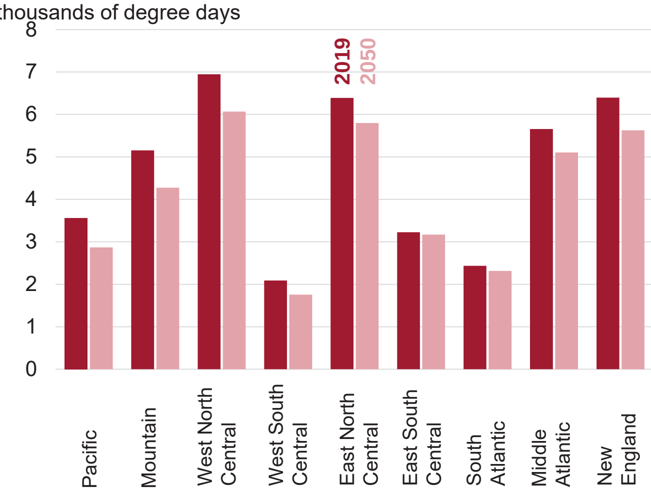
- If not for the contribution of distributed generation sources, particularly rooftop solar, purchased electricity consumption in residential and commercial buildings would be 5% and 3% higher, respectively, by the end of the projection period.

Population and residential housing stocks continue to grow mostly in the South and West between 2019 and 2050

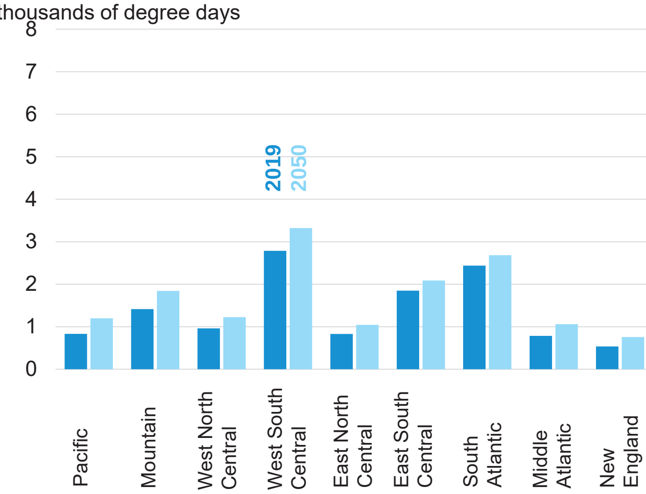


As a result of population shifts, overall U.S. heating needs decrease and cooling needs increase—

Population-weighted heating degree days by census division (AEO2020 Reference case)
thousands of degree days



Population-weighted cooling degree days by census division (AEO2020 Reference case)
thousands of degree days



—especially in warmer regions with higher space cooling demand

- The number of U.S. households increases by an average of 0.6% per year in the AEO2020 Reference case through 2050, and single-family homes grow the fastest, at 0.7% per year. The stock of multifamily homes grows at a rate of 0.6% per year, while mobile home stocks decrease by 1.2% per year and are the only category EIA does not expect to grow.

- Cooling-dominated West South Central and South Atlantic Census Divisions—as well as the Mountain Census Division—experience average annual housing stock growth that exceeds the national average. 12.2 million housing units are added across these areas by 2050.

- The size of housing units also continues to grow; the national average floorspace per home increases 0.3% per year from 1,786 square feet in 2019 to 1,987 square feet in 2050.

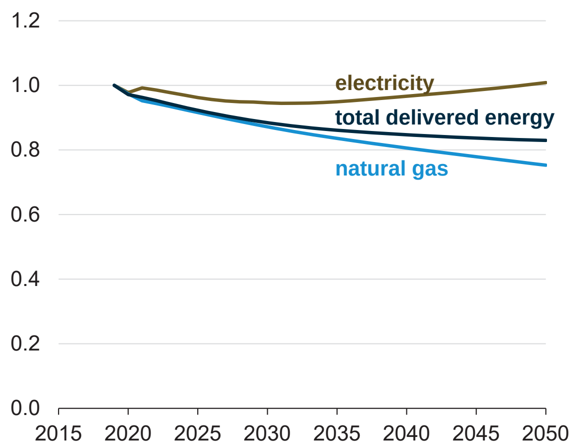
- Demand for space heating from fuels such as natural gas, distillate fuel oil, propane, and electricity decreases through 2050 as a result of fewer heating degree days (HDDs)—a measure of how cold a location is over a time period relative to a base temperature.

- Demand for space cooling from electricity increases through 2050 as a result of more cooling degree days (CDDs)—a measure of how warm a location is over a time period relative to a base temperature.

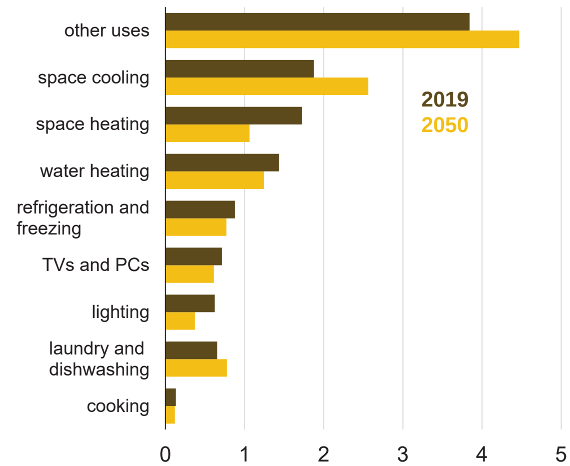
- EIA uses historical and near-term forecast HDDs and CDDs sourced from the National Oceanic and Atmospheric Administration. EIA uses this historical data and population projections to develop a 30-year linear trend for projecting population-weighted HDDs and CDDs.

U.S. residential energy intensity decreases in the AEO2020 Reference case—

Residential delivered energy intensity index (AEO2020 Reference case)
indexed annual energy use per household, 2019 = 1.0



Residential purchased electricity intensity (AEO2020 Reference case)
thousand kilowatthours per household



—although changes in electricity consumption vary by end use

- In the AEO2020 Reference case, U.S. total delivered residential energy intensity, defined as annual delivered energy use per household, decreases by 17% between 2019 and 2050 as the number of households grows faster than energy use. The main factors contributing to this decline include gains in appliance efficiency, onsite electricity generation (e.g., solar photovoltaic), utility energy efficiency rebates, rising residential natural gas prices, lower space heating demand, and a continued population shift to warmer regions.

- Lighting electricity consumption per U.S. household declines faster than other electric end uses as a result of compliance with the minimum performance requirements of the Energy Independence and Security Act of 2007. The federal standards effectively eliminate low-efficacy incandescent lamps, replacing them with more energy-efficient light-emitting diodes (LEDs) and compact fluorescent lamps (CFLs) by 2020. Energy efficiency incentives also accelerate LED and CFL penetration before 2020. In 2050, purchased electricity intensity for lighting is 40% lower than in 2019.

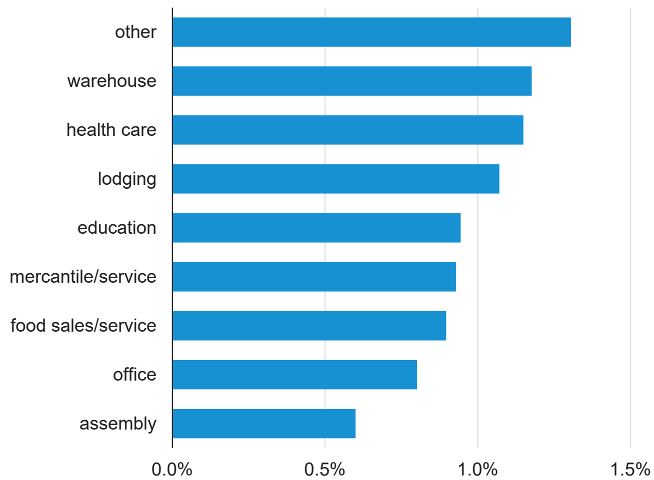
- As near-term appliance standards result in efficiency gains beyond those gains caused by market forces and technological change, electricity intensity declines before 2030 and then increases slightly as sector growth overtakes additional efficiency gains.

- Natural gas and electric equipment increasingly replace distillate fuel oil- and propane-fired equipment.

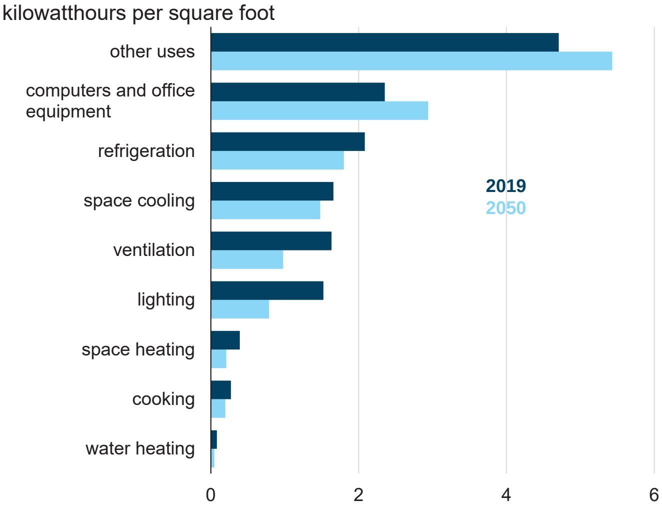
- Electricity intensity of other uses increases throughout the projection period with expected growth in the use of electronic equipment, such as security systems and rechargeable devices.

AEO2020 Reference case U.S. commercial energy consumption growth is tempered by increased equipment and lighting efficiencies—

Commercial floorspace growth (AEO2020 Reference case)
percent compound annual growth rate



Commercial purchased electricity intensity (AEO2020 Reference case)
kilowatthours per square foot

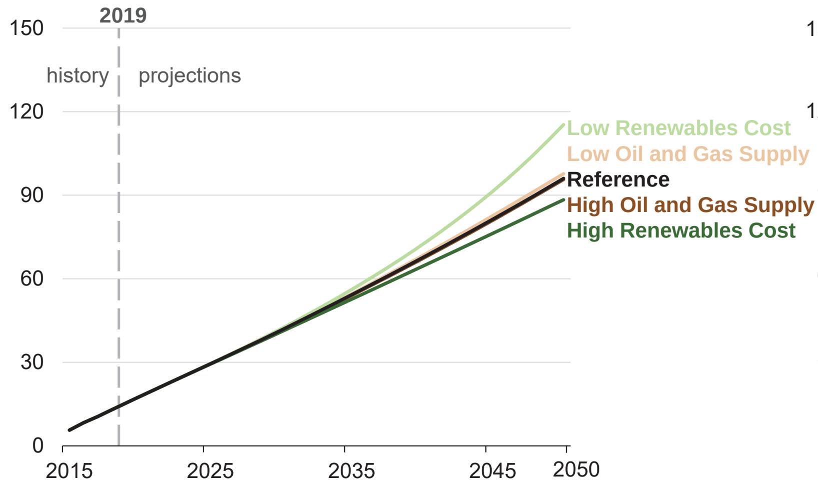


—but growing floorspace, declining electricity prices, and expanding information technology needs drive an overall increase in electricity consumption

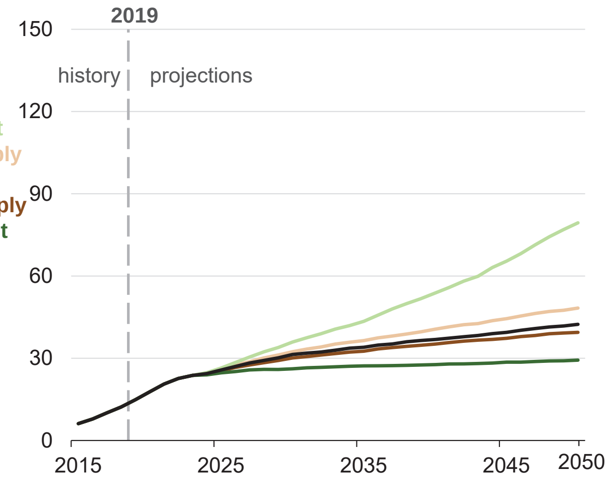
- Commercial floorspace grows by an average 1% per year in the AEO2020 Reference case through the projection period, reflecting rising economic activity. Some of the fastest-growing building types, including health care and lodging, are also among the most energy intensive.
- Commercial electricity intensity, defined as electricity consumption per square foot of commercial floorspace, declines at an average of 0.2% per year through the projection period. Combined with floorspace growth, the decline in intensity results in an overall increase in electricity consumption of 0.8% per year.
- Lighting accounts for the steepest intensity decline among the major end uses, falling by more than 2% per year throughout the projection period. Lower costs and energy efficiency incentives lead efficient LEDs to displace linear fluorescent lighting as the dominant commercial lighting technology by 2030. Similarly, intensities for major end uses such as ventilation, space heating and cooling, and refrigeration decline over time. However, other uses such as office equipment (not including computers), whose electricity intensity increases by 1.6% per year, counterbalance these declines.
- Despite increasing equipment efficiencies, declining electricity prices encourage greater use of energy-consuming appliances and devices.

Rooftop solar PV adoption grows between 2019 and 2050—

Residential solar distributed generation capacity
gigawatts direct current



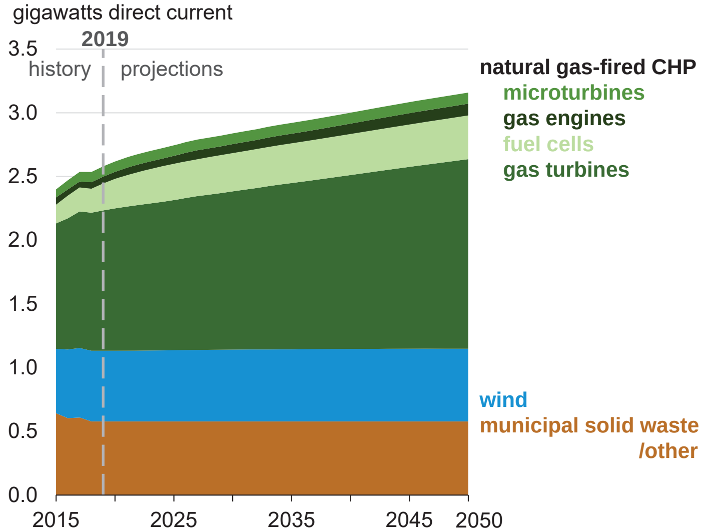
Commercial solar distributed generation capacity
gigawatts direct current

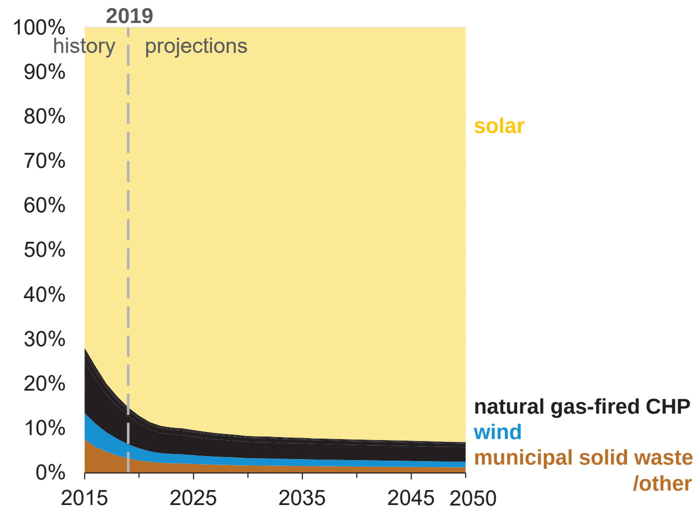


—with residential growth outpacing commercial growth in later years

- Residential solar photovoltaic (PV) capacity increases by an average of 6.1% per year through 2050 in the AEO2020 Reference case, and commercial PV capacity increases by an average of 3.4% per year.
- PV costs decline most rapidly before 2030, despite the phasedown in the federal Energy Investment Tax Credit (ITC) from 30% in 2019 to 10% in 2022 and the four-year Section 201 tariff levied on PV cells and modules in 2018.
- Declining installation costs drive steady commercial PV adoption, although capacity growth slows after 2030. Rising incomes, declining system costs, and social influences accelerate residential PV adoption.
- For both residential and commercial sectors, the High Renewables Cost case and Low Renewables Cost case vary the most from the Reference case. Commercial PV projections are particularly responsive to variations in installed cost; a spread of 50 GW between the Low Renewables Cost case and High Renewables Cost case is projected in 2050.
- PV growth is also sensitive to electricity prices. In 2050, electricity prices vary the most from the AEO2020 Reference case in the Low Oil and Gas Supply case, by 9.7% and 9.2% for the residential and commercial sectors, respectively. In response, residential PV capacity increases by 1.7% and commercial PV capacity increase by 14% relative to the AEO2020 Reference case.

Combined heat and power (CHP) and other non-solar sources of electric generation account for 15% of commercial onsite capacity in 2019 in the AEO2020 Reference case—

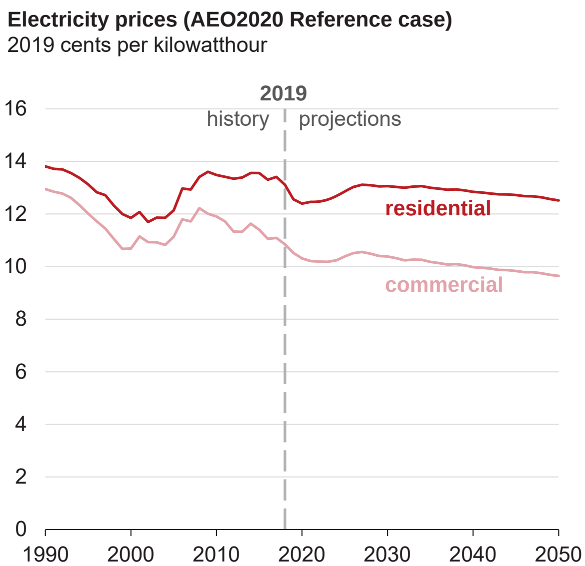


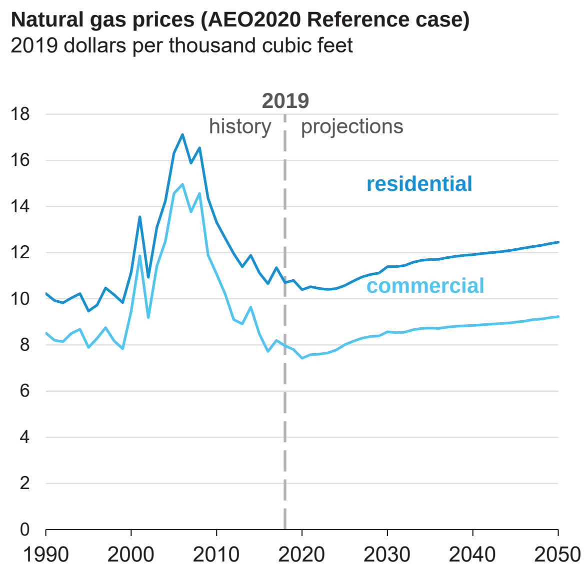


—but this share declines during the projection period as growth lags behind solar photovoltaic generation

- Non-photovoltaic technologies, such as combined heat and power (CHP) and distributed wind, account for 15% of commercial distributed generation capacity in 2019 but only 7% by 2050 in the AEO2020 Reference case.
- Of the non-solar technologies, natural gas-fired CHP (namely, microturbine, reciprocating engine, fuel cell, and conventional turbine) capacity expands the fastest at an average of 1.1% per year. Incremental installed cost declines and performance improvements drive this growth, despite rising commercial natural gas prices, which increase by 0.5% per year through the projection period.
- The 2018 Bipartisan Budget Act extends the ITC provisions for qualifying CHP beginning construction before January 1, 2022. These tax credits contribute to growth in CHP in the short term.
- Wind generation capacity projections remain flat in AEO2020, in part, because of a lack of commercial mid-scale turbines (101 kilowatts to 1 megawatt) available in the U.S. market. The majority of recent commercial wind installations use large-scale turbines—the average in 2018 was 2.1 megawatts—but the commercial sector market potential for these larger turbines is limited.

Residential and commercial electricity prices decline slightly in the AEO2020 Reference case through 2050





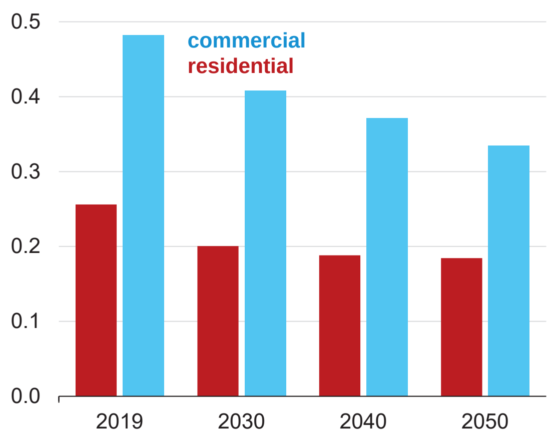
—while natural gas prices rise, moderating natural gas consumption

- AEO2020 Reference case electricity prices fall in the near term, primarily because utilities pass along savings from lower taxes under the Tax Cuts and Jobs Act of 2017. In addition, utilities are replacing more costly power plants with new plants that are less expensive to construct and operate, which also contributes to lower prices. Lower prices encourage more consumption in the near term in both sectors, although near-term efficiency standards and population shifts to warmer areas of the country moderate this trend.

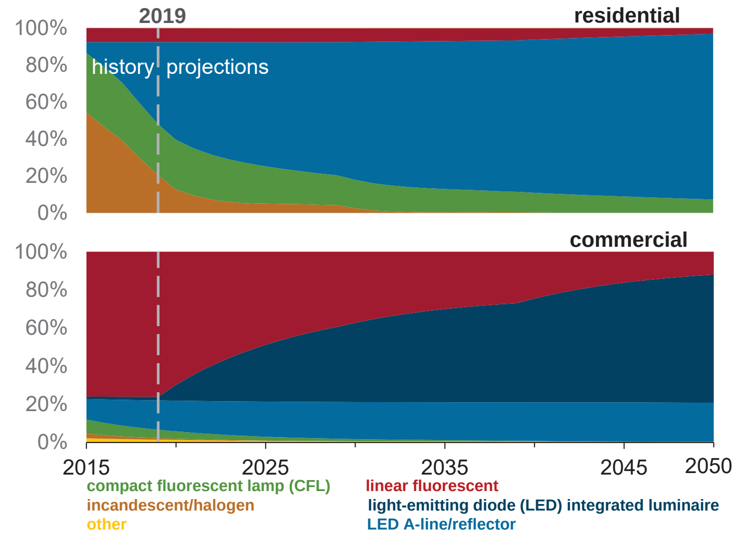
- Natural gas prices in both the residential and commercial sectors increase steadily, by an average of 0.5% per year, in the Reference case through 2050. Increasing natural gas prices decrease consumption in the residential sector and moderate consumption growth in the commercial sector.

Energy consumed to meet lighting needs decreases in the AEO2020 Reference case –

Delivered electricity consumed to meet lighting demand (AEO2020 Reference case)
quadrillion British thermal units



Lighting shares (AEO2020 Reference case)
percent



—driven by federal efficiency standards, declining upfront costs, and utility and state energy efficiency program incentives

- In 2019, 44% of residential light bulbs were LEDs, currently the most efficient light bulb technology available, and 17% of commercial lighting service demand was met by LED bulbs and fixtures. By 2050, these shares increase to 90% and 88%, respectively.

- Utility energy efficiency program incentives drive LED adoption in the AEO2020 Reference case during the short to medium term, reducing the upfront cost of purchasing LEDs by up to 40% until 2019. EIA assumes residential lighting subsidies will fall to 0% in 2020, but efficiency incentives continue to drive commercial adoption of LED lighting through 2029.

- Efficiency requirements under the Energy Independence and Security Act of 2007 eliminate inefficient incandescent bulbs from general service lighting (GSL) use after 2020, causing homes and businesses to switch to more efficient LED and CFL bulbs. Although we incorporate a U.S. Department of Energy final rule that narrows the definition of GSLs, about two-thirds of residential lighting falls under the revised definition.

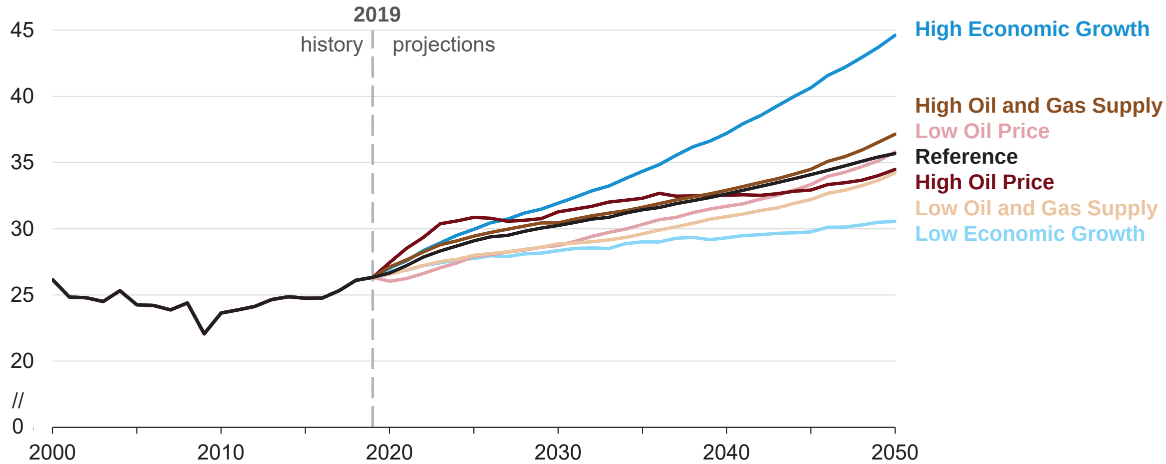
- Cost declines in LEDs drive expanded market share throughout the projection period. During the projection period, the AEO2020 shows the installed cost of residential GSL LEDs declines by 33% and the cost of commercial LED luminaires declines by up to 74%.

Industrial

As a result of projected economic growth and lower domestic energy prices relative to the world market, AEO2020 projects that energy consumption in the U.S. industrial sector will increase during the projection period across all cases. U.S. consumption of most energy sources, particularly natural gas, will increase significantly. Coal consumption, which flattens after 2020, is the only exception. Energy intensity declines across all cases as a result of technological improvements.

Consumption of delivered industrial energy grows in all AEO2020 cases—

AEO2020 industrial delivered energy consumption
quadrillion British thermal units

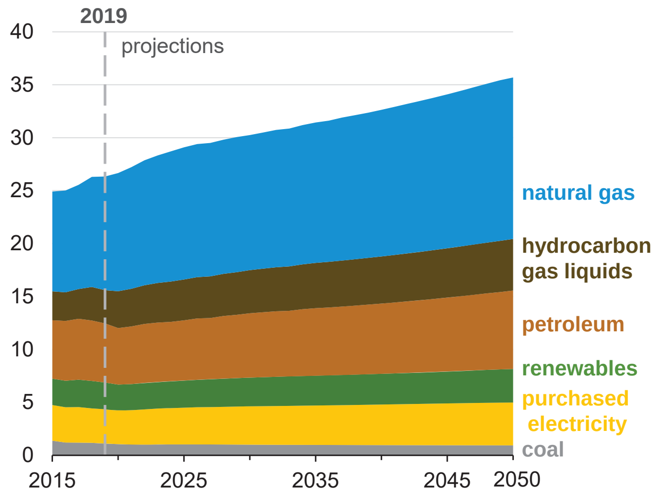


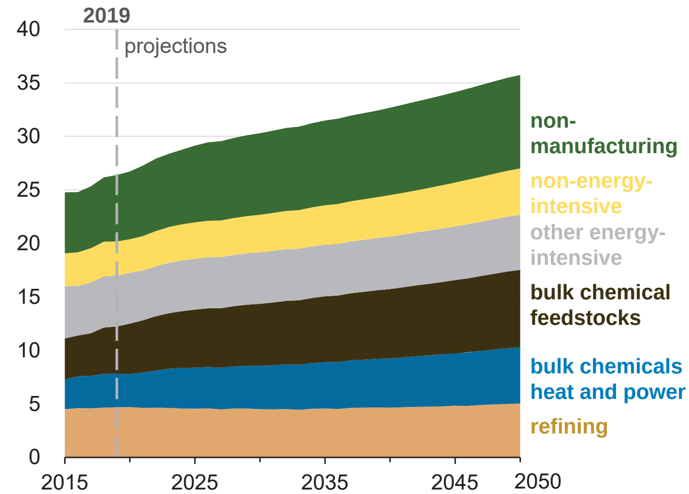
—driven by economic growth, but it is also affected by low prices and resource availability

- In the AEO2020 Reference case, U.S. delivered energy consumption in the industrial sector grows 36% from 26 quadrillion British thermal units (Btu) to 36 quadrillion Btu during the projection period.
- Industrial activity is closely correlated with economic activity. Therefore, changes in assumptions related to economic growth affect industrial sector energy consumption the most. The High Economic Growth case and the Low Economic Growth case vary the most from AEO2020 reference case projections of U.S. industrial sector energy consumption.
- Through the late 2020s, the High Oil Price case projects the fastest growth in industrial sector energy demand as a result of increased investment in the short term for more mining/oil extraction equipment and related activities (construction, cement, steel for drilling equipment, etc.). Eventually, higher oil prices dampen consumer spending in the long run, thereby lowering growth.
- Over the long term, industrial energy consumption is highest in the High Economic Growth case, reaching 45 quadrillion Btu in 2050, a 69% increase from 2019. With a faster growing economy, greater industrial activity in sectors such as food and fabricated metal products increases industrial energy use.
- Energy consumption in the High Oil and Gas Supply case is greater than in the Reference case as a result of increased crude oil and natural gas resources and improved extraction technologies that increase energy demand in the mining industry.

Industrial sector energy consumption increases fastest for natural gas and hydrocarbon gas liquids in the AEO2020 Reference case—

Industrial energy consumption by energy source and subsector (AEO2020 Reference case)
quadrillion British thermal units





—and bulk chemicals and nonmanufacturing are the fastest-growing industries in the sector

- Total U.S. industrial delivered energy consumption grows 1.0% per year on average during the projection period in the AEO2020 Reference case. Growth varies by fuel. EIA projects coal consumption to decline through the projection period, while natural gas and hydrocarbon gas liquids (HGL) consumption will grow fastest, reflecting strong supply growth and relatively low prices.

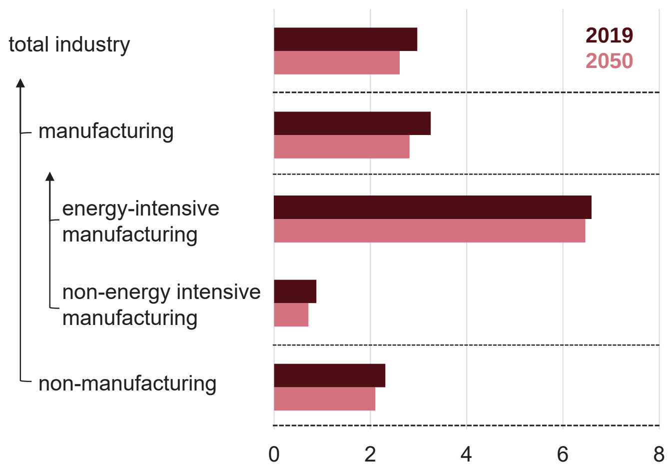
- During the projection period, industrial sector HGL consumption grows by 1.4% per year and natural gas consumption grows by 1.1% per year, as these fuels become more heavily used for heat and power and as feedstocks.

- Energy consumption in the bulk chemicals industry, including both heat and power and feedstocks, accounts for about 35% of total U.S. industrial energy consumption by the end of the projection period and grows at 1.6% per year.

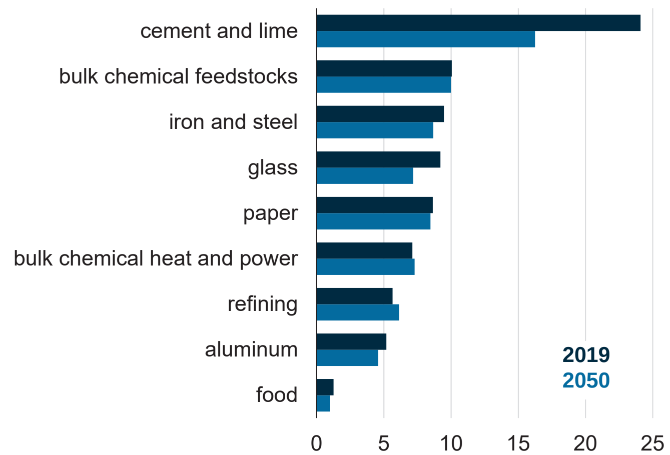
- Energy consumption in the other energy-intensive industries in the United States remains relatively flat during the projection period, growing on average 0.3% per year. Energy consumption in the iron and steel industry declines by 19% during the projection period, energy consumption in the paper industry increases by 11%, and energy consumption in the cement and lime industry consumption stays relatively flat.

In the AEO2020 Reference case, energy intensities decline in most heavy industries—

Energy intensity by subsector (AEO2020 Reference case)
trillion British thermal units per billion 2012 dollar shipments



Energy-intensive manufacturing (AEO2020 Reference case)
trillion British thermal units per billion 2012 dollar shipments



—reflecting industrial capital stock turnover and adoption of new, more energy-efficient technologies

- Energy intensity in the U.S. industrial sector (energy consumption per dollar of output) declines by 0.4% per year on average through 2050 in the AEO2020 Reference case. In manufacturing, energy intensity declines 0.5% per year through the projection period as a result of the increased energy efficiency of new capital equipment and the faster growth rate in non-energy-intensive manufacturing industries relative to energy-intensive manufacturing industries.

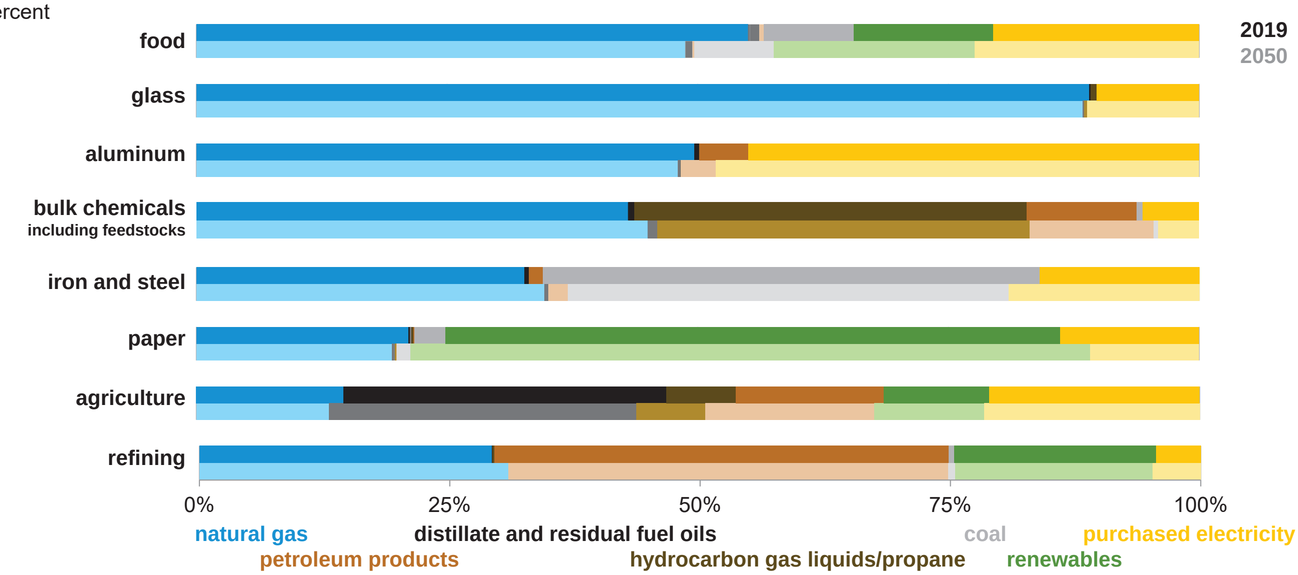
- Energy intensities in the refining sector and in the bulk chemical heat and power sector both increase as relatively low-cost natural gas increases production of lower-value commodities.

- Higher energy intensities in the refining sector and bulk chemical sector are offset by efficiency improvements in other energy-intensive industries, such as food (0.7% per year decline in energy intensity), glass (0.8% decline per year), and cement and lime (1.3% decline per year). The net result is an overall 2% decline in energy intensity for the energy-intensive manufacturing industries sector during the projection period.

- For some industries, large amounts of combined heat and power generation (CHP) may mask some efficiency gains. EIA includes CHP generation losses in industry energy consumption. Purchased electricity generation losses are accounted for in the electricity sector.

AEO2020 Reference case energy consumption by fuel varies across energy-intensive industries—

Energy consumption by energy source shares and industry (AEO2020 Reference case)
percent



—because some industries have greater capacity for fuel switching than others

- Natural gas (used primarily for process heat) remains the primary fuel in the U.S. food and glass industries in the AEO2020 Reference case, although its share declines through 2050. In the food industry, the share of renewables grows from 14% in 2019 to 20% in 2050. In the glass industry, natural gas continues to have the largest share, retaining more than an 88% share through the projection period.

- In the U.S. iron and steel industry, coal remains the primary fuel, although its share in the total energy mix for the sector declines from 50% in 2019 to 44% in 2050 as natural gas and electricity-fueled technologies become more widely used.

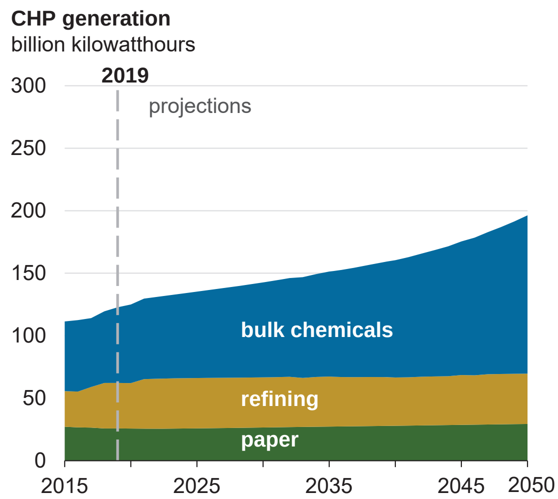
- The bulk chemicals industry consumes natural gas and HGLs for both heat and power and feedstock. The relatively low projected prices for both fuels result in continued high shares of total energy consumption and reduced shares of purchased electricity as CHP adoption grows.

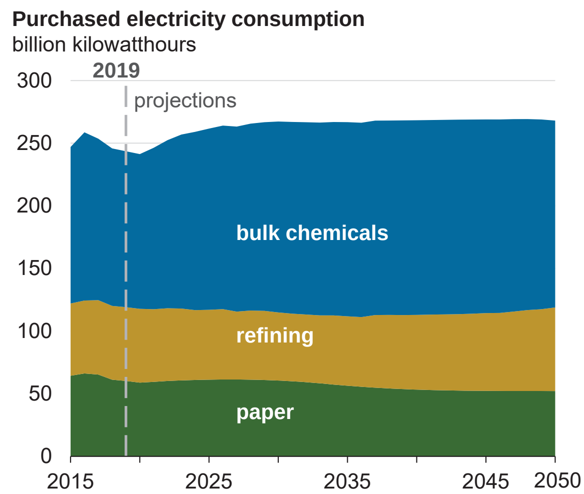
- In the United States, in addition to the food industry and, to some extent, refining (where bio-based feedstocks are used to produce blend-stocks for the transportation fuels sector), one of the highest shares of renewables consumption is in the paper industry, where black liquor (a byproduct of the pulping process) serves as a major fuel for boilers and on-site CHP. The renewables share of total energy consumed in the paper industry increases from 61% in 2019 to 68% in 2050.

- Petroleum remains the primary fuel for refining and for agriculture, where distillate fuels most of the on-field equipment.

Self-generation from combined heat and power (CHP), especially for bulk chemicals, accounts for most AEO2020 Reference case growth in industrial sector electricity consumption—

CHP generation and purchased electricity consumption for U.S. industries with the most installed CHP (AEO2020 Reference case)





—as quantities of purchased electricity remain fairly flat

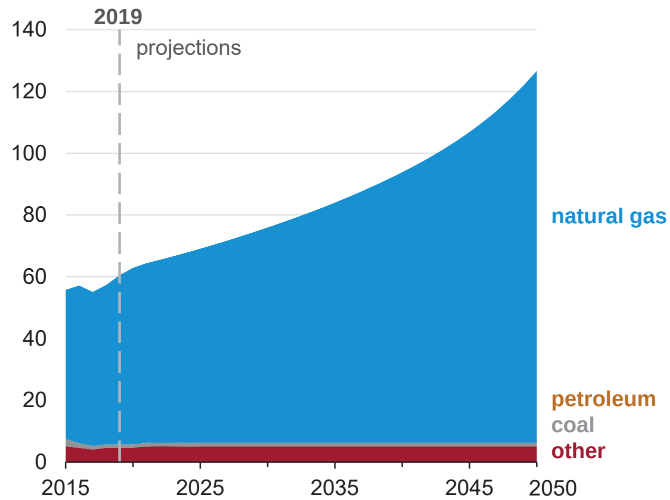
- AEO2020 Reference case electricity generation from CHP units in the U.S. bulk chemicals, refining, and paper industries (industries with the most CHP) grows 1.5% per year, from 125 billion kilowatthours (kWh) in 2019 to 196 billion kWh in 2050.

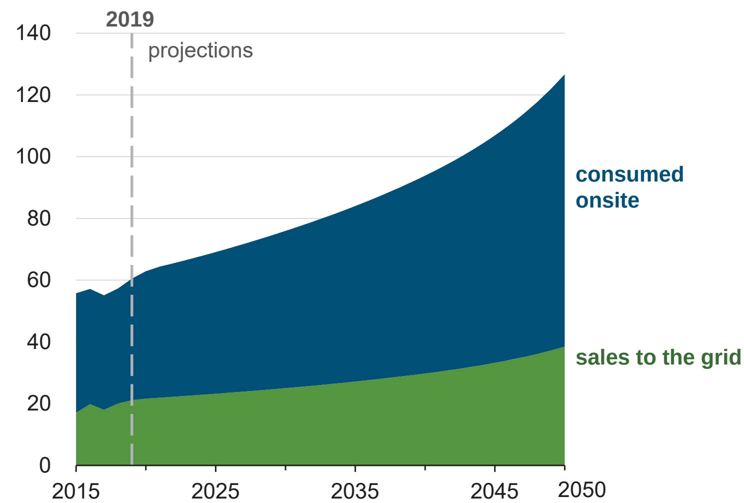
- The bulk chemical, refining, and paper industries use the most CHP in the United States because these large industries have high heating needs, and steam is readily available onsite to use for generation. The share of self-generated electricity to total electricity consumption in the sector rises from 34% in 2019 to 42% in 2050 because rapidly growing demand for industrial heat allows complementary power generation growth.

- Although natural gas accounts for more than 90% of the fuel used for CHP in the bulk chemicals industry in 2019 and 95% in 2050, petroleum products—in the form of residual oil, petroleum coke, and still gas and others—fuel some of the CHP capacity in the refining sector. In the paper industry, renewables such as black liquor fire CHP generation.

In the bulk chemicals industry, combined-heat-and-power (CHP) adoption grows in the AEO2020 Reference case; sales to the grid remain relatively flat as most generation fuels onsite consumption

Net CHP generation and disposition in the bulk chemicals sector, by fuel (AEO2020 Reference case)
billion kilowatthours



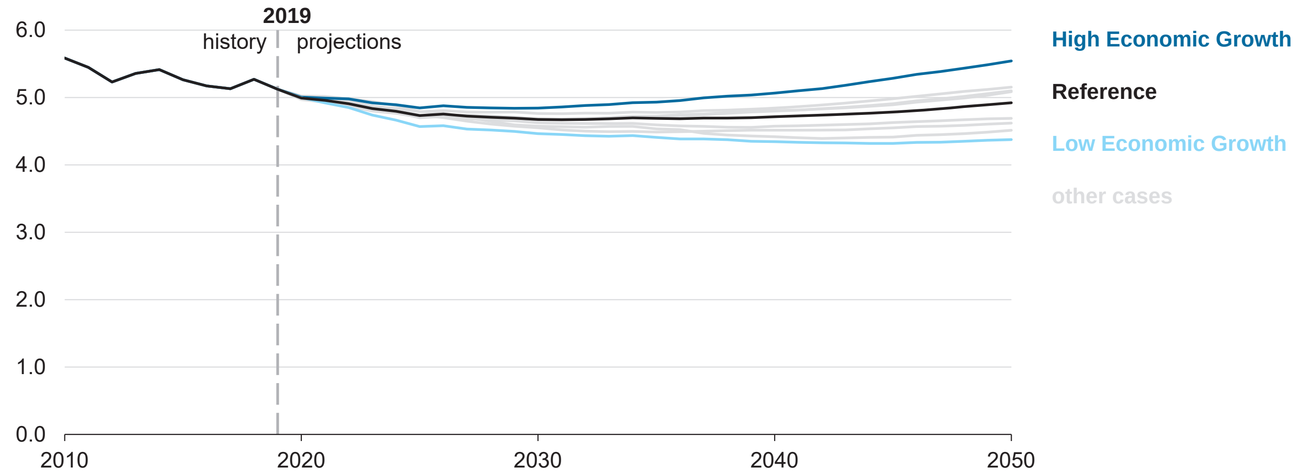


Emissions

Energy-related carbon dioxide emissions decrease until the mid-2020s in the AEO2020 Reference case as a result of changes in the fuel mix consumed by the electric power sector. After 2030, increases in energy demand in the other sectors—predominantly transportation and industrial—cause emissions to increase.

Economic growth is the biggest factor in carbon dioxide (CO2) emissions —

AEO2020 U.S. energy-related CO2 emissions cases
billion metric tons

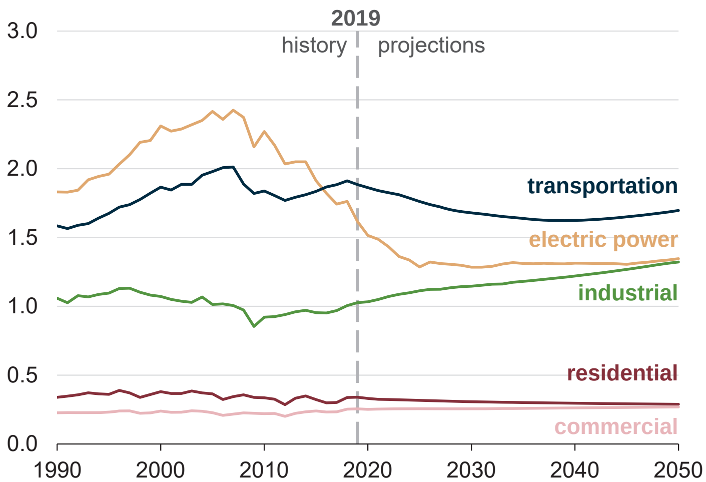


— and emissions in the High Economic Growth case rise faster than the Low Economic Growth case, as rapidly increasing energy demand outweighs improvements in efficiency

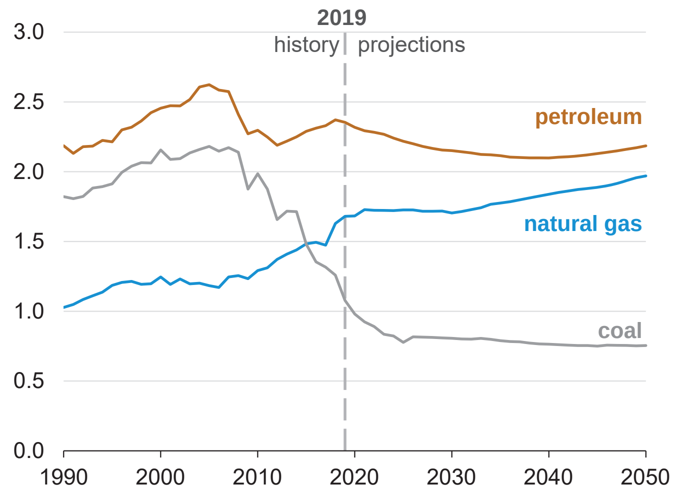
- Economic growth is the primary driver of energy demand and related CO2 emissions.
- Energy-related CO2 emissions in all AEO2020 cases decrease early in the projection period before increasing in the later years through 2050 as economic growth and increasing energy demand outweigh improvements in efficiency.
- In the High Economic Growth case, CO2 emissions decrease through the late 2020s before increasing through 2050 to higher levels than in 2019.
- In the Low Economic Growth case, CO2 emissions decline for most of the projection period and only begin to slowly increase after 2045.
- By 2050, CO2 emissions in the High Economic Growth case are 13% higher than in the Reference case, and those in the Low Economic Growth case are 11% lower than in the Reference case.

AEO2020 energy-related CO2 emissions increase in the industrial sector, increase as a result of natural gas consumption, but remain relatively flat in other sectors and fuel types through 2050

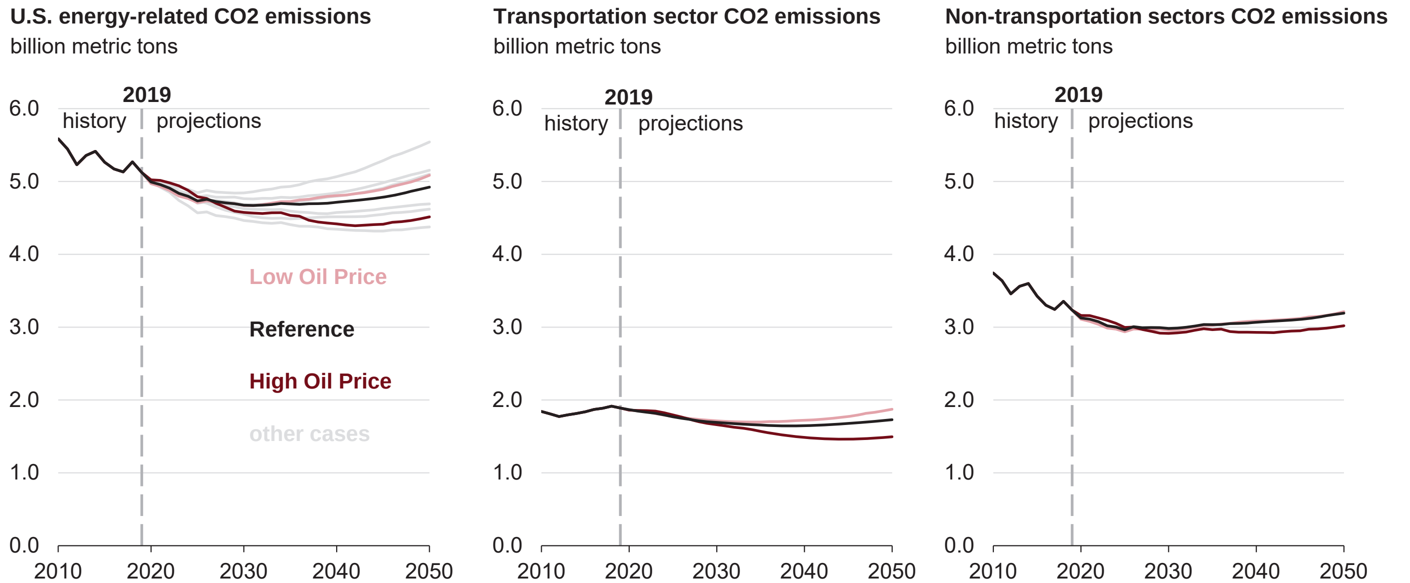
Energy-related CO2 emissions by energy sector (AEO2020 Reference case)
billion metric tons



Energy-related CO2 emissions by fuel (AEO2020 Reference case)
billion metric tons



Assumptions regarding crude oil prices affect energy-related CO2 emissions in AEO2020 —

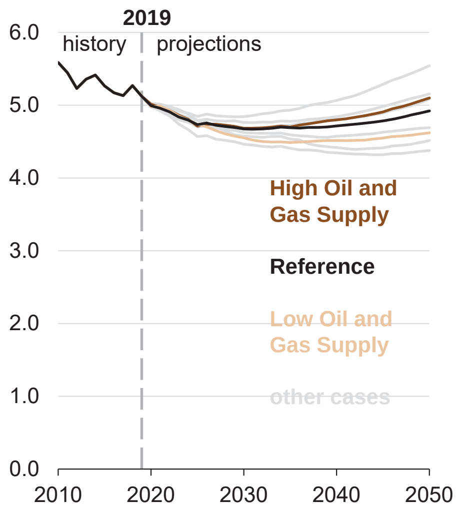


— and the oil price assumptions have the greatest effect on CO2 emissions from the transportation sector

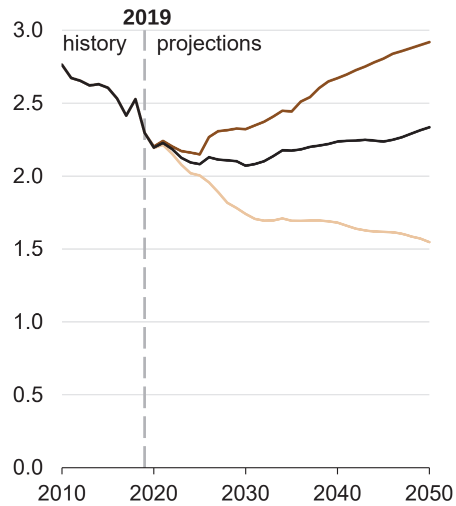
- Transportation sector emissions vary the most in the AEO2020 price cases because petroleum-related emissions dominate the transportation sector.
- In the Low Oil Price case, after an early decline, emissions increase to almost 2019 levels by 2050. Low-priced petroleum products trigger increased demand that results in greater CO2 emissions than in the Reference case.
- In the High Oil Price case, emissions decrease compared with the Reference case. Higher petroleum product prices reduce demand for petroleum products, leading to lower CO2 emissions.
- In the Low Oil Price case, transportation CO2 emissions are 1,874 million metric tons (MMmt) by 2050. In the High Oil Price case, transportation-related CO2 emissions are 1,495 MMmt.
- The industrial sector is the next most responsive sector to petroleum prices. In the Low Oil Price case, CO2 emissions from the industrial sector are 1,683 MMmt by 2050, and in the High Oil Price case, they are 1,589 MMmt.

The AEO2020 High Oil and Gas Supply and Low Oil and Gas Supply cases have different electricity generation fuel mixes than the Reference case—

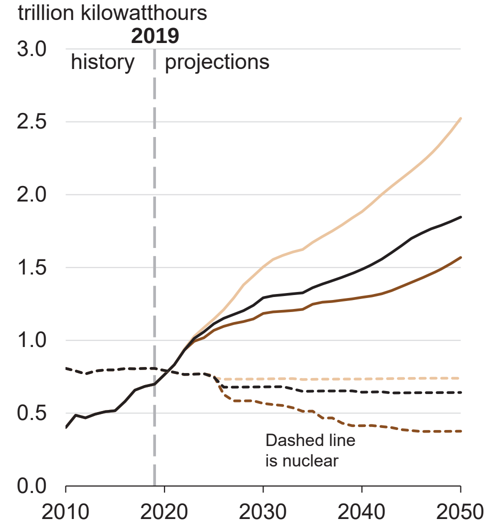
AEO2020 U.S. energy-related CO2 emissions
billion metric tons



AEO2020 fossil fuel-fired electric generation
trillion kilowatthours



AEO2020 renewables and nuclear electric generation
trillion kilowatthours



—resulting in different CO2 emissions profiles

- In the AEO2020 High Oil and Gas Supply case, energy-related CO2 emissions are higher overall compared with the Reference case, as a result of increased use of natural gas consumption, primarily in the electric power sector—and to a lesser extent, the industrial sector. The relatively low natural gas prices in this case allows natural gas to compete with renewables for new electricity generation capacity. Relatively inexpensive natural gas also accelerates nuclear retirements.

- In the Low Oil and Gas Supply case, CO2 emissions are lower overall, compared with the Reference case. Energy-related CO2 emissions decrease until about 2035 as a result of retiring coal-fired power plants, and although they increase after 2035, they remain 10% lower than 2019 levels. The relatively high natural gas prices in this case lead to greater renewables penetration and fewer nuclear retirements.

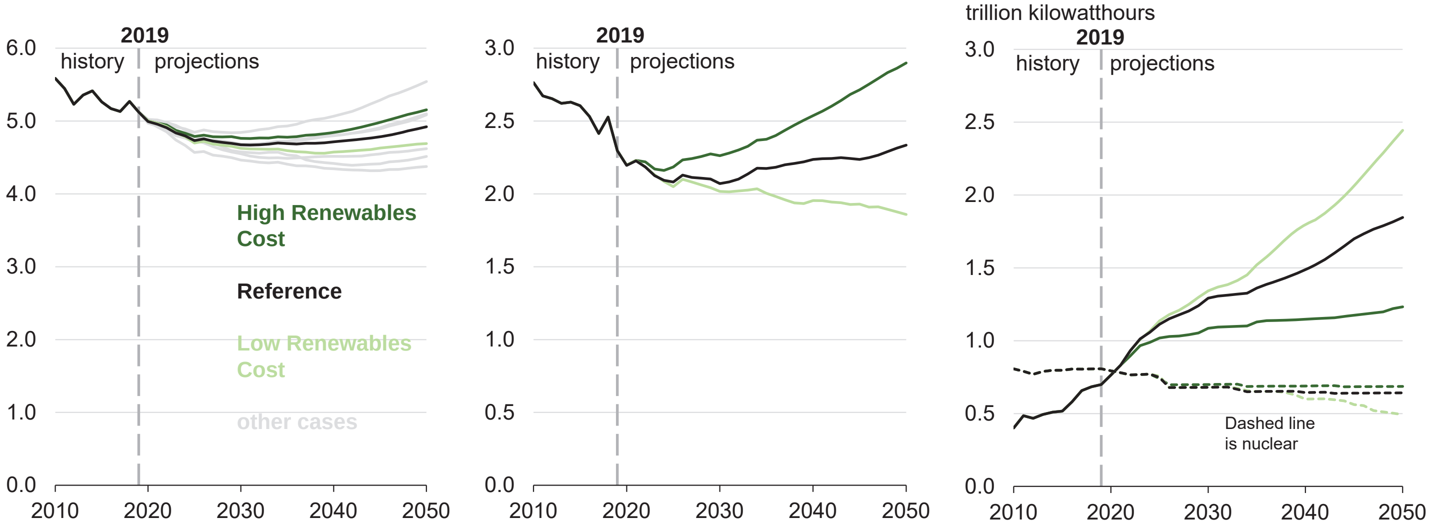
- By 2050, in the High Oil and Gas Supply case, fossil fuel-fired electric power generation is 25% higher than in the Reference case. In the Low Oil and Gas Supply case it is 34% lower than in the Reference case. The High Oil and Gas Supply case emits 5,099 MMmt CO2, and the Low Oil and Gas Supply case emits 4,620 MMmt CO2, creating a range of about 478 MMmt in CO2 emissions.

Changes in AEO2020 cost assumptions for new wind and solar projects also result in different electricity generation fuel mixes—

AEO2020 U.S. energy-related CO2 emissions
billion metric tons

AEO2020 fossil fuel-fired electric generation
trillion kilowatthours

AEO2020 renewables and nuclear electric generation
trillion kilowatthours



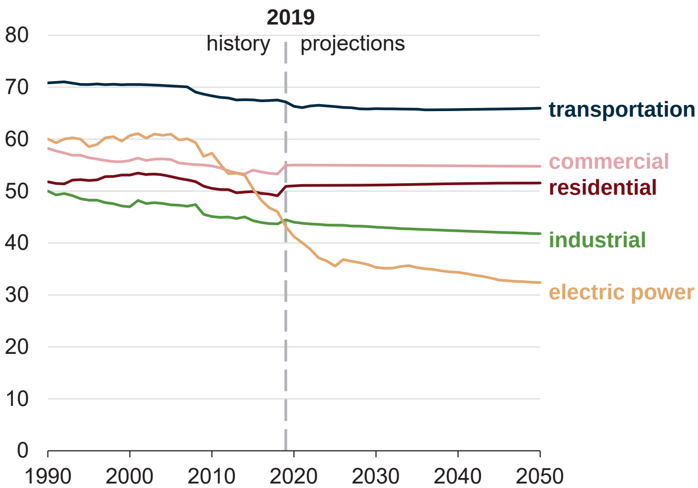
—and consequently, different energy-related carbon dioxide emission profiles

- The AEO2020 High Renewables Cost case, which assumes no further cost reductions for renewables, results in more energy-related CO_2 emissions overall compared with the Reference case throughout the projection period. Until about 2030, emissions decrease as a result of retiring coal-fired generation capacity. After 2030, less penetration of renewables, increased natural gas-fired generation, and slightly fewer nuclear retirements (compared with the Reference case) lead CO_2 emissions to return to nearly 2019 levels by 2050.

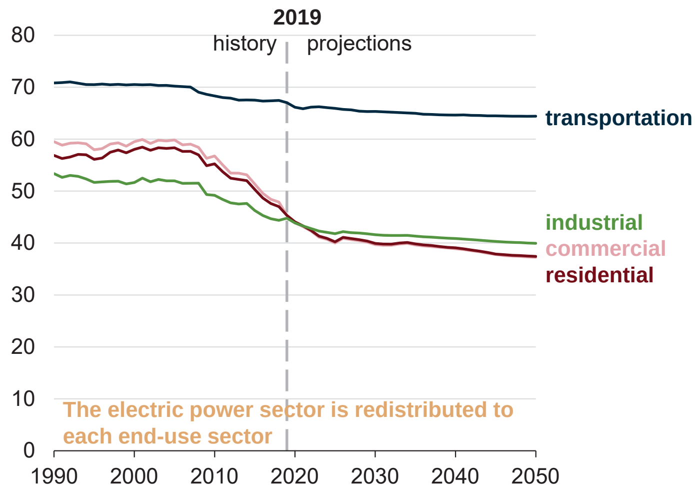
- The Low Renewables Cost case, which has sustained cost reductions for renewables through 2050, results in lower energy-related CO_2 emissions overall compared with the Reference case. Increasing electricity generation from renewables leads to decreasing emissions; after 2040, total emissions increase as a result of increased energy demand in the transportation and industrial sectors that are less dependent upon electricity. However, in 2050, emissions remain 8% lower than 2019 levels.

Across end-use sectors, carbon intensity declines with changes in the fuel mix in the AEO2020 Reference case—

Carbon intensity by energy sector (AEO2020 Reference case)
metric tons of carbon dioxide per billion British thermal units



Carbon intensity by end-use sector (AEO2020 Reference case)
metric tons of carbon dioxide per billion British thermal units



—despite overall increases in energy consumption

- Carbon intensity can vary greatly depending on the mix of fuels the end-use sectors consume. Historically, the industrial sector has had the lowest carbon intensity, as measured by CO2 emissions per British thermal unit. The transportation sector historically has had the highest carbon intensity, which continues in the projection because carbon-intensive petroleum remains the dominant fuel used in vehicles throughout the projection period.

- The generation fuel mix in the electric power sector has changed since the mid-2000s; less generation is coming from high-carbon-intensive coal, and more generation is coming from natural gas and carbon-free renewables, such as wind and solar. Because of this change, the overall carbon intensity of the electric power sector declined by 30% from the mid-2000s to 2019 and is expected to continue to decline through 2050.

- If the CO2 emissions from the electricity sector in the end-use sectors that consume electricity are accounted for, carbon intensity declines to a greater degree across those sectors for all AEO2020 cases. In the Reference case, the carbon intensities of the residential and commercial sectors show no decline when their direct carbon intensities are counted from 2019 to 2050. When the electric power sector energy is distributed to the end-use sectors, the residential and commercial sectors decline by 17% and 18%, respectively, during the projection period, and the industrial sector declines by 11%. Transportation carbon intensity declines by 4%.

References

Abbreviations

AEO = Annual Energy Outlook
b = barrel(s)
BEV = battery-electric vehicle
b/d = barrels per day
bkWh = billion kilowatthours
Btu = British thermal unit(s)
CFL = compact fluorescent lamp
CHP = combined heat and power
CO2 = carbon dioxide
CPP = Clean Power Plan
EIA = U.S. Energy Information Administration
gal = gallon(s)
GDP = gross domestic product
GW = gigawatt(s)
HGL = hydrocarbon gas liquids
ITC = investment tax credit
kWh = kilowatthour(s)
LED = light-emitting diode
LNG = liquefied natural gas
MARPOL = marine pollution, the International Convention for the Prevention of Pollution from Ships
MMBtu = million British thermal units
MMst = million short tons
NEMS = National Energy Modeling System
NGPL = natural gas plant liquids
OPEC = Organization of the Petroleum Exporting Countries
PHEV = plug-in hybrid-electric vehicle
PTC = production tax credit
PV = photovoltaic
Tcf = trillion cubic feet
ZEV = zero-emission vehicle

Graph sources

Projected values are sourced from

Projections: EIA, AEO2020 National Energy Modeling System (runs: ref2020.d112119a, highprice.d112619a, lowprice.d112619a, highmacro.d112619a, lowmacro.d112619a, highogs.d112619a, lowogs.d112619a, hirencst.d1126a, lorencst.1201a)

EIA historical data are sourced from

- *Monthly Energy Review* (and supporting databases), September 2019
- Form EIA-860M, *Preliminary Monthly Electric Generator Inventory*, July 2019

For source information for specific graphs published in this document, contact annualenergyoutlook@eia.gov.

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AEO Working Groups

https://www.eia.gov/outlooks/aeo/workinggroup/

AEO Analysis and Forecasting Experts

https://www.eia.gov/about/contact/forecasting.php#longterm

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For more information

U.S. Energy Information Administration homepage | www.eia.gov

Short-Term Energy Outlook | www.eia.gov/steo

Annual Energy Outlook | www.eia.gov/aeo

International Energy Outlook | www.eia.gov/ieo

Monthly Energy Review | www.eia.gov/mer

Today in Energy | www.eia.gov/todayinenergy

Public Version of GPP Attachment No. 3 – Appendix C

TRADE EXECUTION PROCESS OVERVIEW

1. Trade Execution Method

[redacted]

2. Trade Execution Timing

The exchange traded instruments, for the Gas Purchase Year July 1, 2020 - June 30, 2021, will be transacted sometime between the spring of 2020 and the winter heating season beginning November 1, 2020.

Volumes and timing of the transactions are subject to change based on annual discussions with Staff and the OCC.

3. Price Transparency

Natural gas derivatives are largely dependent on the natural gas futures market for underlying price determination. Options pricings are based on standardized models (Black-Scholes, etc.), which utilize common input values. Because of the common ground between models and variables, pricing between different firms varies little for generic instruments.

BLACK HILLS CORPORATION
COMPANY PROCEDURE

Procedure No.	**Revision No.**	**Page**	**of**
Corp-Risk 01-01	2	1	10

Affected Business Unit(s):	**Originating Department(s)**	
	Corporate Risk Department	
ALL	**Final Approval** ERC	**Date** 12-15-14

Subject

CREDIT RISK MANAGEMENT PROCEDURES

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PROCEDURE NAME	PROCEDURE NUMBER	
Credit Risk Management Procedures	**Corp-Risk-01-01**	**Page 2 of 10**

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Credit Risk Management Procedures	Corp-Risk-01-01	Page 7 of 10

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Credit Risk Management Procedures	Corp-Risk-01-01	Page 9 of 10

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BLACK HILLS CORPORATION
COMPANY POLICY

Policy Name: CORPORATE CREDIT POLICY	DATE ISSUED June 21, 2012	POLICY NO. CORP-RISK-01
	DATE EFFECTIVE June 21, 2012	PAGE NO. 1 of 4
POLICY NO. DATED SUPERSEDES	DEPARTMENT CRO	APPROVED SH for Sr. Mgt
	REVIEWED BY CEO, CFO and CRO	REVIEW DATE July 3, 2012

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Policy Name:	PAGE	POLICY NO.
Corporate Credit Policy	2 of 4	Corp-Risk-01

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Policy Name:	PAGE	POLICY NO.
Corporate Credit Policy	3 of 4	Corp-Risk-01

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Policy Name:	PAGE	POLICY NO.
Corporate Credit Policy	4 of 4	Corp-Risk-01

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Natural Gas Hedging Program
Black Hills Colorado Gas, Inc.

July 1, 2020 – June 30, 2023

Executive Summary

Black Hills Colorado Gas, Inc. d/b/a Black Hills Energy (successor in interest in Black Hills/Colorado Gas Utility Company, Inc. and Black Hills Gas Distribution, LLC) ("BHCG" or the "Company") is proposing the following gas hedging program for the three (3) gas purchase years[1] beginning July 1, 2020 and ending June 30, 2023:

- The hedging performance of each gas purchase year will be measured and reported. The three gas purchase years covered by this proposed program are:

Gas Purchase Year
July 1, 2020 – June 30, 2021 ("Gas Purchase Year 1")
July 1, 2021 – June 30, 2022 ("Gas Purchase Year 2")
July 1, 2022 – June 30, 2023 ("Gas Purchase Year 3")

- The Company will continue to meet with the Office of Consumer Counsel ("OCC") and the Colorado Public Utilities Commission Trial Staff ("Staff") in the spring of each year to present the hedging performance for the prior Gas Purchase Year and current market conditions as they relate to the hedging plans for the upcoming Gas Purchase Year(s). These meetings will serve as an opportunity for the Company to explain and support any changes to the targeted volumes and transaction timing discussed in this plan based on updated market conditions at the time of the meeting.

- Outside of storage, the Company's hedging program will only utilize call options as the hedging instrument and will not exceed the proposed hedging budget.

- Call options will only be transacted for forecasted winter volumes of each Gas Purchase Year sometime between the spring meeting with the OCC and Staff and the beginning of the winter heating season. Winter heating season volumes are those consumed during the time period of November – March.

- For each Gas Purchase Year shown in the table above, call option premiums will not exceed the call option budget, which will be set using:
    - a maximum <u>average</u> call option premium price of $0.45 per MMBtu; and

[1] Commission Rule 4601(q) defines a gas purchase year as "a 12-month period from July 1 through June 30."

- o [redacted] of the forecasted winter volumes in that gas purchase year's Gas Purchase Plan ("GPP").[2] The [redacted] represents the targeted hedging volumes at this time and will be used as a ceiling for budgeting purposes. Actual hedged volumes will be at or below [redacted] of the forecasted winter volumes.

- The Company's GPP will transparently show the hedging budget and hedging volumes for the upcoming winter heating season.

Proposed Hedging Instruments

Outside of storage, the Company is proposing to use call option purchases as the only financial hedging instrument for the winter volumes of Gas Purchase Years 1, 2 and 3. A call option is a contract which gives the buyer the right -but not the obligation- to purchase an underlying asset (or, in the case of financial options, to purchase a referenced index) at a specified price. The given purchase price is referred to as the "strike price." The amount the call option purchaser pays for the contractual right mentioned above is known as the "premium." As detailed in the "Hedging Budget" section below, the Company's proposed budget is not to exceed a maximum average call option premium per Gas Purchase Year of $0.45 per MMBtu hedged.

As an example, assume the Company could, in August 2020, purchase a call option for gas to be delivered in the December 2020 contract month, with a $3.50 per MMBtu strike price and a $0.45 per MMBtu call option premium price. If, in December 2020, gas prices increased to $4.50 per MMBtu, the call option purchaser (Company) will receive $1.00 on the option settlement (the excess of the actual price over the strike price). Because the initial cost of the call was $0.45, the purchaser will net $0.55 on the transaction.

If the Company purchases the same $3.50 strike price and $0.45 call option premium in August 2020 and then December 2020 gas prices drop to $2.25 per MMBtu, the Company would not exercise the call option and thus, customers would pay for the $2.25 per MMBtu gas price and the additional $0.45 per MMBtu call option premium even though it was not exercised.

Hedging Volumes

The Company is proposing to hedge up to [redacted] of each of the forecasted winter sales requirements for Gas Purchase Years 1, 2 and 3. As previously mentioned, the Company will update the volumes to be hedged in the GPP following the annual hedging meeting with Staff and the OCC, and prior to the upcoming winter heating season.

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[2] PUC Rule 4601(o) defines a Gas Purchase Plan as "a submittal that describes the utility's planned purchases of gas commodity and upstream services to be used to meet sales gas and gas transportation demand." The GPP for BHCG is filed each year on or before June 1.

Hedging Budget

The final budget will be created by taking the hedging volumes from the GPP, as discussed directly above, and multiplying these volumes by a $0.45 per MMBtu maximum average call option premium price. The $0.45 per MMBtu call option premium price represents the average premiums paid and was strictly used to set the maximum budget. While the Company's average call option premiums paid per MMBtu in aggregate could be less than $0.45 per MMBtu for a winter heating season, the Company will not exceed the $0.45 per MMBtu average premium price.

Using the [redacted] of targeted winter volumes and average aggregated $0.45 per MMBtu call option premium price, the estimated budgets for the Company at this time are shown in the table below. These volumes will be updated in the Company's GPP following the annual hedging meeting with Staff and the OCC.

Company	Forecasted Volumes to be Hedged for each Gas Purchase Year	Average Call Option Premium Price	Forecasted Hedging Budget for Each Gas Purchase Year
July 1, 2020 – June 30, 2021	[redacted] MMBtu	$0.45 per MMBtu	[redacted]
July 1, 2021 – June 30, 2022	[redacted] MMBtu	$0.45 per MMBtu	[redacted]
July 1, 2022 – June 30, 2023	[redacted] MMBtu	$0.45 per MMBtu	[redacted]

Financial Transactions

The call options for each Gas Purchase Year will be purchased after the annual hedging meeting with Staff and the OCC in the spring of each Gas Purchase Year. As shown in the table above, the total call option purchases for each Gas Purchase Year are currently targeted at [redacted] of that year's forecasted winter sales requirements (subject to the budget). The final hedged volumes will be at or below the [redacted] of forecasted winter sales requirements.

Call options for natural gas may be purchased through a broker using exchange traded futures contracts (which are traded on the New York Mercantile Exchange and the Intercontinental Exchange), or directly with counterparties through the over-the-counter market. Qualified counterparties will be financial derivative market participants that have met the Company's creditworthiness requirements. The Company shall maintain risk management trading procedures and policies to govern and oversee risk management practices and trading personnel.

Cost Recovery

The Company will recover all hedging costs at or below its final call option budget amount shown in the GPP and for each of the gas purchase years detailed in this plan through the Gas Cost Adjustment. These final budget amounts will fall within the established parameters from this plan. These final budget amounts will be included with the total forecasted commodity costs in the annual GCA filing. These forecasted hedging costs will be trued-up in the 191 deferred balance. This cost recovery methodology is consistent with the recovery of the Company's current hedging program costs stated in the Company's Tariffs.

Future Hedging Program Filing and Reporting Requirements

BHCG will file a report with the Commission no later than April 30th each year as detailed in this plan. The report will detail the past hedging activities and performance from the corresponding gas purchase year. The report will include hedged volumes, strike prices, call option premium prices, trade dates, and total settlement dollars.

The Company will continue to meet with Staff and the OCC each year in the spring to present the Company's hedging performances for the prior Gas Purchase Year and updated market conditions as they relate to the hedging plans for the upcoming Gas Purchase Year(s). These meetings will serve as an opportunity for the Company to explain and support any changes to the targeted volumes and transaction timing discussed in this plan based on updated market conditions at the time of the meeting.

Black Hills Energy
Ready

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
Forecasted Upstream Service Costs
GPP Attachment No. 4

GPP Attachment No. 4 provides detailed projections of upstream supply costs for BHCG, by month, for the July 1, 2020 – June 30, 2021 gas purchase year. Specifically, this schedule displays data applicable to each of the following:

1. BHCG's projection of all upstream services, by provider and service level;
2. BHCG's projection of pricing for each upstream service;
3. BHCG's forecasted design peak day quantity; and
4. BHCG's forecasted capacity release volumes and revenues for upstream services.

BHCG annually conducts a peak day analysis to assess the appropriate levels of service and mix of services to be secured from its upstream suppliers. This evaluation is important and provides the basis for managing upstream transportation costs while assuring that reliability is not sacrificed. Moreover, as BHCG can amend its contracts on an annual basis, we are provided with flexibility to adjust the service levels as the gas supply and/or demand environment changes over time. The upstream providers are:

1. Tallgrass Interstate Gas Transmission, LLC ("TIGT") for North/Southwest GCA region;

2. Public Service Company of Colorado ("PSCo"), for the North/Southwest GCA region;

3. Rocky Mountain Natural Gas (RMNG) for most of the capacity for the Western Slope GCA region;

4. TransColorado and NWPL for a lesser amount of capacity for the Western Slope GCA rate area (primarily, this capacity is needed to deliver gas to BHCG customers in the Nucla/Naturita area);

5. Colorado Interstate Gas ("CIG") for the Central GCA region; and

6. Red Cedar Gathering Company for the North/Southwest GCA region.

As part of its peak day analysis, BHCG derives its design peak day, or essentially an estimate of the one-day distribution system requirement on the coldest day of the year. This design peak day typically occurs during the winter season, between December and February. BHCG's most recent analysis of historical weather events indicated a peak day design condition between 67 to 82 heating degree days (- 2 to -17 degree Fahrenheit average daily temperature) depending on the area. Once the peak day design condition is derived, peak day demand requirements are calculated through a linear regression model developed from historical weather and demand data. Peak day demand requirements are adjusted to account for pipeline fuel and gas loss to arrive at the appropriate level of upstream transportation capacity.

Black Hills Energy
Ready

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
Forecasted Upstream Service Costs
GPP Attachment No. 4

Specific information is being filed with a request this information be treated as confidential, proprietary and market-sensitive, are highlighted in yellow, and is labeled as:

- Confidential Central GPP Attachment No. 4;
  - Confidential Central GPP Attachment No. 4 (Formerly Arkansas Valley GCA Rate Area);
  - Confidential Central GPP Attachment No. 4 (Formerly BHCOG GCA Rate Area);
- Confidential North/Southwest GPP Attachment No. 4;
  - Confidential North/Southwest GPP Attachment No. 4 (Formerly North Central GCA Rate Area);
  - Confidential North/Southwest GPP Attachment No. 4 (Formerly North Eastern GCA Rate Area);
  - Confidential North/Southwest GPP Attachment No. 4 (Formerly Southwestern GCA Rate Area); and
- Confidential Western Slope GPP Attachment No. 4.

BHCG treats the highlighted information contained in GPP Attachment No. 4 as confidential and requests that the Commission also treat such portions of GPP Attachment No. 4 as confidential. A public version of GPP Attachment No. 4 is also being filed.

BHCG-CO 2020- 2021 GAS PURCHASE PLAN

GPP ATTACHMENT NO. 4

FORECASTED UPSTREAM SERVICE COSTS (PUBLIC VERSIONS)

Central GPP Attachment No. 4

Central GPP Attachment No. 4 (Formerly Arkansas Valley GCA Rate Area)
Central GPP Attachment No. 4 (Formerly BHCOG GCA Rate Area)

North/Southwest GPP Attachment No. 4

North/Southwest GPP Attachment No. 4 (Formerly North Central GCA Rate Area)
North/Southwest GPP Attachment No. 4 (Formerly North Eastern GCA Rate Area)
North/Southwest GPP Attachment No. 4 (Formerly Southwestern GCA Rate Area)

Western Slope GPP Attachment No. 4

Submitted in Compliance with Commission Rule 4606(d)

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
PUBLIC VERSION 2020 - 2021 Forecasted Upstream Service Costs - Central GCA Region
Commission Rule 4606(d)
(Volume in MMBtu)

Transportation Costs	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Total
Total Transportation Costs	[redacted]												

	Jul-20 - Jun-21
Forecasted Design Peak Day Quantity	[redacted]

Central GPP Attachment No. 4
(Formerly Arkansas Valley GCA Rate Area)
Page 1 of 1

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
PUBLIC VERSION 2020 - 2021 Forecasted Upstream Service Costs - Central GCA Region (formerly Arkansas Valley GCA Rate Area)
Commission Rule 4606(d)
(Cost in Dollars)

TRANSPORTATION & OTHER		Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Total
Contract No. 33171032: TF-1, 10/1/09-12/31/38														
FT Reservation	$9.0095	$66,445	$66,445	$66,445	$66,445	$66,445	$66,445	$66,445	$66,445	$66,445	$66,445	$66,445	$66,445	$797,340
Valley Line Gas Quality Reservation	$0.4760	$3,511	$3,511	$3,511	$3,511	$3,511	$3,511	$3,511	$3,511	$3,511	$3,511	$3,511	$3,511	$42,132
FT Commodity	$0.0166	[redacted]												$20,373
Annual Charge Adjustment	$0.0013	[redacted]												$1,552
Valley Line Gas Quality Commodity	$0.0090	[redacted]												$11,046
Sub-Total		[redacted]												$872,443
Contract No. 33175032: TF-1, 4/1/16-3/31/21														
FT Reservation	$9.0095	$28,605	$28,605	$28,605	$28,605	$28,605	$28,605	$28,605	$28,605	$28,605	$28,605	$28,605	$28,605	$343,260
Valley Line Gas Quality Reservation	$0.4760	$1,511	$1,511	$1,511	$1,511	$1,511	$1,511	$1,511	$1,511	$1,511	$1,511	$1,511	$1,511	$18,132
FT Commodity	$0.0166	[redacted]												$1,372
Annual Charge Adjustment	$0.0013	[redacted]												$103
Valley Line Gas Quality Commodity	$0.0090	[redacted]												$745
Sub-Total		[redacted]												$363,612
Contract No. 31043001: NNT-1, 4/1/16-3/31/21														
NNS Reservation	$7.5696	$8,205	$8,327	$30,543	$52,753	$55,531	$55,531	$55,531	$54,365	$43,480	$31,648	$21,263	$7,070	$424,247
Valley Line Gas Quality Reservation	$0.4760	$516	$524	$1,921	$3,317	$3,492	$3,492	$3,492	$3,419	$2,734	$1,990	$1,337	$445	$26,679
NNT Commodity Withdrawal	$0.0220	[redacted]												$4,327
NNT Commodity Injection	$0.0075	[redacted]												$1,476
Annual Charge Adjustment	$0.0013	[redacted]												$248
Valley Line Gas Quality Commodity	$0.0090	[redacted]												$1,770
Sub-Total		[redacted]												$458,747
Credits														
Capacity Release		[redacted]												
Total Transportation and Other		[redacted]												

	Jul-20 - Jun-21
Forecasted Design Peak Day Quantity	[redacted]

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
PUBLIC VERSION 2020 - 2021 Forecasted Upstream Service Costs - Central GCA Region (formerly BHCOG GCA Rate Area)
Commission Rule 4606(d)
(Cost in Dollars)

TRANSPORTATION & OTHER		Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Total
Contract No. 215679: NNT-1, 5/1/02-4/30/22														
MDQ		2,764	2,808	10,287	17,769	18,704	18,704	18,704	18,312	14,646	10,662	7,163	2,382	
NNT-1 Reservation	$7.5696	$ 20,922	$ 21,240	$ 77,868	$ 134,504	$ 141,582	$ 141,582	$ 141,582	$ 138,615	$ 110,864	$ 80,707	$ 54,221	$ 18,031	
Gas Quality Reservation Quantity		2,457	2,494	9,145	15,797	16,628	16,628	16,628	16,279	13,020	9,478	6,368	2,118	
Gas Quality Reservation	$0.4760	$ 1,170	$ 1,187	$ 4,353	$ 7,519	$ 7,915	$ 7,915	$ 7,915	$ 7,749	$ 6,198	$ 4,512	$ 3,031	$ 1,008	
Subtotal NNT-1 Fixed		$ 22,092	$ 22,427	$ 82,221	$ 142,023	$ 149,497	$ 149,497	$ 149,497	$ 146,364	$ 117,062	$ 85,219	$ 57,252	$ 19,039	$1,142,190
NNT Commodity Withdrawal	$0.0220	[redacted]												
NNT Commodity Injection	$0.0075	[redacted]												
Annual Charge Adjustment	$0.0013	[redacted]												
Valley Line Gas Quality Commodity	$0.0090	[redacted]												
Subtotal NNT-1 Variable		[redacted]												$25,087
Total NNT-1		$ 23,651	$ 23,874	$ 83,668	$ 143,562	$ 150,307	$ 151,722	$ 151,722	$ 148,184	$ 122,118	$ 89,264	$ 58,699	$ 20,486	$ 1,167,277
Contract No. 215682: TF-1, 1/1/18-10/31/21														
MDQ	3,045													
TF-1 Reservation	$9.0095	$ 27,434	$ 27,434	$ 27,434	$ 27,434	$ 27,434	$ 27,434	$ 27,434	$ 27,434	$ 27,434	$ 27,434	$ 27,434	$ 27,434	
Gas Quality Reservation	$0.4760	$ 1,449	$ 1,449	$ 1,449	$ 1,449	$ 1,449	$ 1,449	$ 1,449	$ 1,449	$ 1,449	$ 1,449	$ 1,449	$ 1,449	
Total TF-1		$ 28,883	$ 28,883	$ 28,883	$ 28,883	$ 28,883	$ 28,883	$ 28,883	$ 28,883	$ 28,883	$ 28,883	$ 28,883	$ 28,883	$ 346,596
Contract No. 215707: TF-1, 5/1/02-6/30/26														
MDQ	4,247													
TF-1 Reservation	$9.0095	$ 38,263	$ 38,263	$ 38,263	$ 38,263	$ 38,263	$ 38,263	$ 38,263	$ 38,263	$ 38,263	$ 38,263	$ 38,263	$ 38,263	
Gas Quality Reservation	$0.4760	$ -	$ -	$ -	$ 2,022	$ 2,022	$ 2,022	$ 2,022	$ 2,022	$ 2,022	$ 2,022	$ -	$ -	
Total TF-1		$ 38,263	$ 38,263	$ 38,263	$ 40,285	$ 40,285	$ 40,285	$ 40,285	$ 40,285	$ 40,285	$ 40,285	$ 38,263	$ 38,263	$ 473,310
Contract No. 215681: TF-1, 1/1/18-10/31/21														
MDQ	10,000													
TF-1 Reservation	$9.0095	$ 90,095	$ 90,095	$ 90,095	$ 90,095	$ 90,095	$ 90,095	$ 90,095	$ 90,095	$ 90,095	$ 90,095	$ 90,095	$ 90,095	
Gas Quality Reservation	$0.4760	$ 4,760	$ 4,760	$ 4,760	$ 4,760	$ 4,760	$ 4,760	$ 4,760	$ 4,760	$ 4,760	$ 4,760	$ 4,760	$ 4,760	
Total TF-1		$ 94,855	$ 94,855	$ 94,855	$ 94,855	$ 94,855	$ 94,855	$ 94,855	$ 94,855	$ 94,855	$ 94,855	$ 94,855	$ 94,855	$ 1,138,260
Contract No. 215685: TF-1, 11/1/02-10/31/21														
MDQ	10,000													
TF-1 Reservation	$9.0095	$ 90,095	$ 90,095	$ 90,095	$ 90,095	$ 90,095	$ 90,095	$ 90,095	$ 90,095	$ 90,095	$ 90,095	$ 90,095	$ 90,095	
Gas Quality Reservation	$0.4760	$ -	$ -	$ -	$ 4,760	$ 4,760	$ 4,760	$ 4,760	$ 4,760	$ 4,760	$ 4,760	$ -	$ -	
Total TF-1		$ 90,095	$ 90,095	$ 90,095	$ 94,855	$ 94,855	$ 94,855	$ 94,855	$ 94,855	$ 94,855	$ 94,855	$ 90,095	$ 90,095	$1,114,460
Contract No. 215695: TF-1, 11/1/02-10/31/21														
MDQ	22,898													
TF-1 Reservation	$9.0095	$ 206,300	$ 206,300	$ 206,300	$ 206,300	$ 206,300	$ 206,300	$ 206,300	$ 206,300	$ 206,300	$ 206,300	$ 206,300	$ 206,300	
Gas Quality Reservation Quantity		20,753	20,753	20,753	20,753	20,753	19,424	19,424	19,424	19,424	19,424	19,424	19,424	
Gas Quality Reservation	$0.4760	$ 9,878	$ 9,878	$ 9,878	$ 9,878	$ 9,878	$ 9,246	$ 9,246	$ 9,246	$ 9,246	$ 9,246	$ 9,246	$ 9,246	
Total TF-1		$ 216,178	$ 216,178	$ 216,178	$ 216,178	$ 216,178	$ 215,546	$ 215,546	$ 215,546	$ 215,546	$ 215,546	$ 215,546	$ 215,546	$ 2,589,712
Contract No. 215684: TF-1, 11/1/06-10/31/21														
MDQ		-	-	-	-	7,000	7,000	7,000	7,000	7,000	-	-	-	
TF-1 Reservation Rate	$9.0095	$ -	$ -	$ -	$ -	$ 63,067	$ 63,067	$ 63,067	$ 63,067	$ 63,067	$ -	$ -	$ -	
Gas Quality Reservation	$0.4760	$ -	$ -	$ -	$ -	$ 3,332	$ 3,332	$ 3,332	$ 3,332	$ 3,332	$ -	$ -	$ -	
Total TF-1		$ -	$ -	$ -	$ -	$ 66,399	$ 66,399	$ 66,399	$ 66,399	$ 66,399	$ -	$ -	$ -	$ 331,995

Central GPP Attachment No. 4
(Formerly BHCOG GCA Rate Area)
Page 2 of 2

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
PUBLIC VERSION 2020 - 2021 Forecasted Upstream Service Costs - Central GCA Region (formerly BHCOG GCA Rate Area)
Commission Rule 4606(d)
(Cost in Dollars)

TRANSPORTATION & OTHER		**Jul-20**	**Aug-20**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Total**
Contract No. 215686: TF-1, 8/1/08-10/31/21														
MDQ	47,000													
TF-1 Reservation Rate	$9.0095	$ 423,447	$ 423,447	$ 423,447	$ 423,447	$ 423,447	$ 423,447	$ 423,447	$ 423,447	$ 423,447	$ 423,447	$ 423,447	$ 423,447	$ 5,081,364
Contract No. 215680: TF-1, 11/1/11-10/31/26														
MDQ	50,000													
Gas Quality Reservation	$3.5000	$ 175,000	$ 175,000	$ 175,000	$ 175,000	$ 175,000	$ 175,000	$ 175,000	$ 175,000	$ 175,000	$ 175,000	$ 175,000	$ 175,000	
TF-1 Reservation Quantity	50,000													
TF-1 Reservation	$0.7604	$ 38,020	$ 38,020	$ 38,020	$ 38,020	$ 38,020	$ 38,020	$ 38,020	$ 38,020	$ 38,020	$ 38,020	$ 38,020	$ 38,020	
Total TF-1		$ 213,020	$ 213,020	$ 213,020	$ 213,020	$ 213,020	$ 213,020	$ 213,020	$ 213,020	$ 213,020	$ 213,020	$ 213,020	$ 213,020	$ 2,556,240
Purchase Volumes		[redacted]												
FT-1 Commodity	$0.0166													
Annual Charge Adjustment	$0.0013													
Valley Line Gas Quality Commodity	$0.0090													
Total TF-1 Variable Transportation														$ 263,602
Total MDQ		149,954	149,996	157,477	164,959	172,894	172,894	172,894	172,502	168,636	157,852	154,353	149,572	
Total Reservation Costs		$ 1,139,786	$ 1,138,856	$ 1,199,990	$ 1,275,485	$ 1,357,024	$ 1,367,535	$ 1,367,831	$ 1,358,858	$ 1,324,807	$ 1,217,732	$ 1,179,240	$ 1,135,672	$ 15,062,816
Total Fixed Upstream Costs		$ 1,126,833	$ 1,127,168	$ 1,186,962	$ 1,253,546	$ 1,327,419	$ 1,326,787	$ 1,326,787	$ 1,323,654	$ 1,294,352	$ 1,196,110	$ 1,161,361	$ 1,123,148	$ 14,774,127
Total Variable Upstream Costs		[redacted]												$ 288,689
Total Upstream Costs		$ 1,139,786	$ 1,138,856	$ 1,199,990	$ 1,275,485	$ 1,357,024	$ 1,367,535	$ 1,367,831	$ 1,358,858	$ 1,324,807	$ 1,217,732	$ 1,179,240	$ 1,135,672	$ 15,062,816
Capacity Release														
Forecasted Dth		[redacted]												
Total Dollars														

		Jul-20 - Jun-21
Forecasted Design Peak Day Quantity		[redacted]

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
PUBLIC VERSION 2020 - 2021 Forecasted Upstream Service Costs - North/Southwest GCA Region
Commission Rule 4606(d)
(Volume in MMBtu)

Transportation Costs	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Total
Total Transportation Costs	[redacted]												

	Jul-20 - Jun-21
Forecasted Design Peak Day Quantity	[redacted]

North/Southwest GPP Attachment No. 4
(Formerly North Central GCA Rate Area)
Page 1 of 1

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
PUBLIC VERSION 2020 - 2021 Forecasted Upstream Service Costs - North/Southwest GCA Region (formerly North Central GCA Rate Area)
Commission Rule 4606(d)
(Volume in MMBtu)

Transportation Costs		Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Total
PSCO FT Service														
FT Reservation	$8.73	$197,411	$197,411	$197,411	$197,411	$197,411	$197,411	$197,411	$197,411	$197,411	$197,411	$197,411	$197,411	$2,368,932
FT Commodity	$0.2302	[redacted]												$401,167
Gas Cost Adjustment	$0.0420													$73,192
Facilities Charge (5 Facilities)	$125.15	$626	$626	$626	$626	$626	$626	$626	$626	$626	$626	$626	$626	$7,512
Backup Firm Supply Charge	$1.7280	$864	$864	$864	$864	$864	$864	$864	$864	$864	$864	$864	$864	$10,368
GRSA	0.00%	[redacted]												$0
Pipe System Integrity Adjustment	$0.46011													$801,825
Total Transportation Costs		[redacted]												**$3,662,996**

	Jul-20 - Jun-21
Forecasted Design Peak Day Quantity	[redacted]

North/Southwest GPP Attachment No. 4
(Formerly North Eastern GCA Rate Area)
Page 1 of 1

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
PUBLIC VERSION 2020 - 2021 Forecasted Upstream Service Costs - North/Southwest GCA Region (formerly North Eastern GCA Rate Area)
Commission Rule 4606(d)
(Cost in Dollars)

TRANSPORTATION & OTHER		Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Total
TIGT Monthly Transportation Demand Charges		$70,392	$70,392	$70,392	$70,392	$70,392	$70,392	$70,392	$70,392	$70,392	$70,392	$70,392	$70,392	$844,704
FT Capacity Volume	7,544													
FT Reservation Rate	$9.3309													
TIGT Transportation Commodity Charges														
Commodity	$0.0057	[redacted]												$3,048
Annual Charge Adjustment	$0.0013													$672
Electric Power Cost Reimbursement	$0.0162													$13,838
TIGT NNS Monthly Demand Charges		$48,704	$48,704	$48,704	$48,704	$48,704	$48,704	$48,704	$48,704	$48,704	$48,704	$48,704	$48,704	$584,448
NNS Capacity Volume	3,636													
NNS Reservation Rate	$13.3949													
NNS Commodity	$0.0057	[redacted]												$1,493
Total TIGT Charges														**$1,448,203**
CIG Storage Reservation	$7.5696	$23	$23	$91	$159	$167	$167	$167	$167	$129	$98	$61	$23	$1,275
CIG FT Reservation	$9.0095	$1,081	$1,081	$1,081	$1,081	$1,081	$1,081	$1,081	$1,081	$1,081	$1,081	$1,081	$1,081	$12,972
CIG Commodity	$0.0166	[redacted]												$179
Annual Charge Adjustment	$0.0013													$12
Total CIG Charges														**$14,438**
Non-Commodity P802 Charges														
Total Loss/(Gain) Amounts on P802 Sale		$27,658	$27,658	$27,658	$27,658	$27,658	$27,658	$27,658	$27,658	$27,658	$27,658	$27,658	$27,658	$331,896
Credits														
Colorado TRA Surcharge		($2,601)	($1,725)	($1,853)	($1,824)	($1,636)	($2,227)	($2,119)	($1,906)	($1,906)	($1,659)	($1,592)	($1,762)	($22,810)
Total Transport / Other Costs		**$146,425**	**$147,337**	**$147,285**	**$147,690**	**$148,056**	**$148,018**	**$148,172**	**$148,058**	**$147,522**	**$148,029**	**$147,795**	**$147,340**	**$1,771,727**

	Jul-20 - Jun-21
Forecasted Design Peak Day Quantity	[redacted]

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
PUBLIC VERSION 2020 - 2021 Forecasted Upstream Service Costs - North/Southwest GCA Region (formerly Southwestern GCA Rate Area)
Commission Rule 4606(d)
(Volume in MMBtu)

Transportation Costs		Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	**Total**
FT-1 Contract No. 116388B: 11-01-2012 - 09-30-2020	3,154													
FT Reservation ($)	$8.73	$27,534	$27,534	$27,534	$27,534	$27,534	$27,534	$27,534	$27,534	$27,534	$27,534	$27,534	$27,534	$330,408
FT Commodity	$0.2302	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$34,081
Gas Cost Adjustment	$0.0420	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$6,217
Facilities Charge (3 Facilities)	$125.15	$375	$375	$375	$375	$375	$375	$375	$375	$375	$375	$375	$375	$4,500
GRSA	0.00%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$0
Pipe System Integrity Adjustment	$0.46011	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$68,118
Total PSCo Transportation Costs		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$443,324
FT-1 Contract No. 116388: 11-01-2018 - 03-31-2025	4,750													
FT Reservation ($)	$8.73	$41,468	$41,468	$41,468	$41,468	$41,468	$41,468	$41,468	$41,468	$41,468	$41,468	$41,468	$41,468	$497,616
FT Commodity	$0.2302	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$104,569
Gas Cost Adjustment	$0.0420	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$19,078
Facilities Charge (3 Facilities)	$125.15	$375	$375	$375	$375	$375	$375	$375	$375	$375	$375	$375	$375	$4,500
Backup Firm Supply Charge (400 MMBtu)	$1.8080	$723	$723	$723	$723	$723	$723	$723	$723	$723	$723	$723	$723	$8,676
GRSA	0.00%	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$0
Pipe System Integrity Adjustment	$0.46011	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$209,005
Total PSCo Transportation Costs		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$843,444
FT-1 Contract No. 201SGD: 11-01-2018 - 03-31-2025														
Compression Fee	$5.3360	$23,212	$23,212	$23,212	$23,212	$23,212	$23,212	$23,212	$23,212	$23,212	$23,212	$23,212	$23,212	$278,544
Gathering Fee	$0.1172	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$51,788
Total Red Cedar Costs		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$330,332
Total Transportation Costs		$105,408	$107,162	$108,079	$127,803	$148,472	$174,744	$178,863	$162,405	$151,014	$128,376	$117,207	$107,567	$1,617,100

	Jul-20 - Jun-21
Forecasted Design Peak Day Quantity	[redacted]

Black Hills Colorado Gas, Inc.
d/b/a Black Hills Energy
PUBLIC VERSION 2020 - 2021 Forecasted Upstream Service Costs - Western Slope GCA Region
Commission Rule 4606(d)
(Cost in Dollars)

Western Slope GPP Attachment No. 4
Page 1 of 1

	MDQ	Rate	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Total
RMNG															
Commodity Volume			[redacted]												8,892,334
FT Reservation (April - September)	102,647	$10.2201	$1,049,063	$1,049,063	$1,049,063	$0	$0	$0	$0	$0	$0	$1,049,063	$1,049,063	$1,049,063	$6,294,378
FT Reservation (October - March)	102,647	$25.7945	$0	$0	$0	$2,647,728	$2,647,728	$2,647,728	$2,647,728	$2,647,728	$2,647,728	$0	$0	$0	$15,886,368
FT Commodity Cost		$0.0307	[redacted]												$272,993
NNS Reservation (April - September)	10,966	$4.7679	$52,285	$52,285	$52,285	$0	$0	$0	$0	$0	$0	$52,285	$52,285	$52,285	$313,710
NNS Reservation (October - March)		$17.3507	$0	$0	$0	$190,268	$190,268	$190,268	$190,268	$190,268	$190,268	$0	$0	$0	$1,141,608
Total Cost			[redacted]												**$23,909,057**
TransColorado to Kannah Cr/Whitewater															
Commodity Volume			[redacted]												34,262
FT Reservation	550	$9.3194	$5,126	$5,126	$5,126	$5,126	$5,126	$5,126	$5,126	$5,126	$5,126	$5,126	$5,126	$5,126	$61,512
FT Commodity		$0.0014	[redacted]												$48
ACA Cost		$0.00126	[redacted]												$43
Total Cost			[redacted]												**$61,603**
TransColorado to Olathe															
Commodity Volume			[redacted]												1,739,551
FT Reservation	26,650	$6.0833	$0	$0	$0	$0	$162,120	$162,120	$162,120	$162,120	$162,120	$0	$0	$0	$810,600
FT Commodity		$0.0014	[redacted]												$2,283
ACA Cost		$0.00126	[redacted]												$2,199
Total Cost			[redacted]												**$850,153**
NWPL FT to Nucla/Naturita															
Commodity Volume			[redacted]												45,407
FT Volumetric (Small Customer Minimum)	0	$0.69427	[redacted]												$31,524
Total Cost			[redacted]												**$31,524**
Colorado Interstate Gas															
Commodity Volume			[redacted]												4,730,283
FT Reservation	37,800	$4.5630	$172,481	$172,481	$172,481	$172,481	$172,481	$172,481	$172,481	$172,481	$172,481	$172,481	$172,481	$172,481	$2,069,772
Commodity		$0.0166	[redacted]												$78,522
ACA Cost		$0.00126	[redacted]												$5,981
Total Cost			[redacted]												**$2,154,275**
Credits															
Capacity Release			[redacted]												
Total Transporation Cost			[redacted]												

	Jul-20 - Jun-21
Forecasted Design Peak Day Quantity	[redacted]