COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

DUKE ENERGY KENTUCKY, INC.'S	)	
INTEGRATED RESOURCE PLAN	)	Case No. 2018-00195
	)	

PETITION OF DUKE ENERGY KENTUCKY, INC. FOR CONFIDENTIAL TREATMENT OF CERTAIN RESPONSES TO COMMISSION STAFF'S FIRST REQUEST FOR INFORMATION AND TO THE KENTUCKY ATTORNEY GENERAL'S OFFICE'S FIRST REQUEST FOR INFORMATION

Duke Energy Kentucky, Inc. (Duke Energy Kentucky or Company), pursuant to 807 KAR 5:001, Section 13, respectfully requests the Kentucky Public Service Commission (Commission) to classify and protect certain information provided by the Company in its Responses to Commission Staff's (Staff) Second Requests for Information issued on March 27, 2019. Specifically, the Company requests confidential treatment for responses to Staff's Information Request Nos. 9 and 10. The information that Duke Energy Kentucky seeks confidential treatment on generally includes third party owned and licensed modeling tools.

In support of this Petition, Duke Energy Kentucky states:

1. The Kentucky Open Records Act exempts from disclosure certain commercial information. KRS 61.878 (1)(c). To qualify for this exemption and, therefore, maintain the confidentiality of the information, a party must establish that disclosure of the commercial information would permit an unfair advantage to competitors of that party. Public disclosure of the information identified herein would, in fact, prompt such a result for the reasons set forth below.

2. Duke Energy Kentucky requests confidential protections for certain third-party data contained in the attachment responses to Staff's Information Request Nos. 9 and 10. These attachments contain certain confidential and proprietary data consisting of confidential information belonging to third parties who take reasonable steps to protect their confidential information, such as only releasing such information subject to confidentiality agreements and subscription-based usage restrictions. Duke Energy Kentucky used forecasts of various commodities and inputs such as power market data and fuel price forecasts (coal prices and gas prices) developed by independent third parties including, Moody's, Burns and McDonnel, and Navigant. Moody's provided proprietary economic data that was used in Duke Energy Kentucky's forecasts as provided in the Attachment response to STAFF-DR-02-009. Burns and McDonnel and Navigant provided data that was used in forecasting the technology included the Attachment contained in STAFF-DR-02-010. The forecast factors and associated technology costs were developed by Burns and McDonnell utilizing an AEO forecast tool along with their own proprietary data. In the case of the renewable technology information, Duke Energy Kentucky used a proprietary cost forecast from Navigant for the first 10 years and then utilized the forecast factors to extrapolate the Navigant cost forecast for the remaining 5 years.

Duke Energy Kentucky is contractually bound to maintain such information confidential. Moreover, this information is deserving of protection to protect Duke Energy Kentucky's customers. Duke Energy Kentucky relies upon information provided by vendors to perform its own analytics. Producing such information on its own would be far more expensive for the Company, and in turn, costly for customers. If Duke Energy Kentucky is unable to maintain confidentiality of information provided by these vendors, such vendors may no longer be willing to provide this information to Duke Energy Kentucky. Competitors of these vendors would have access to the proprietary modeling data and outputs and would place them at a competitive disadvantage simply because they entered into a contract with Duke Energy Kentucky. This would likely place a chilling effect on future vendors from wanting to provide information to Duke Energy Kentucky if the Company is unable to protect such information from public disclosure.

4. Duke Energy Kentucky does not object to limited disclosure of the confidential information described herein, pursuant to an acceptable protective agreement, with the Attorney General or other intervenors with a legitimate interest in reviewing the same for the purpose of participating in this case.

5. This information was, and remains, integral to Duke Energy Kentucky's effective execution of business decisions. And such information is generally regarded as confidential or proprietary. Indeed, as the Kentucky Supreme Court has found, "information concerning the inner workings of a corporation is 'generally accepted as confidential or proprietary.'" *Hoy v. Kentucky Industrial Revitalization Authority*, Ky., 904 S.W.2d 766, 768 (Ky. 1995).

6. In accordance with the provisions of 807 KAR 5:001, Section 13(3), the Company is filing one copy of the Confidential Information separately under seal, and one copy without the confidential information included.

7. Duke Energy Kentucky respectfully requests that the Confidential Information, be withheld from public disclosure for a period of ten years. This will assure that the Confidential Information – if disclosed after that time – will no longer be

commercially sensitive so as to likely impair the interests of the Company or its customers if publicly disclosed.

8. To the extent the Confidential information becomes generally available to the public, whether through filings required by other agencies or otherwise, Duke Energy Kentucky will notify the Commission and have its confidential status removed pursuant to 807 KAR 5:001 Section 13(10)(a).

WHEREFORE, Duke Energy Kentucky, Inc. respectfully requests the Commission classify and protect as confidential the specific information described herein.

Respectfully submitted,

DUKE ENERGY KENTUCKY, INC.

Rocco O. D'Ascenzo (92796)
Deputy General Counsel
Duke Energy Business Services LLC
139 East Fourth Street, 1303 Main
Cincinnati, Ohio 45201-0960
Phone: (513) 287-4320
Fax: (513) 287-4385
E-mail: rocco.d'ascenzo@duke-energy.com
Counsel for Duke Energy Kentucky, Inc.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing filing was served on the following via U.S. Mail, first class, postage prepaid, this 11th day of April 2019:

Rebecca W. Goodman
The Office of the Attorney General
Utility Intervention and Rate Division
700 Capital Avenue, Suite 20
Frankfort, Kentucky 40601

Rocco D'Ascenzo

VERIFICATION

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, Andrew Ritch, Wholesale Renewable Manager IV, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Andrew Ritch., Affiant

Subscribed and sworn to before me by Andrew Ritch on this 1st day of April, 2019.

NOTARY PUBLIC

My Commission Expires: No Expiration

NOTARIAL SEAL
STATE OF OHIO

ROCCO O. D'ASCENZO
ATTORNEY AT LAW
Notary Public, State of Ohio
My Commission Has No Expiration
Section 147.03 R.C.

VERIFICATION

STATE OF OHIO	)	
	)	**SS:**
COUNTY OF HAMILTON	)	

The undersigned, Michael J. Pahutski, Regional Director of Regional Large Account Management, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests for which he is identified as a witness, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Michael J. Pahutski, Affiant

Subscribed and sworn to before me by Michael J. Pahutski on this 1st day of April, 2019.

NOTARY PUBLIC

My Commission Expires: July 8, 2022

NOTARY PUBLIC
STATE OF OHIO

E. MINNA ROLFES-ADKINS
Notary Public, State of Ohio
My Commission Expires
July 8, 2022

VERIFICATION

STATE OF OHIO	)	
	)	**SS:**
COUNTY OF HAMILTON	)	

The undersigned, Rhonda Whitaker, VP Community Relations, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of her knowledge, information and belief.

Rhonda Whitaker
Rhonda Whitaker, Affiant

Subscribed and sworn to before me by Rhonda Whitaker on this 8th day of April, 2019.

Dina O. Riemann
NOTARY PUBLIC

My Commission Expires:

DINA O. RIEMANN, Attorney at Law
Notary Public, State of Ohio
My Commission Has No Expiration Date.
Section 147.03

VERIFICATION

STATE OF NORTH CAROLINA	)	
	)	**SS:**
COUNTY OF MECKLENBURG	)	

The undersigned, John A. Verderame, Managing Director, Power Trading and Dispatch, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

[signature]

John A. Verderame Affiant

Subscribed and sworn to before me by John A. Verderame on this 1 day of April, 2019.

Mary B Vicknair

NOTARY PUBLIC

My Commission Expires:

MARY B VICKNAIR
NOTARY PUBLIC
Davie County
North Carolina
My Commission Expires Sept. 21, 2022

<u>**VERIFICATION**</u>

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, Tammy Jett, Principal Environmental Specialist, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of her knowledge, information and belief.

Tammy Jett

Tammy Jett, Affiant

Subscribed and sworn to before me by Tammy Jett on this 1st day of April, 2019.

Ruth M. Loccisano

NOTARY PUBLIC

My Commission Expires: 06-18-2022

NOTARIAL SEAL
STATE OF OHIO

RUTH M. LOCCISANO
Notary Public, State of Ohio
My Commission Expires 06-18-2022

VERIFICATION

STATE OF NORTH CAROLINA	)	
	)	**SS:**
COUNTY OF MECKLENBURG	)	

The undersigned, Benjamin Passty, Lead Load Forecasting Analyst, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Benjamin W B Passty
Benjamin Passty, Affiant

Subscribed and sworn to before me by Benjamin Passty on this 3 day of April, 2019.

KATIE JAMIESON
Notary Public, North Carolina
Gaston County
My Commission Expires

Katie Jamieson
NOTARY PUBLIC

My Commission Expires: June 14, 2021

VERIFICATION

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, James Ziolkowski, Director of Rates & Regulatory Planning, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

James Ziolkowski, Affiant

Subscribed and sworn to before me by James Ziolkowski on this 4TH day of APRIL, 2019.

ADELE M. FRISCH
Notary Public, State of Ohio
My Commission Expires 01-05-2024

Adele M. Frisch
NOTARY PUBLIC

My Commission Expires: 1/5/2024

VERIFICATION

STATE OF NORTH CAROLINA	)	
	)	**SS:**
COUNTY OF MECKLENBURG	)	

The undersigned, John L. Sullivan, III, Director, Corporate Finance and Assistant Treasurer, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

John L. Sullivan III

John L. Sullivan, III Affiant

Subscribed and sworn to before me by John L. Sullivan, III on this 2 day of April, 2019.

HEATHER PAIGE BLUM NOTARY PUBLIC MECKLENBURG COUNTY, N.C.

Heather Paige Blum

NOTARY PUBLIC

My Commission Expires: 1/9/2023

VERIFICATION

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, Heather Quinley, Director MW Energy Affairs & Stakeholder Eng., being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of her knowledge, information and belief.

Heather Quinley, Affiant

Subscribed and sworn to before me by Heather Quinley on this 9th day of April, 2019.

NOTARY PUBLIC

My Commission Expires: July 8, 2022

E. MINNA ROLFES-ADKINS
Notary Public, State of Ohio
My Commission Expires
July 8, 2022

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, Scott Park, Director IRP & Analytics-Midwest, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Scott Park, Affiant

Subscribed and sworn to before me by Scott Park on this 10th day of April, 2019.

NOTARY PUBLIC

My Commission Expires: Oct. 20, 2023

VERIFICATION

STATE OF NORTH CAROLINA	)	
	)	**SS:**
COUNTY OF MECKLENBURG	)	

The undersigned, John Swez, Director General Dispatch & Operations of Power Trading & Dispatch, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests are true and correct to the best of his knowledge, information and belief.

John Swez, Affiant

Subscribed and sworn to before me by John Swez on this 1 day of April, 2019.

Mary B Vicknair

NOTARY PUBLIC

My Commission Expires:

MARY B VICKNAIR
NOTARY PUBLIC
Davie County
North Carolina
My Commission Expires Sept. 21, 2022

VERIFICATION

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, Zachary Kuznar, Manager Director CHP Microgrid & Energy Storage Development, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Zachary Kuznar, Affiant

Subscribed and sworn to before me by Zachary Kuznar, on this 2nd day of April, 2019.

NOTARY PUBLIC

My Commission Expires: July 8, 2022

NOTARY PUBLIC STATE OF OHIO

E. MINNA ROLFES-ADKINS
Notary Public, State of Ohio
My Commission Expires
July 8, 2022

VERIFICATION

STATE OF NORTH CAROLINA	)	
	)	**SS:**
COUNTY OF MECKLENBURG	)	

The undersigned, Andrew R. James, Strategic Planning Manager, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony and that it is true and correct to the best of his knowledge, information and belief.

Andrew R. James, Affiant

Subscribed and sworn to before me by Andrew R. James on this 2 day of April, 2019.

KATIE JAMIESON
Notary Public, North Carolina
Gaston County
My Commission Expires

Katie Jamieson
NOTARY PUBLIC

My Commission Expires: June 14, 2021

VERIFICATION

STATE OF NORTH CAROLINA)
) **SS:**
COUNTY OF MECKLENBURG)

The undersigned, Tim Duff, GM Customer Reg. Strategy & Analytics, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Tim Duff, Affiant

Subscribed and sworn to before me by Tim Duff on this 28 day of March, 2019.

KATIE JAMIESON
Notary Public, North Carolina
Gaston County
My Commission Expires

Katie Jamieson
NOTARY PUBLIC

My Commission Expires: June 14, 2021

VERIFICATION

STATE OF OHIO)
) SS:
COUNTY OF HAMILTON)

The undersigned, Gregory Cecil, Project Director, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

Gregory Cecil Affiant

Subscribed and sworn to before me by Gregory Cecil on this 11TH day of APRIL, 2019.

NOTARIAL SEAL STATE OF OHIO

ADELE M. FRISCH
Notary Public, State of Ohio
My Commission Expires 01-05-2024

Adele M. Frisch
NOTARY PUBLIC

My Commission Expires: 1/5/2024

<u>**VERIFICATION**</u>

STATE OF OHIO)
) **SS:**
COUNTY OF HAMILTON)

The undersigned, J. Michael Geers, Manager Environmental Services, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of his knowledge, information and belief.

J. Michael Geers
J. Michael Geers, Affiant

Subscribed and sworn to before me by Michael Geers, on this 15th day of APRIL, 2019.

Ruth M. Loccisano
NOTARY PUBLIC

My Commission Expires: 06-18-2022

NOTARIAL SEAL STATE OF OHIO

RUTH M. LOCCISANO
Notary Public, State of Ohio
My Commission Expires 06-18-2022

VERIFICATION

DISTRICT ~~**STATE OF**~~ OF COLUMBIA)
COUNTY OF N/A) **SS:**
)

The undersigned, Molly Suda, Associate General Counsel, being duly sworn, deposes and says that she has personal knowledge of the matters set forth in the foregoing data requests, and that the answers contained therein are true and correct to the best of her knowledge, information and belief.

Molly Suda

Molly Suda Affiant

Subscribed and sworn to before me by Molly Suda on this 10TH day of April, 2019.

Arthur J Burket

NOTARY PUBLIC

ARTHUR J. BURKET
NOTARY PUBLIC
EXP.
9-14-21
DISTRICT OF COLUMBIA

My Commission Expires: ARTHUR J. BURKET
NOTARY PUBLIC DISTRICT OF COLUMBIA
My Commission Expires September 14, 2021

KyPSC Case No. 2018-00195
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STAFF-DR-02-001

REQUEST:

Refer to the 2017 Integrated Resource Plan (IRP), page 11, subsection B.

a. Describe the industries in which new and existing customers are expressing a desire for greener renewable energy alternatives including the current load represented by these customers by customer class.

b. Describe the significant investments and expansions these customers are making in Duke Kentucky's system, including the potential new load these customers (by customer class) will add to the system.

c. Explain if Duke Ohio and Duke Indiana are experiencing the same phenomenon.

d. Duke Kentucky states that it is looking for opportunities to add more renewable resources to its generation fleet. Explain whether its customers are expressing a preference for a particular type of renewable energy or some combination of wind, solar, storage, and hydro that is the most cost effective and meets the customers' specific needs.

e. Explain whether these customers are expressing a distinct preference for the method of generation by which Duke Kentucky provides that energy.

f. Explain whether these customers would accept Duke Kentucky purchasing the green energy solely on their behalf as opposed to Duke Kentucky building and owning the green energy source.

RESPONSE:

a. Customers in the following industries have expressed a desire for power from renewable resources (load listed for those customers who have expressed an interest):

    a. Consumer packaged goods and e-commerce – projected 30 MW
    b. K-12 Schools – 16 MW
    c. Transportation – 12 MW
    d. Manufacturing – 4 MW

b. In terms customers adding new load, a large customer is investing $1+ billion in their new building/facility.

c. Yes.

d. The conversations with customers to date have focused primarily on solar energy.

e. Customers have expressed interest in having Duke Energy Kentucky build, own and maintain these systems, even if they are co-located at their facilities.

f. Customers have expressed a preference for a tangible relationship with specific renewable energy resources, with direct proximity to their operations the most preferable.

PERSON RESPONSIBLE: Andrew Ritch
Michael Pahutski

STAFF-DR-02-002

REQUEST:

Refer to the IRP, page 11, subsection B and page 17.

a. From an economic development or load growth perspective, explain whether Duke Kentucky has any commercial/industrial customers purchasing only green energy or wanting to purchase more.

b. Explain how Duke Kentucky is currently providing green energy to the commercial/industrial rate customers.

c. Explain whether any of these customers are willing to solely bear the cost of dedicated green energy that is provided on their behalf.

d. Explain whether Duke Kentucky intends to socialize the cost of the planned 10 MW solar and 2 MW storage installations across all of its customer classes. If no, explain how the costs will be apportioned across the rate groups.

RESPONSE:

a. Yes. We presently have several large customers who are interested in offsetting 100% of their electric load with renewable energy, and we anticipate that there will be other customers with similar preferences.

b. Duke Energy Kentucky purchases RECs/SRECs on behalf of participating customers, through our GoGreen Kentucky Tariff. Duke Energy Kentucky also purchases RECs for a customer under a Commission-approved special agreement.

c. Yes. In the case where specific customers have a need for green energy that surpasses that within the Duke Energy Kentucky portfolio of assets, these interested customers have expressed willingness to bear this incremental cost. It should also be noted that some customers have expressed that they cannot afford to solely bear the cost of renewable resources.

d. Because these assets are being built to augment and diversify the generation portfolio that all Duke Energy Kentucky customers rely upon, these costs and benefits will be allocated to all Duke Energy Kentucky customers.

PERSON RESPONSIBLE: Andrew Ritch
Michael Pahutski

Duke Energy Kentucky
Case No. 2018-00195
STAFF Second Set Data Requests
Date Received: March 27, 2019

STAFF-DR-02-003

REQUEST:

Refer to the IRP, page 11 and 17, subsection B. From an economic development and green energy perspective:

a. Explain if Duke Kentucky lost any potential large customers to neighboring contiguous states. If yes, explain if the potential customers are located in an affiliate sister company's service territory.

b. If Duke Kentucky has lost potential customers to Duke Ohio or Duke Indiana, explain the factors that played against Duke Kentucky and of these factors, provide which were beyond Duke Kentucky's ability to influence.

c. Explain how Duke Kentucky competes with Duke Ohio and Duke Indiana for a large load customer who is looking to locate regionally and who is looking at potential sites located in all three service territories.

d. Explain whether Duke Kentucky has lost any customers because it could not furnish acceptable green energy, whether self-generated or purchased. If yes, explain the customer's reasons for choosing another service company over Duke Kentucky.

RESPONSE:

a. Duke Energy is not aware of losing any potential large customers to neighboring contiguous states from an economic development and green energy perspective.

b. N/A

c. Duke Energy Ohio, Kentucky, and Indiana each works closely with local economic development organizations to recruit large customers to their respective service territories. We work the project with respect to the specific offerings we can apply in each individual state; we do not decide where we feel the greatest benefit might be for the prospect company. The prospect company decides on its preferred location based on numerous factors, including available work force, access to transportation corridors, state and local incentives, and what utility-offered products/services and infrastructure costs best benefit their project if they are looking within our separate service territories.

d. Duke Energy is not aware of losing any customers because it could not furnish acceptable green energy, whether self-generated or purchased.

PERSON RESPONSIBLE: Rhonda Whitaker
Michael Pahutski

STAFF-DR-02-004

REQUEST:

Refer to the IRP, page 11-12.

a. Explain whether there are any PJM requirements that would limit Duke Kentucky's options for providing increased amounts of green energy to potential or existing customers.

b. Explain whether there are policies, regulatory conditions or other requirements that limit Duke Kentucky's ability to successfully attract new larger load customers.

RESPONSE:

a. As a load serving entity in PJM, Duke Energy Kentucky is required to comply with the requirements in PJM OATT, Reliability Assurance Agreement, and the Operating Agreement in providing capacity to meet native load customers. Unlike traditional forms of generations, the unique attributes of renewable energy sources, particularly intermittency, impact the capacity value PJM associates with these types of generation. Consequently, to meet a specific PJM load obligation, surplus green generation must be acquired. Additionally, if committed to the PJM capacity market through either RPM or in an Fixed Resource Requirement Plan, these intermittent resources may not be available to PJM during critical load demand periods and could expose customers to Capacity Performance deficiency assessments. As an example, a PJM Capacity Performance assessment hour that occurs during a pre-sunrise winter peak could not be met with solar generation.

b. In 2017, Ohio passed House Bill 26, which permits natural gas companies to recover the prudently incurred costs associated with installing or constructing natural gas infrastructure to serve an economic development project. House Bill 26 enables natural gas companies to build infrastructure in advance of customers actually siting in an economic development project area, making that site more attractive to prospective customers.

   In addition, Duke Energy Indiana has implemented its Economic Development Rider that offers greater flexibility and value in structuring economic development incentives to attract business to its service territory.

   Similar programs in Kentucky would help to attract business to the Commonwealth.

PERSON RESPONSIBLE: John Verderame – a.
Rhonda Whitaker – b.

Duke Energy Kentucky
Case No. 2018-00195
STAFF Second Set Data Requests
Date Received: March 27, 2019

STAFF-DR-02-005

REQUEST:

Refer to the IRP, pages 12 and 13, and Appendix C. Identify and explain any violations of any federal, state, or local environmental laws and regulations since Duke Kentucky's last IRP.

RESPONSE:

Since the last IRP in 2014, Duke Energy Kentucky received no Notices of Violation (NOVs) for federal, state or local environmental laws and regulations. There were two small releases of transformer oil from the Duke Erlanger Operations Center into storm drains. There were two releases of oil to the Ohio River from East Bend Station. There was bottom ash sluice water released into an NPDES permitted storm water outfall from East Bend Station. There was oil released to the Ohio River from Miami Fort Station on February 17, 2015. All releases were stopped, properly reported, cleaned up and no NOVs were issued.

PERSON RESPONSIBLE: Tammy Jett

Duke Energy Kentucky
Case No. 2018-00195
STAFF Second Set Data Requests
Date Received: March 27, 2019

STAFF-DR-02-006

REQUEST:

Refer to the IRP, pages 13, 16-17 and 28.

a. Explain how many of Duke Kentucky's natural gas customers have the option to install electric heat.

b. Of the natural gas customers having access to Duke Kentucky electric service, provide the proportion that utilizes electric heat rather than natural gas.

c. When a new customer is building in the territory served by natural gas, explain whether both electric and gas heating is offered. On average, provide which is more economical for the customer for the various customer rate groups.

d. Explain the approximate impact on winter peak if all of the customers with Duke Kentucky electric heat residing in Duke Kentucky's natural gas service territory switched to dual fuel heat pumps as opposed to other efficient heat pumps.

RESPONSE:

a. Because natural gas furnaces require electricity to operate, all customers that use natural gas for space heating should have the ability to install electric heat. Some Duke Energy Kentucky gas customers receive electric service from sources other than Duke Energy Kentucky. As of February 2019, about 22,000 of Duke Energy Kentucky's 101,000 gas customers receive electric service from an entity other than Duke Energy Kentucky. Therefore, about 79,000 Duke Energy Kentucky gas customers could install electric heat that is also served by the Company.

b. As of February 2019, Company records show that about 34,000 Duke Energy Kentucky customers use electric heat. Duke Energy Kentucky has about 79,000 combination customers (customers receiving both gas and electric service from the Company). The number of Duke Energy Kentucky combination customers that utilize electric heat is not available.

c. Objection. This question is vague, overbroad and cannot be answered without speculation as to what is meant by a new customer building in the service territory served by natural gas. Without waiving said objection, as indicated above, Duke Energy Kentucky's electric and natural gas service territories are not completely identical. There are some areas that are electric only, there are some areas that are natural gas only and some areas that are combination. Duke Energy Kentucky offers to provide the gas and/or electric service necessary to meet the customer's stated energy needs as limited by our respective service territories. In areas where combination gas and electric service is available from Duke Energy Kentucky, generally it is the customer or builder/ developer who determines which service is more desirable/economical.

d. To respond to this item, we provide some back-of-the-envelope figures in the hope that a guess will be informative, without approaching the level of rigor that undergirds other parts of the load forecast. Typically, the heating end use predicts about 48% of the winter peak for Duke Energy Kentucky. ITRON data on end-use suggest that residential customers account for 87% of that, or about 42% of the total peak. Based on the data given in parts A-B, 34,000 customers currently use electric heat. Were 79,000 additional customers to be added to the electric heat demand at time of peak, that would imply heating end use at time of peak that was 156% of the business-as-usual winter peak (this is calculated by multiplying 42% by 79/34 and adding it to the non-residential-heating load of 58% of winter peak). So—in this extreme case—demand for energy at time of winter peak should increase by slightly more than half.

PERSON RESPONSIBLE: James E. Ziolkowski – a., b.
Benjamin W. Passty, Ph.D. – c., d.

Duke Energy Kentucky
Case No. 2018-00195
STAFF Second Set Data Requests
Date Received: March 27, 2019

STAFF-DR-02-007

REQUEST:

Refer to the IRP, pages 17 and 23.

a. Explain whether Duke Kentucky is aware of institutional investors or pension funds urging electric generation utilities to be carbon-free by 2050.

b. Explain whether Duke Kentucky corporately set a goal to reduce its carbon emissions by 40 percent from 2005 levels. If yes, explain how Duke Kentucky's East Bend unit is affect by this goal.

RESPONSE:

a. Duke Energy Kentucky is aware of certain institutional investors calling on electric utilities to commit to carbon free emissions by 2050. For example, the New York City Comptroller, in a letter dated February 26, 2019 and signed by a coalition of large investors with approximately $1.8 trillion of assets under management, urged every utility to set a goal of net-zero carbon emissions by 2050 at the latest. These investors see this commitment to a more sustainable business model as the best way to reduce significant risks to electric utilities while protecting their clients' interest. Below is a link to the letter referenced above:

https://www.eenews.net/assets/2019/03/01/document_ew_01.pdf

b. The 2017 Climate Report to Shareholders reaffirmed Duke Energy's commitment to a 40% CO_2 reduction by 2030. This reduction is an enterprise goal, and does not apply solely to an asset or jurisdiction. Emissions from Duke Energy Kentucky roll up to the enterprise level; neither Duke Energy Kentucky, nor East Bend, was held to a specific reduction.

PERSON RESPONSIBLE: John L. Sullivan – a.
Heather E. Quinley – b.

Duke Energy Kentucky
Case No. 2018-00195
STAFF Second Set Data Requests
Date Received: March 27, 2019

STAFF-DR-02-008

REQUEST:

Refer to the IRP, pages 18, Figure 2.4.

a. Explain whether the Energy Mix Figure portrays how much of the energy is supplied by Duke Kentucky East Bend coal Unit 2, Woodsdale CT units, and the PJM market.

b. Explain whether the Energy Mix Figure also means that the East Bend Unit 2's cost is such that PJM selects it to run to the point that it provides 87 percent of the energy consumed by Duke Kentucky's customers. If not, explain the energy mix based upon how often the units in Duke Kentucky's generation fleet are selected to run by PJM.

RESPONSE:

a. Correct. The 87% of energy provided by "Coal" in figure 2.4 refers to East Bend 2 and the 0.3% of energy provided by "CT" refers to Woodsdale CT's 1-6. The remaining 13% of energy required by the DEK system was provided by purchases from the PJM market.

b. Correct. During 2017, the East Bend unit was dispatched by PJM in such a manner that resulted in this unit supplying 87% of the Duke Energy Kentucky customer demand.

PERSON RESPONSIBLE: Scott Park – a.
John Swez/John Verderame – b.

Duke Energy Kentucky
Case No. 2018-00195
STAFF Second Set Data Requests
Date Received: March 27, 2019

PUBLIC STAFF-DR-02-009

REQUEST:

Refer to the IRP, pages 22 and 71. Provide the Moody's Analytics reports upon which Duke Kentucky relied upon as the basis for its load forecasts.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment only)

The information from Moody's was delivered to us as a database extract for selected series, NOT a report. The data is proprietary and available on a subscription basis. The series are included in STAFF-DR-02-009 Confidential Attachment that presents historical series and forecast series together.

PERSON RESPONSIBLE: Benjamin W. Passty, Ph.D.

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STAFF-DR-02-009 ATTACHMENT

PROVIDED ON CD FILED UNDER SEAL

PUBLIC STAFF-DR-02-010

REQUEST:

Refer to the IRP, page 24. Provide the Annual Energy Outlook (AEO) forecast factors and the additional third-party capital cost projections and explain how they were combined.

RESPONSE:

CONFIDENTIAL PROPRIETARY TRADE SECRET (As to Attachment only)

The Integrated Resource Plan (IRP) has traditionally modeled new generation using Overnight Capital Costs from a single third-party vendor which are then projected forward using the AEO forecast factors for all technologies. Beginning in 2016, the company's Distributed Energy Technology (DET) group introduced a new 10-year Forecast for Renewables (i.e. Solar PV, Wind, and Batteries) which is provided by a separate third-party vendor who specializes in renewable technologies. Since the IRP requires a forecast beyond 10 years for these renewable technologies, the DET capital cost forecast for renewable technologies is utilized for the first 10 years and then projected from that point utilizing the AEO forecast factors. All other technologies continue to be projected in the traditional manner.

Please see STAFF-DR-02-10 Confidential Attachment for the AEO forecast factors and capital cost projections.

PERSON RESPONSIBLE: Scott Park

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Forecast Factor Table

Year	F Frame CT	J Class CC	Reciprocating Engines	Ultra-Supercritical Pulverized Coal	IGCC	Nuclear	Onshore Wind	Solar PV	Battery Storage	CHP
2018	[redacted]									
2019										
2020										
2021										
2022										
2023										
2024										
2025										
2026										
2027										
2028										
2029										
2030										
2031										
2032										

Blended Capital Cost Forecast in $/kW

(Real $)	(Real $)	(Real $)	(Real $)	(Real $)	(Real $)	(Real $)	(Real $)	(Nominal $)	(Nominal $)	(Real $)
Year	F Frame CT	J Class CC	Reciprocating Engines	Ultra-Supercritical Pulverized Coal	IGCC	Nuclear	Onshore Wind	Solar PV	Battery Storage	CHP
2018	[redacted]									
2019										
2020										
2021										
2022										
2023										
2024										
2025										
2026										
2027										
2028										
2029										
2030										
2031										
2032										

Notes:
[redacted]

CONFIDENTIAL PROPRIETARY TRADE SECRET

Blended Capital Cost Forecast in $/kW (Real $)

Escalation Rate: [redacted]

Year	F Frame CT	J Class CC	Reciprocating Engines	Ultra-Supercritical Pulverized Coal	IGCC	Nuclear	Onshore Wind	Solar PV	Battery Storage	CHP
2018	[redacted]									
2019										
2020										
2021										
2022										
2023										
2024										
2025										
2026										
2027										
2028										
2029										
2030										
2031										
2032										

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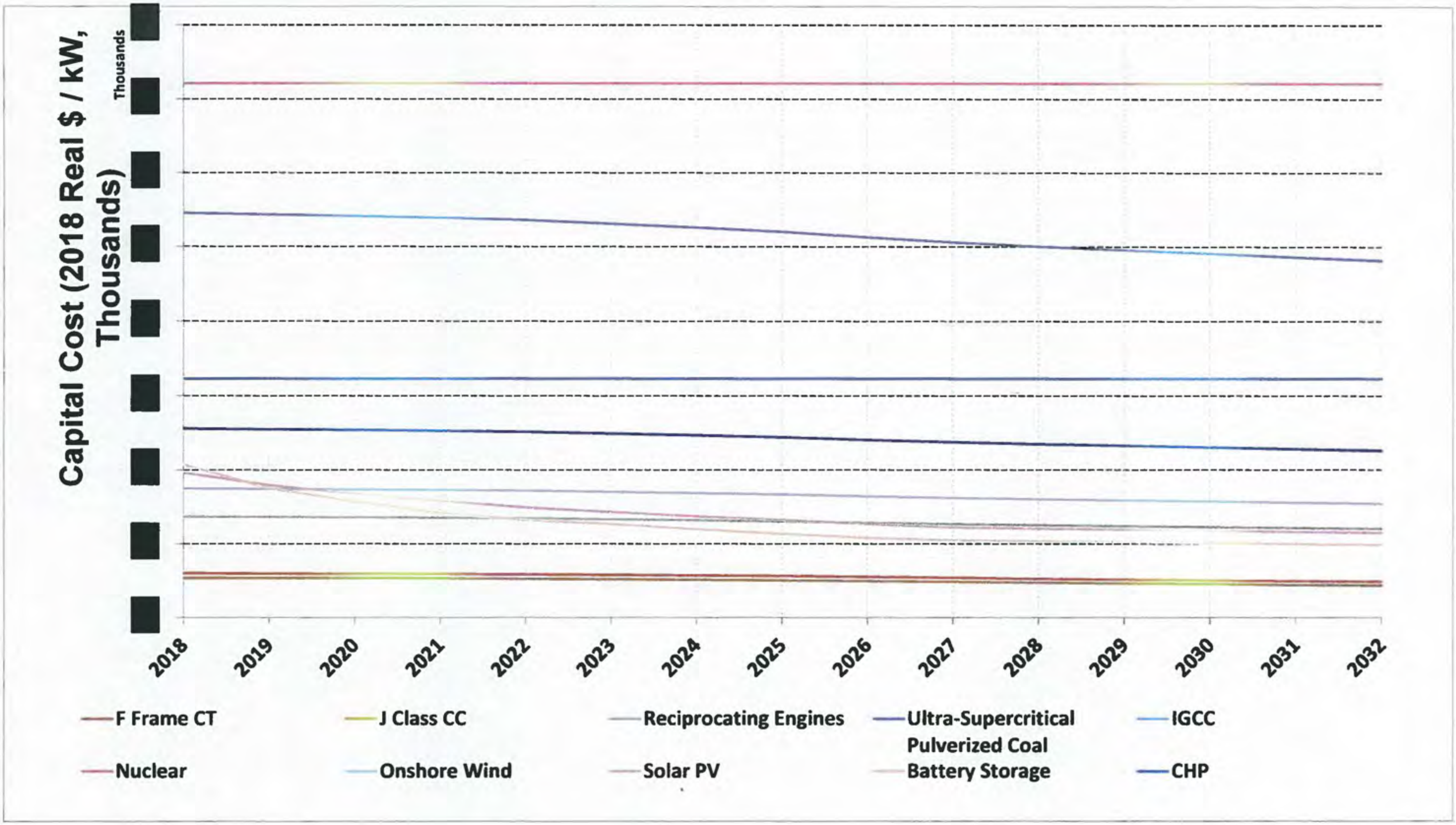

STAFF-DR-02-011

REQUEST:

Refer to the IRP, pages 25 and 33; subsection E.

a. Explain whether landfill gas as a supply-side generation option is not available or not feasible. If not feasible, explain why.
b. Explain why a nuclear station is considered a viable option to include as an option for supply-side consideration given the associated cost, licensing and regulatory approval timelines and siting difficulties.
c. Explain the reasonable possible sites in Duke Kentucky's territory where a nuclear facility could be located.
d. Explain how close to commercial viability small modular nuclear reactors are.
e. Explain whether Duke Kentucky considers the siting and construction of a new coal unit, regardless of combustion technology, could be economically viable.
f. Table 4.1 lists supply-side resource options that meet technical and commercial availability criteria. Explain which resource options, if any, have been screened for economic viability and list any that would be eliminated based upon cost.

RESPONSE:

a. Landfill gas projects are technically and commercially available but are not deemed feasible due to being difficult to site, limited in scale and not economic relative to competing gas-fired technologies. Landfill gas generating projects are typically niche applications driven by non-economic considerations. If landfill gas were included as a resource option in Table 4.1 on page 33 of the Duke Energy Kentucky

2018 Integrated Resource Plan, the overnight capital cost estimate of $3,978 would place it significantly higher than other gas-fired or renewable resource options.

b. Although new unit construction continues to face significant challenges, nuclear remains a viable supply side resource option which passes technical and commercial screening criteria. Nuclear is unique among currently viable technologies in its ability to supply consistent baseload power without CO_2 emissions and likely has a place in future energy supply if carbon constraints are imposed at the national or state level. Regulatory challenges, cost, and long construction timeframes remain an obstacle for new nuclear plant designs. However, as the initial reactors are of a new design are completed, the Company expects that cost and construction time will improve due to lessons learned from the initial units. As noted on page 31 of the Duke Energy Kentucky 2018 Integrated Resource Plan, no new nuclear was economically selected by the model.

c. Siting studies for new nuclear plants are typically performed only after determining that they are economically viable within the planning period of an Integrated Resource Plan due to the significant cost and lead time required to perform these studies. The Company has not pursued a siting study for a nuclear plant in the Duke Energy Kentucky service territory at this time; however, optimal siting for a nuclear plant is typically near bodies of water, such as lakes, rivers, or oceans in seismically-stable areas.

d. It is expected that Small Modular Reactors will be certified by the Nuclear Regulatory Commission within the next five years and will be commercially viable within the next five to ten years. The first deployment currently expected in the 2026 timeframe.

e. Although natural gas prices continue to remain at historically low levels, the Company continues to evaluate alternatives to baseload gas-fired generation. Fuel diversity is an important consideration due to uncertainty surrounding future fuel prices and environmental policy. Accordingly, Duke Energy continues to propose coal as an option for the Kentucky Integrated Resource Plan. As can be seen in the Duke Energy Kentucky 2018 Integrated Resource Plan, there are no new coal units economically selected by the model within the IRP planning period.

f. All technologies that pass the initial technical and commercial screenings are then screened for economic viability. The cost and performance data for each technology being screened is based on research and information from several sources. These sources include, but may not be limited to the following internal Departments: Duke Energy's Project Management & Construction, Emerging Technologies, and Generation & Regulatory Strategy. The following external sources have also been utilized: proprietary third-party engineering studies, the Electric Power Research Institute (EPRI) Technical Assessment Guide (TAG®), and Energy Information Administration (EIA). There were no resource options strictly eliminated due to economic viability as all technologies with major economic concerns were eliminated by the technical and commercial screenings.

PERSON RESPONSIBLE: Scott Park

REQUEST:

Refer to the IRP, page 27. Explain the drivers in Duke Kentucky's service territory of the strengthening economic output, especially in manufacturing; include a discussion of whether this is a result of Duke Kentucky's economic development efforts or part of a general regional and national strengthening of the economy.

RESPONSE:

The economic drivers used for our modeling differed by class, with the major class forecasts aggregated together into the retail forecast. Page 54 of the IRP lists the economic drivers used for each model. With regard to manufacturing, the model estimated an elasticity of 0.16 for the impact of Manufacturing GDP on electricity used by industrial-class customers, implying that about a 6% increase in regional manufacturing output—with all other things having been held equal—would be required to increase energy sales 1% (or about 8 gWh per year).

To put that 6% growth in industrial output into context, a brief manufacturing renaissance in early 2012 had growth at a rate of double that, according to data provided to us by Moody's analytics. The economic collapse of 2007-2009 saw output decline by a quarter, only to rebound by 16% during many months of 2010. However, the Moody's analytics forecast for manufacturing output beginning in 2019 and going into the future didn't have any year with an increase at or above this level, or even any YOY increase in excess of 3%. So in this context, Duke Energy's economic development efforts would have to produce an opportunity that would increase 4 gWh or more of incremental energy demand to make a difference.

The strengthening economic conditions in the Duke Energy Kentucky service territory is a combination of both, a general continued recovery of manufacturing, coupled with the state and regional economic development agencies along with our company's economic development efforts over the last number of years.

PERSON RESPONSIBLE: Benjamin W. Passty, Ph.D.

Duke Energy Kentucky
Case No. 2018-00195
STAFF Second Set Data Requests
Date Received: March 27, 2019

STAFF-DR-02-013

REQUEST:

Refer to the IRP, page 29. Provide the U.S. Energy Information Administration AEO report for 2018.

RESPONSE:

Please see STAFF-DR-02-013 Attachment.

PERSON RESPONSIBLE: Scott Park

Annual Energy Outlook 2018

with projections to 2050

Independent Statistics & Analysis
U.S. Energy Information Administration

#AEO2018

February 6, 2018
www.eia.gov/aeo

Annual Energy Outlook 2018
with projections to 2050

February 2018

U.S. Energy Information Administration
Office of Energy Analysis
U.S. Department of Energy
Washington, DC 20585

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slide number

Overview/key takeaways

EIA's *Annual Energy Outlook* provides modeled projections of domestic energy markets through 2050, and it includes cases with different assumptions regarding macroeconomic growth, world oil prices, technological progress, and energy policies. Strong domestic production coupled with relatively flat energy demand allows the United States to become a net energy exporter over the projection period in most cases. In the Reference case, natural gas consumption grows the most on an absolute basis, and nonhydroelectric renewables grow the most on a percentage basis.

The Annual Energy Outlook provides long-term energy projections for the United States

- Projections in the *Annual Energy Outlook 2018* (AEO2018) are not predictions of what will happen, but rather modeled projections of what may happen given certain assumptions and methodologies.
- The AEO is developed using the National Energy Modeling System (NEMS), an integrated model that captures interactions of economic changes and energy supply, demand, and prices.
- Energy market projections are subject to much uncertainty, as many of the events that shape energy markets and future developments in technologies, demographics, and resources cannot be foreseen with certainty.
- More information about the assumptions used in developing these projections will be available shortly after the release of the AEO.
- The AEO is published pursuant to the Department of Energy Organization Act of 1977, which requires the U.S. Energy Information Administration (EIA) Administrator to prepare annual reports on trends and projections for energy use and supply.

What is the Reference case?

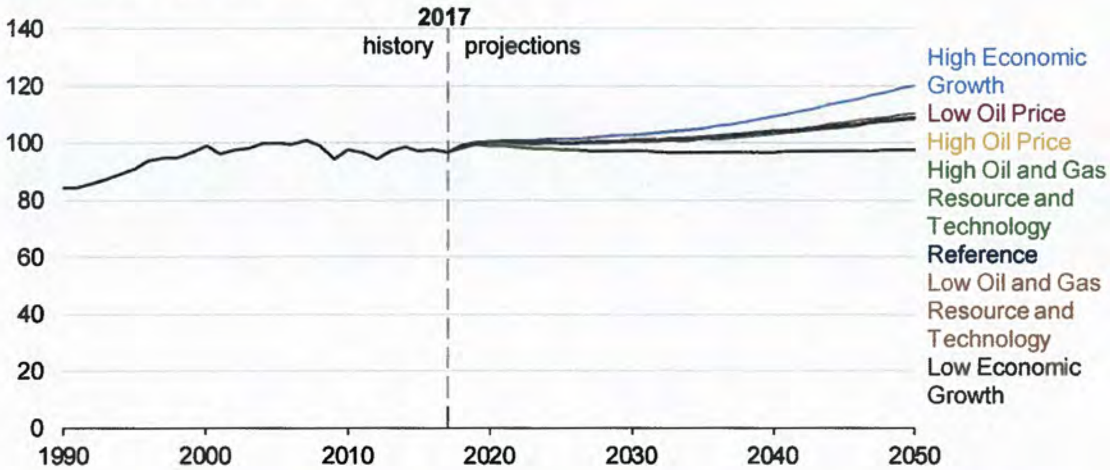
- The Reference case projection assumes trend improvement in known technologies along with a view of economic and demographic trends reflecting the current views of leading economic forecasters and demographers.
- The Reference case generally assumes that current laws and regulations affecting the energy sector, including sunset dates for laws that have them, are unchanged throughout the projection period.
- The potential impacts of proposed legislation, regulations, and standards are not included.
- EIA addresses the uncertainty inherent in energy projections by developing side cases with different assumptions of macroeconomic growth, world oil prices, technological progress, and energy policies.
- Projections in the AEO should be interpreted with a clear understanding of the assumptions that inform them and the limitations inherent in any modeling effort.

What are the side cases?

- Oil prices are driven by global market balances that are primarily influenced by factors external to the NEMS model. In the High Oil Price case, the price of Brent crude, in 2017 dollars, reaches $229 per barrel (b) by 2050, compared with $114/b in the Reference case and $52/b in the Low Oil Price case.
- In the High Oil and Gas Resource and Technology case, lower costs and higher resource availability than in the Reference case allow for higher production at lower prices. In the Low Oil and Gas Resource and Technology case, assumptions of lower resources and higher costs are applied.
- The effects of the economic assumptions on energy consumption are addressed in the High and Low Economic Growth cases, which assume compound annual growth rates for U.S. gross domestic product of 2.6% and 1.5%, respectively, from 2017–50, compared with 2.0%/year growth in the Reference case.
- Cases assuming the Clean Power Plan is implemented show how the presence of that policy could affect energy markets and emissions compared with the Reference, resource, economic, and oil price cases.
- AEO2018 will also include additional side cases—which are not discussed here—and will support a series of *Issues in Focus* articles that will be released in 2018.

Energy consumption is bounded by the High and Low Economic Growth cases—

Total energy consumption
quadrillion British thermal units

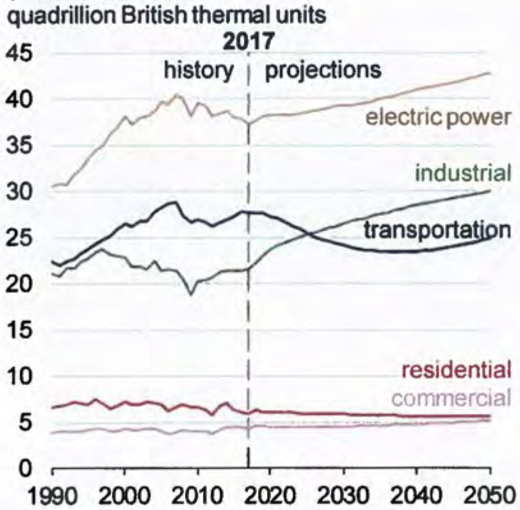


—and the spread of values increases in the last decade of the projection

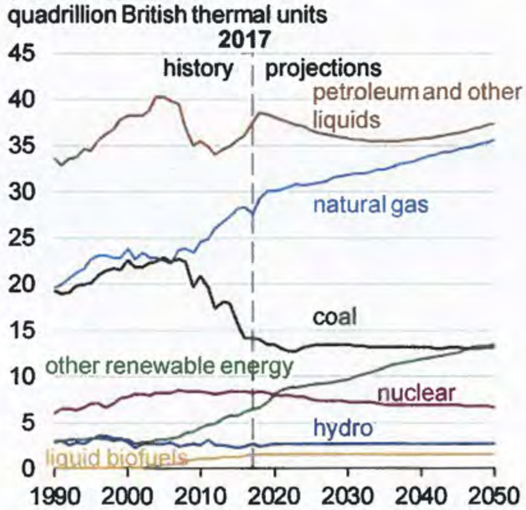
- In the Reference case, from 2017 to 2050, projected gross domestic product (GDP) grows annually at a rate of 2.0%, while projected energy consumption grows at 0.4%/year and surpasses its 2007 peak by 2033.
- In the High Economic Growth case, GDP grows by 2.6%/year from 2017 to 2050, while energy consumption grows by 0.7%. In the Low Economic Growth case, in which GDP grows 1.5% annually, energy consumption is essentially flat.
- By 2050, total energy consumption in the High Economic Growth case and Low Economic Growth case ranges from 10% more than and 10% less than, respectively, the Reference case.

The fuel mix of U.S. consumption changes over the projection period in the Reference case—

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



Energy consumption by fuel (Reference case)
quadrillion British thermal units

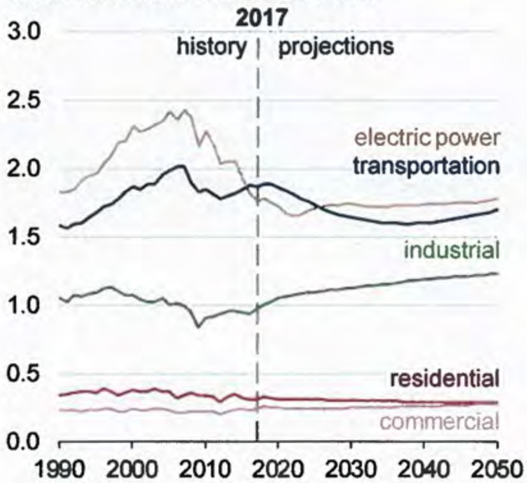


—with natural gas and renewables growing the most

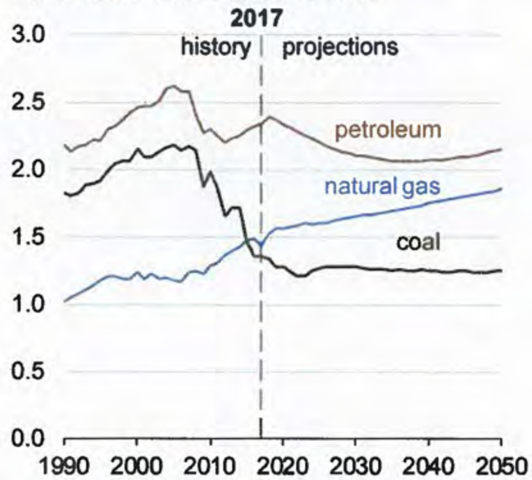
- Natural gas grows the most on an absolute basis in the Reference case projection and nonhydroelectric renewables grows the most on a percentage basis.
- The industrial sector accounts for the most growth in natural gas consumption, with expanding use in the chemical industries; for industrial heat and power; and for liquefied natural gas production. Natural gas consumption also increases significantly in the power sector as a result of the scheduled expiration of renewables tax credits in the mid-2020s.
- A combination of reductions in technology costs and implementation of policies that encourage the use of renewables at the state level (renewable portfolio standards) and at the federal level (production and investment tax credits) drives down the costs of renewables technologies (wind and solar photovoltaic), supporting their expanded adoption.

Energy-related carbon dioxide emissions mirror the trends in energy consumption across cases—

Energy-related carbon dioxide emissions by sector (Reference Case)
billion metric tons of carbon dioxide



Energy-related carbon dioxide emissions by fuel (Reference case)
billion metric tons of carbon dioxide

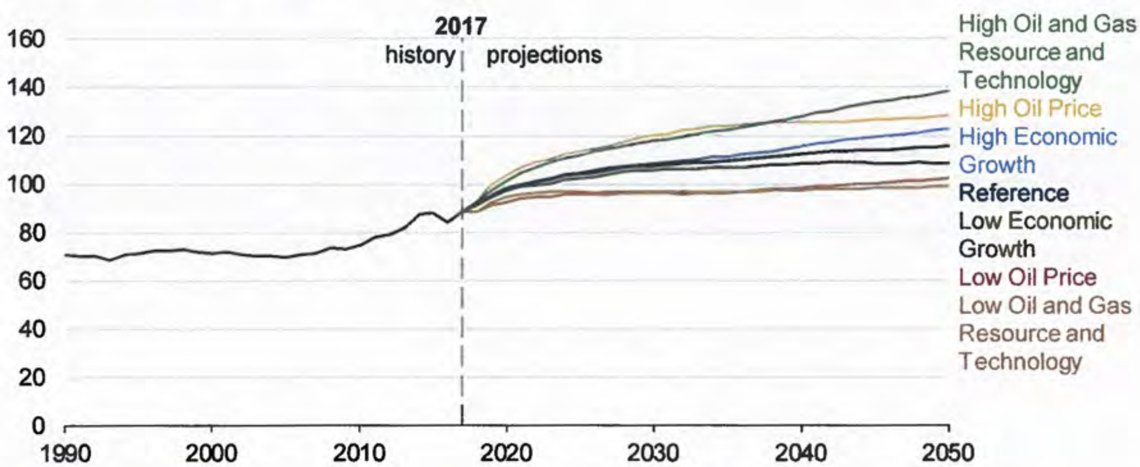


—and are essentially flat in the Reference case

- Energy-related CO2 emissions from the industrial sector grow the most on both an absolute and relative basis—0.6% annually—from 2017 to 2050 in the Reference case. Natural gas has the largest share of both energy and CO2 emissions in the industrial sector throughout the projection period. The relatively low cost of natural gas leads to further increases in usage and emissions.
- Electric power sector CO2 emissions are relatively flat in the Reference case through 2050 as a result of favorable market conditions for natural gas and supportive policies for renewables compared with coal.
- Commercial sector emissions grow at a rate of 0.1% annually from 2017 to 2050, as higher energy use in the sector is only partially offset by efficiency gains. CO2 emissions in the residential and transportation sectors both decline by 0.2%/year over the projection period.
- Natural gas emissions grow at an annual rate of 0.8%, while petroleum and coal emissions decline at annual rates of 0.3% and 0.2%, respectively. Petroleum emissions rise in each of the final 13 years of the projection period, when increased vehicle usage outweighs efficiency gains.

Energy production growth depends on technology, resources, and market conditions—

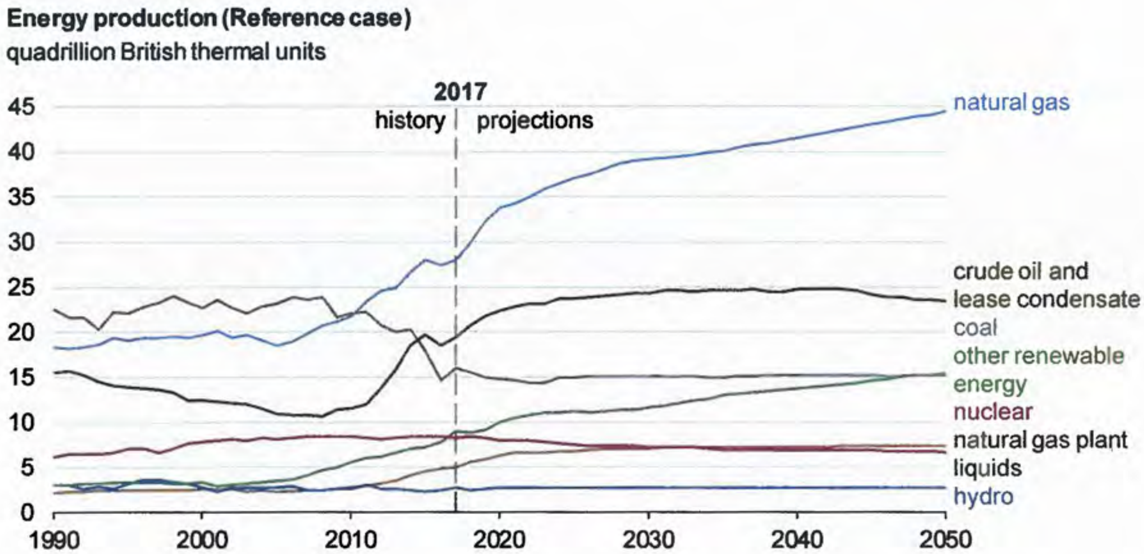
Total energy production
quadrillion British thermal units



—making production more sensitive than consumption to side case assumptions

- Total U.S. energy production increases by about 31% from 2017 through 2050 in the Reference case, led by increases in the production of renewables other than hydropower, natural gas, and crude oil (although crude oil production only increases during the first 15 years of the projection period).
- Projected U.S. energy production is closely tied to assumptions about resources, technology, and prices, which is evident in side cases that vary these assumptions.
- The range of total production is bounded by the resource cases, which address the uncertainty in U.S. oil and natural gas resources and technology. The High Oil and Gas Resource and Technology case assumes higher estimates than the Reference case of unproved Alaska resources; offshore Lower 48 resources; and onshore Lower 48 tight oil, tight gas, and shale gas resources. This side case also assumes lower costs of producing these resources and faster technology improvement. The Low Oil and Gas Resource and Technology case assumes the opposite.
- The High Oil Price case reflects the impact of higher world demand for petroleum products, lower Organization of the Petroleum Exporting Countries (OPEC) upstream investment, and higher non-OPEC exploration and development costs. The Low Oil Price case assumes the opposite.

In the Reference case, natural gas accounts for the largest share of total energy production—



—while renewables other than hydropower grow the most on a percentage basis

- Natural gas production accounts for nearly 39% of U.S. energy production by 2050 in the Reference case. Production from shale gas and tight oil plays as a share of total U.S. natural gas production is projected to continue to grow because of the large size of the associated resources.

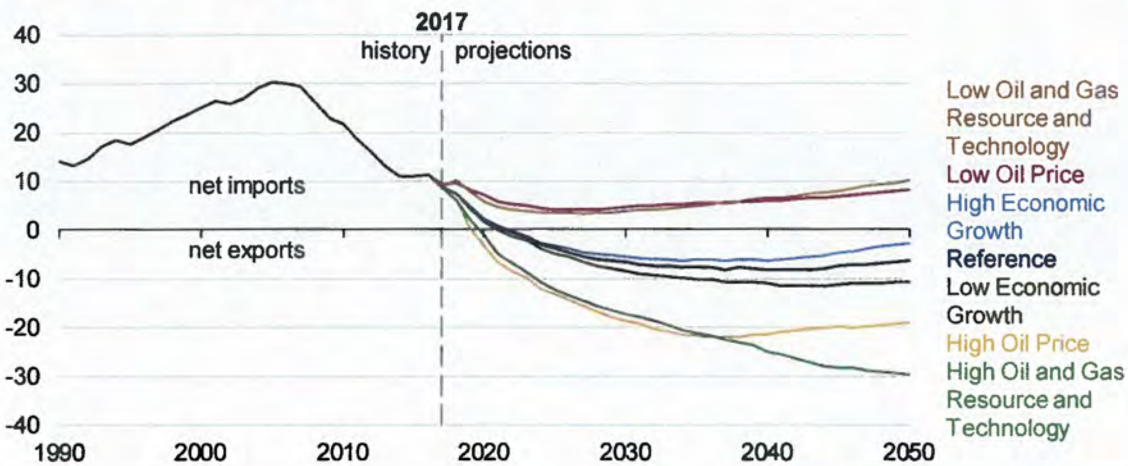
- Wind and solar generation leads the growth in renewables generation throughout the projection, accounting for 64% of the total electric generation growth in the Reference case through 2050. With a continued (but reduced) tax credit and declining capital costs, solar capacity continues to grow throughout the projection period, while tax credits that phase out for plants entering service through 2024 provide incentives for new wind capacity in the near term.

- In the Reference case, U.S. crude oil production in 2018 is projected to surpass the 9.6 million barrels per day (b/d) record set in 1970 and will plateau between 11.5 million b/d and 11.9 million b/d. The continued development of tight oil and shale gas resources supports growth in natural gas plant liquids production, which reaches 5.0 million b/d in 2023 in the Reference case—a nearly 35% increase from the 2017 level.

- Hydropower, nuclear power, and coal production are relatively flat in the Reference case through 2050, limited by slow growth in electricity demand as well as unfavorable economics and other considerations.

The United States is a net energy exporter in all but two cases—

Net energy trade
quadrillion British thermal units

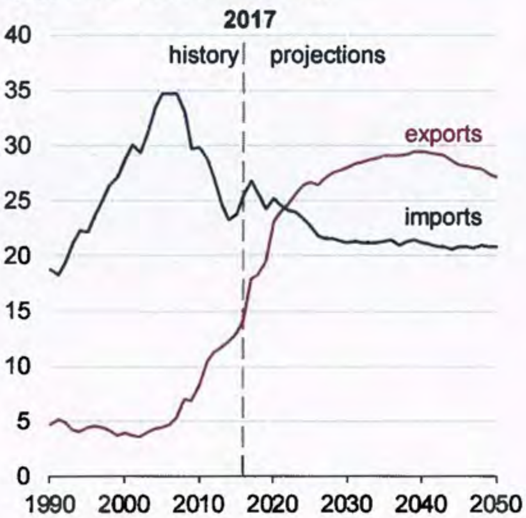


—and in the High Oil and Gas Resource and Technology case, net exports continue to increase through 2050

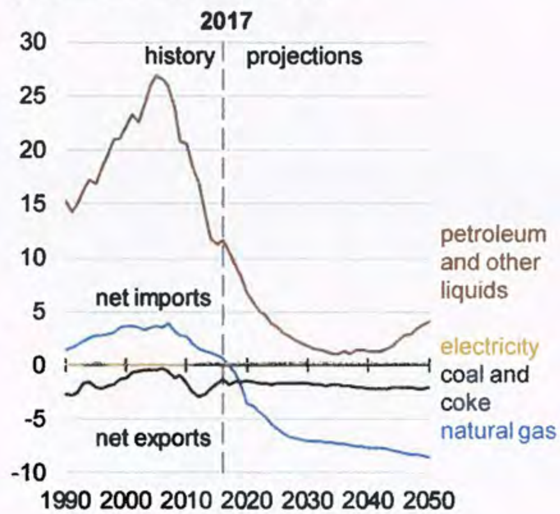
- The United States is projected to become a net energy exporter by 2022 in the Reference case projection, but the transition occurs earlier in three of the AEO2018 side cases.
- In the High Oil and Gas Resource and Technology case, favorable geology and technological developments lead to oil and natural gas production at lower prices, supporting exports that increase over time.
- In the High Oil Price case, before 2038, economic conditions are favorable for oil producers. Higher prices support higher levels of exports, but lower domestic consumption. After 2038, exports decline as a result of the lack of substantial improvements in technology, and production moves to less-productive regions.
- With less favorable geology and technology, as assumed in the Low Oil and Gas Resource and Technology case, and low world oil prices, as assumed in the Low Oil Price case, the United States remains a net energy importer.

Even though the United States becomes a net energy exporter in the Reference case—

Energy trade (Reference case)
quadrillion British thermal units



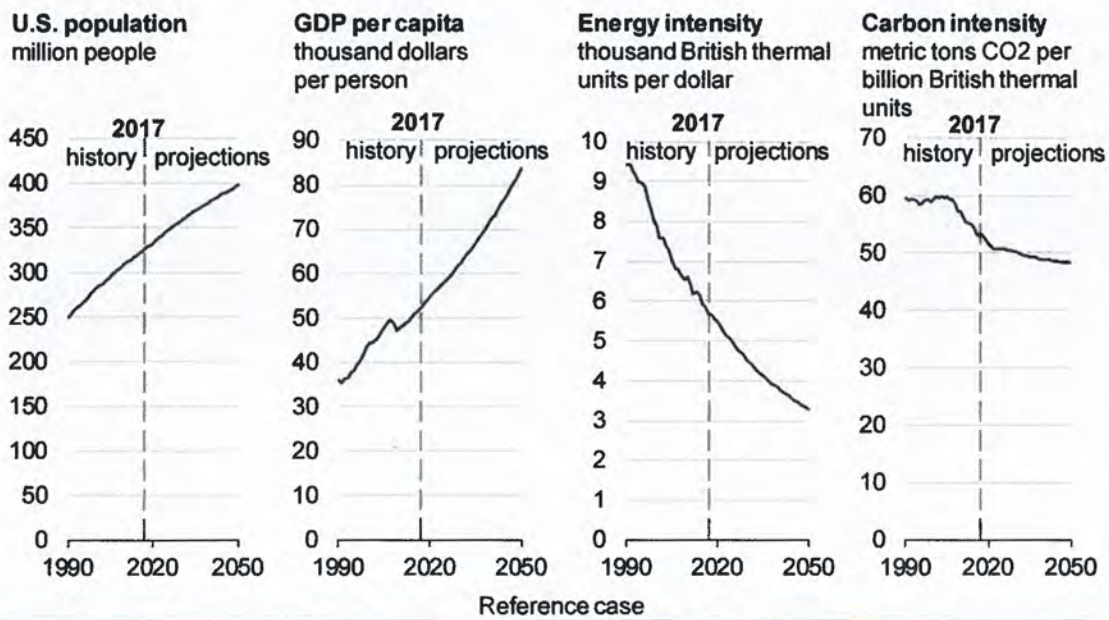
Net energy trade (Reference case)
quadrillion British thermal units



—both imports and exports continue through the projection period

- The United States has been a net energy importer since 1953, but declining energy imports and growing energy exports make the United States a net energy exporter by the early 2020s in the Reference case.
- Historically and in the projection, most U.S. energy trade is in crude oil and petroleum products. The United States remains both an importer and exporter of petroleum liquids, importing mostly crude oil and exporting mostly petroleum products such as gasoline and diesel through 2050 in the Reference case. The United States remains a net importer of petroleum and other liquids on an energy basis.
- U.S. natural gas trade, which historically was shipments by pipeline from Canada and to Mexico, is projected to be increasingly dominated by liquefied natural gas exports to more distant destinations.
- The United States continues to be a net exporter of coal (including coal coke) through 2050, but its export growth is not expected to increase significantly because of competition from other global suppliers closer to major markets.

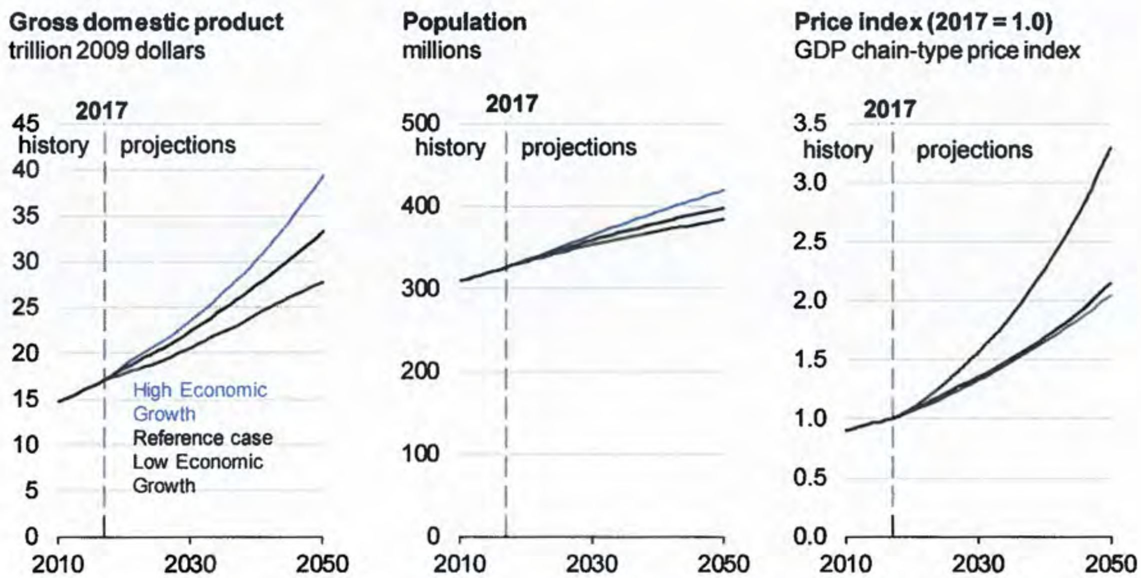
Although population and economic output per capita continue rising in the Reference case—



—declines in energy intensity and carbon intensity mitigate emissions growth

- In the United States, the amount of energy used per unit of economic growth (energy intensity) has declined steadily for many years, while the amount of CO_2 emissions associated with energy consumption (carbon intensity) has generally declined since 2008.
- These trends are projected to continue as energy efficiency, fuel economy improvements, and structural changes in the economy all lower energy intensity.
- Carbon intensity declines as a result of changes in the U.S. energy mix that reduce the consumption of carbon-intensive fuels and increase the use of low- or no-carbon fuels.
- By 2050, energy intensity and carbon intensity are 42% and 9% lower than their respective 2017 values in the Reference case, which assumes the laws and regulations currently in place.

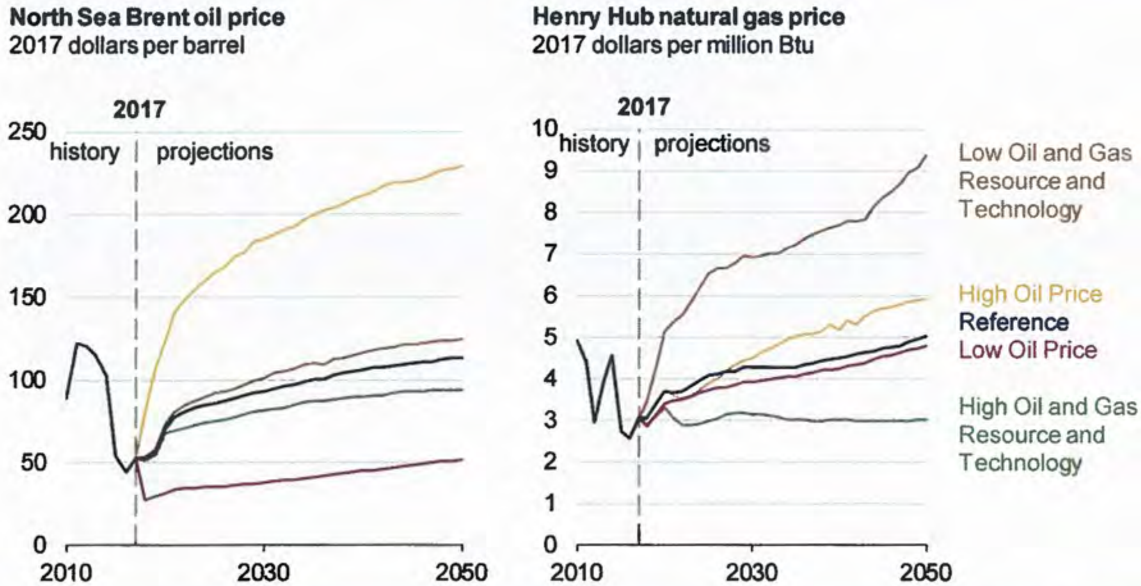
Different macroeconomic assumptions address the energy implications of the uncertainty—



—inherent in future economic growth trends

- The Reference, High Economic Growth, and Low Economic Growth cases illustrate three possible paths for U.S. economic growth. The High Economic Growth case assumes higher annual growth and lower annual inflation rates (2.6% and 2.2%, respectively) than in the Reference case (2.0% and 2.3%, respectively), while the Low Economic Growth case assumes lower annual growth and higher annual inflation rates (1.5% and 3.7%, respectively) than in the Reference case.
- In general, higher economic growth (as measured by gross domestic product) leads to greater investment, increased consumption of goods and services, more trade, and greater energy consumption.
- Differences among the cases reflect different expectations for growth in population, labor force, capital stock, and productivity. These changes affect growth rates in household formation, industrial activity, and amounts of travel, as well as investment decisions about energy production.
- All three economic growth cases assume smooth economic growth and do not anticipate business cycles or large economic shocks.

Assumptions about the size of U.S. resources and the improvement in technology affect domestic oil and natural gas prices—



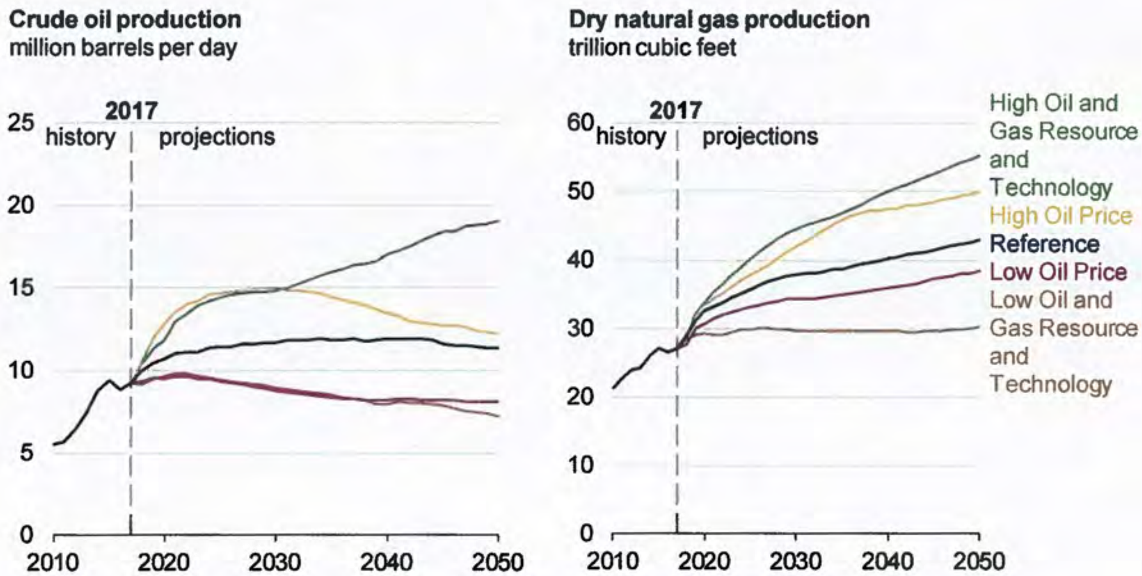
—but global market conditions play a more significant role in oil price projections

- In real terms, crude oil prices in 2016 (based on the global benchmark North Sea Brent) were at their lowest level since 2004, and natural gas prices (based on the domestic benchmark Henry Hub) were the lowest since before 1990. These prices increased modestly in 2017, and this trend continues over the projection period in all cases except the High Oil and Gas Resource and Technology case.

- Natural gas prices are highly sensitive to domestic resource and technology assumptions explored in the side cases. Across all cases, to satisfy the growing demand for natural gas, production expands into more expensive-to-produce areas, putting upward pressure on production costs and prices.

- Crude oil prices in the Reference case are projected to rise at a faster rate in the near term than in the long term because of weak near-term investment coupled with strong demand. At the same time, domestic and export market demand growth drives an increase in natural gas prices at the U.S. benchmark Henry Hub in the Reference case, despite technological advances supporting production.

Although world oil prices play a role in U.S. crude oil and natural gas production—



—resource availability and technological improvements are more significant determinants of domestic production levels

- Projections of tight oil and shale gas production are uncertain because large portions of the known formations have relatively little or no production history, and extraction technologies and practices continue to evolve rapidly. Continued high rates of drilling technology improvement could increase well productivity and reduce drilling, completion, and production costs.

- In the High Oil and Gas Resource and Technology case, crude oil and natural gas production both continue to grow through 2050.

- Crude oil prices affect natural gas production primarily through changes in global natural gas consumption, U.S. natural gas exports, and natural gas produced from oil formations (associated gas).

- In the High Oil Price case, the difference between crude oil and natural gas prices creates a greater incentive to consume natural gas in energy-intensive industries, for transportation, and to export overseas as liquefied natural gas, all of which drive U.S. production upward. Without the more favorable resources and technological developments in the High Oil and Gas Resource and Technology case, U.S. crude oil production begins to decline in the High Oil Price case in the early 2030s, and by 2050 crude oil production is nearly the same as in the Reference case.

Critical drivers and uncertainty

Various factors influence the model results in AEO2018, including: new and existing laws and regulations, updated data, and model improvements since AEO2017.

New laws and regulations reflected in the Reference Case

- The Clean Power Plan is not included in the *Annual Energy Outlook 2018* (AEO2018) Reference case, which changes the electricity generation mix. EIA will continue to monitor U.S. Environmental Protection Agency rulemaking and will include any final rules in subsequent AEOs.

- A number of current state and regional policies—including the Illinois Future Energy Jobs Act, the New York Clean Energy Standard, the Maryland Clean Energy Jobs Act, and the Regional Greenhouse Gas Initiative—affect the projected electric generation mix.

- Annex VI of the International Convention for the Prevention of Pollution from Ships (MARPOL Convention), which limits emissions for ocean-going ships by 2020, was updated. This update affects the projected fuel mix for maritime transport.

Significant data updates

- U.S. Geological Survey resource assessments of the Wolfcamp and Spraberry formations, released in November 2016 and May 2017, respectively, were incorporated to update crude oil and natural gas resource assumptions for the Permian basin. This change mainly affects regional oil and natural gas production and related markets.

- EIA incorporated updates to natural gas plant liquids production based on EIA surveys of natural gas processing plants.

- EIA's 2014 Manufacturing Energy Consumption Survey, released in October 2017, resulted in revisions to estimates of industrial sector energy consumption.

- Higher-resolution solar resource data were introduced to better represent the diversity of solar generation opportunities within electricity market regions.

- Cost data from the Idaho National Laboratory report, *Economic and Market Challenges Facing the U.S. Nuclear Commercial Fleet*, published in September 2016, were used to update fixed operating and maintenance cost assumptions for single-reactor nuclear plants.

Model improvements—Liquids and Natural Gas

- EIA introduced a new Natural Gas Markets Module, which now balances supply and demand on a monthly basis across states rather than on a seasonal basis across regions. The new module also better reflects changing regional natural gas flows and pricing patterns, and it includes improved representations of Canadian and Mexican natural gas markets.

- The representation of technological and operational improvements in oil and natural gas production over the projection period was revised by increasing rates of technological progress during the early development of currently undeveloped resources to reflect industry-wide identification of the most productive areas and to select the best technologies for particular geologies (i.e., learning-by-doing).

Model improvements—Electric Power

- The capability to model energy storage on the electric grid with four-hour batteries was added to more effectively model electric grid operations, including the integration of wind and solar generation.

- The capability to model two distinct solar photovoltaic (PV) technologies was added to better account for the cost and value trade-offs between fixed-tilt and tracking-solar technologies. Both technologies have achieved significant market share as PV installations have increased.

- Wind plant dispatch decisions are now evaluated at a more granular time resolution to more accurately account for time-of-day and seasonal electricity demand.

- The representation of state-level Renewable Portfolio Standards was updated to include additional policy details such as set-aside targets to more specifically account for the effect of these standards on the electric generation mix.

Model improvements—Energy Consumption

- Credit banking associated with the Zero-Emission Vehicle program in California and the nine other states that chose to adopt California's vehicle emissions standard (a subset of the Clean Air Act Section 177 states) was added to account for the effects on the sales of electric and plug-in hybrid electric vehicles early in the projection period when vehicle manufacturers use banked over-compliance credits.

- Connected and automated light-duty vehicles were added, which includes technology-induced travel demand behavior specific to those vehicles, to account for the effects on travel demand for various modes of transit.

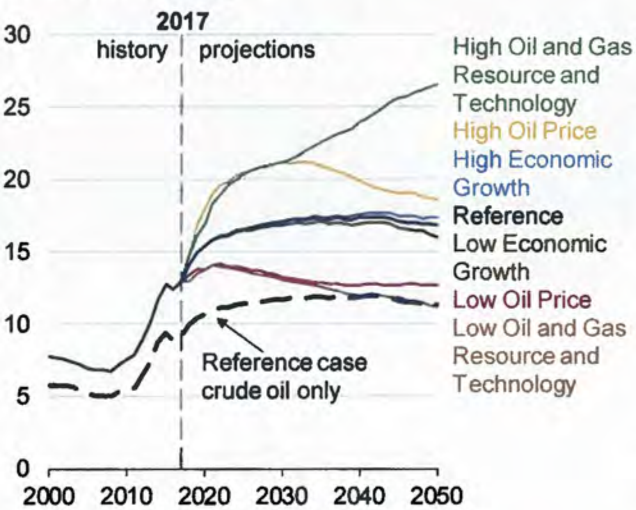
- Growth in commercial *other* electricity consumption (which includes such things as portable and plug-in devices) was indexed in AEO2018 to gross output of services, which results in slower increases in projected consumption than in AEO2017. Last year, it was indexed to expected growth in network and telecommunications equipment, which is now projected separately.

Petroleum and other liquids

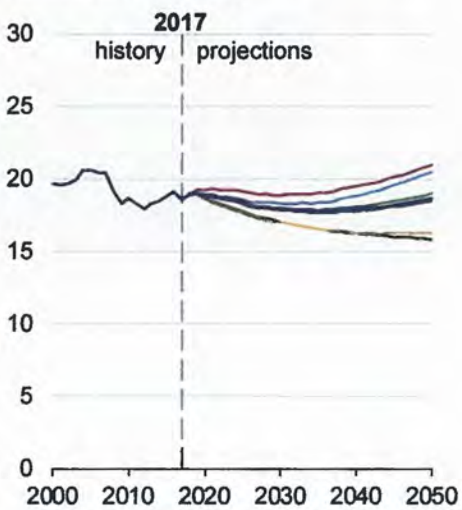
Growth in U.S. crude oil and natural gas plant liquids production generally continues through 2050 mainly as a result of the further development of tight oil resources. Over the same period, domestic consumption falls, making the United States a net exporter of liquid fuels in the Reference case and in a number of the side cases.

U.S. crude oil and natural gas plant liquids production grows to exceed its peak 1970 level—

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



Petroleum product consumption
million barrels per day



—and consumption is lower than its 2004 peak level through 2050 in most cases

- In the Reference case, U.S. crude oil production in 2018 is projected to surpass the record of 9.6 million barrels per day (b/d) set in 1970 and will continue to grow as upstream producers increase output because of the combined effects of rising prices and production cost reductions.

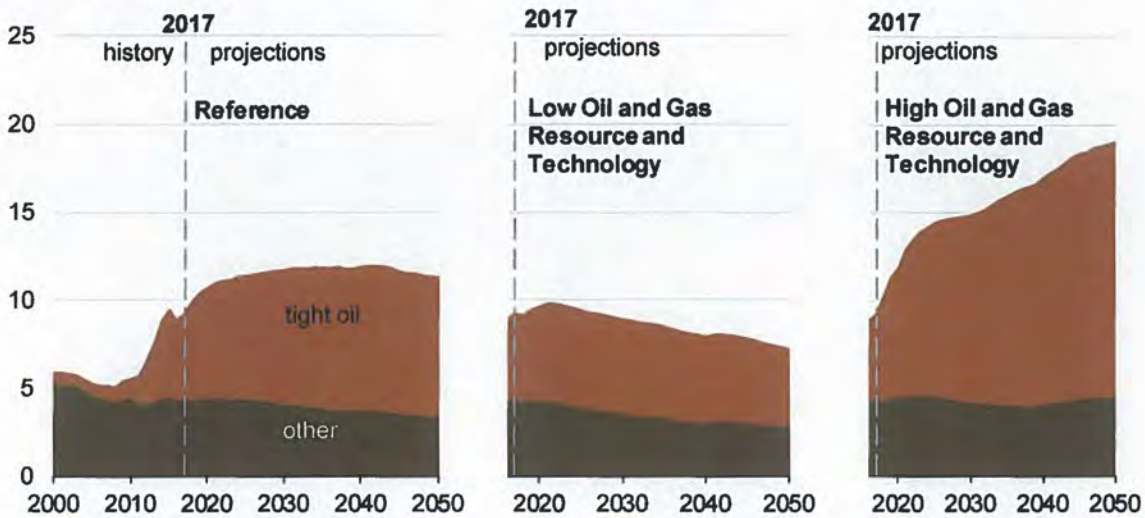
- With continued development of tight oil and shale gas resources, natural gas plant liquids production reaches 5.0 million b/d in 2023, nearly 35% above the 2017 level.

- Total liquids production varies widely under different assumptions about resources, technology, and oil prices. Production is less variable in the economic growth cases because domestic wellhead prices are less sensitive to macroeconomic growth assumptions.

- With higher levels of economic activity and relatively low oil prices, petroleum product consumption increases in the High Economic Growth and Low Oil Price cases, and it remains relatively flat or decreases in the other cases through 2050.

Tight oil production remains the leading source of U.S. crude oil production from 2017 to 2050 in the Reference case—

Crude oil production
million barrels per day

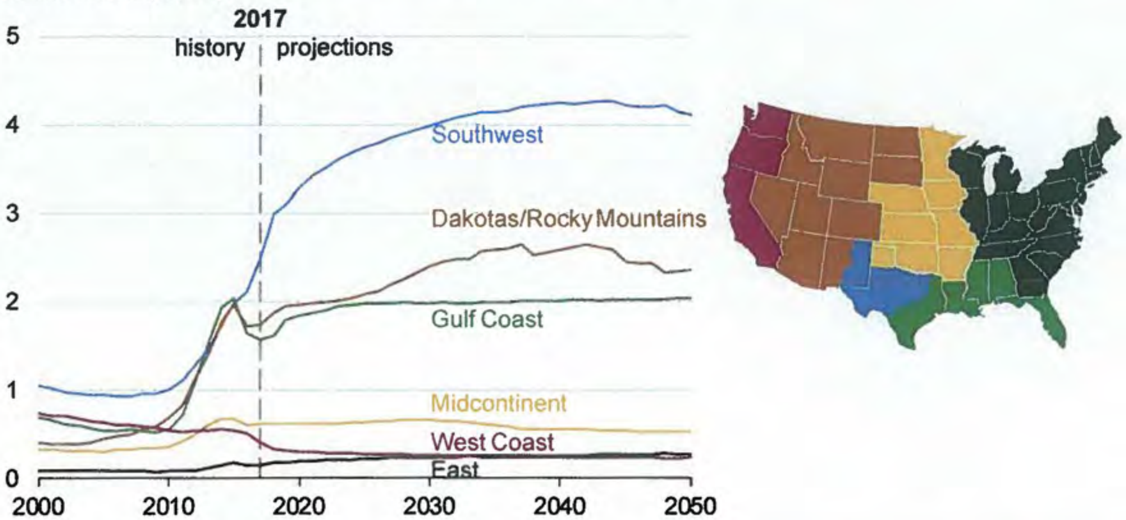


—a result that is consistent across all side cases

- Lower 48 onshore tight oil development continues to be the main driver of total U.S. crude oil production, accounting for about 65% of cumulative domestic production in the Reference case over the projection period 2017 to 2050.
- Despite rising oil prices, Reference case U.S. crude oil production levels off between 11 million and 12 million barrels per day as tight oil development moves into less productive areas and as well productivity declines.
- Previously announced deepwater discoveries in the Gulf of Mexico lead to increases in Lower 48 states offshore production through 2021. In the Reference case, offshore production then declines through 2035 and remains flat through 2050 as new discoveries offset declines in legacy fields.

The Southwest region leads growth in U.S. tight oil production in the Reference case—

Lower 48 onshore crude oil production by region (Reference case)
million barrels per day

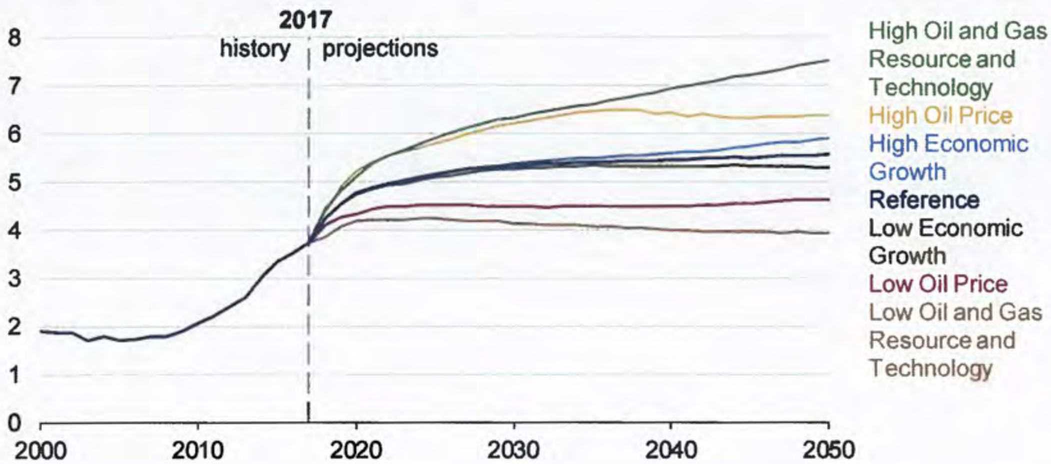


—but the Gulf Coast and Dakotas/Rocky Mountains regions also remain important contributors to overall production

- Growth in Lower 48 onshore crude oil production occurs mainly in the Permian basin in the Southwest region. This basin includes many prolific tight oil plays with multiple layers, including Bone Spring, Spraberry, and Wolfcamp, making it one of the lower-cost areas to develop.
- Production growth in the Dakotas/Rocky Mountains region is driven by increases in production from the Bakken and Niobrara tight oil plays.
- Production in the Gulf Coast region increases through 2025 before flattening out as drilling in the Eagle Ford becomes less productive.

Natural gas plant liquids production increases from 2017 levels in all *Annual Energy Outlook* cases—

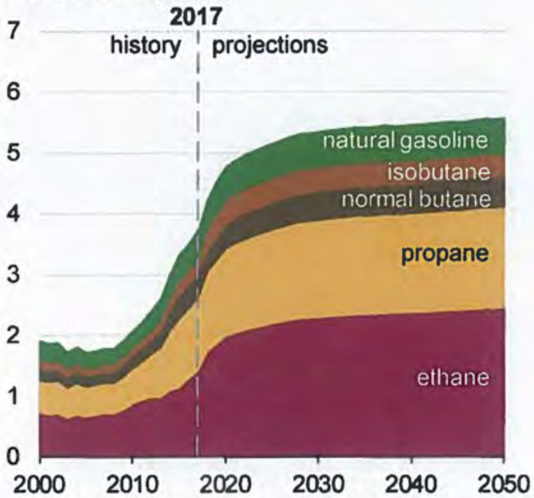
U.S. natural gas plant liquids production
million barrels per day

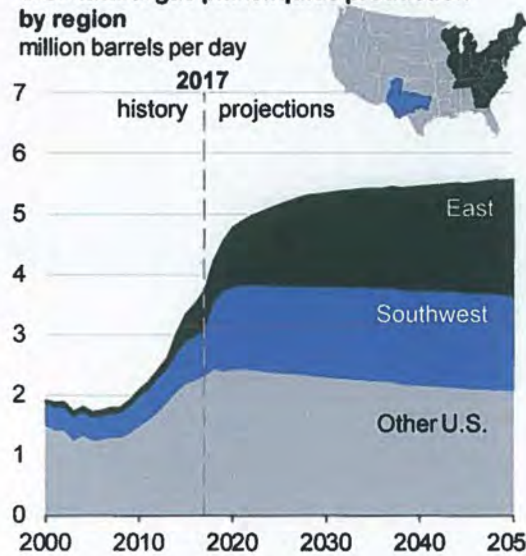


—driven by the higher price of oil relative to natural gas, liquids-rich natural gas formations, and growth in ethane demand

- In the Reference case, natural gas plant liquids (NGPL) production nearly doubles between 2017 and 2050, supported by an increase in global petrochemical industry demand.
- Most NGPL production growth in the Reference case occurs before 2025 when increased demand spurs higher ethane recovery and producers focus on natural gas liquids-rich plays, where NGPL-to-gas ratios are highest. After 2025, production migrates to areas where this ratio is lower.
- NGPL production is projected to double in the High Oil and Gas Resource and Technology case and to remain nearly flat in the Low Oil and Gas Resource and the Technology case as a result of alternate resource and technology assumptions.

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





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

- Natural gas plant liquids (NGPL) are used in many different ways. Ethane is used almost exclusively for petrochemicals, while approximately 40% of propane is used for petrochemicals, and the remainder is used for heating, grain drying, and transportation. Approximately 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.

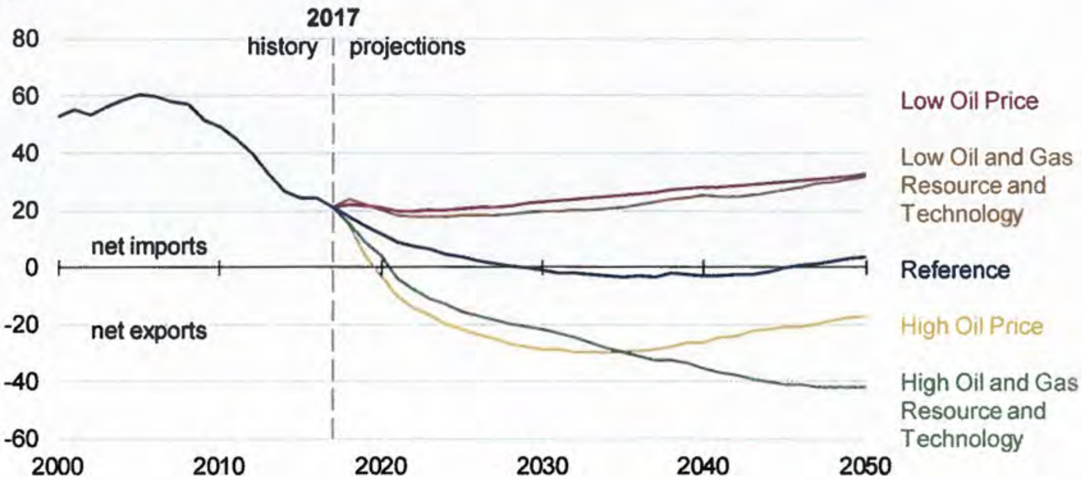
- The shares of NGPL components in the Reference case are relatively stable over the entire projection period, with ethane and propane contributing about 44% and 30%, respectively, to the total volume.

- The large increase in NGPL production in the East (Marcellus and Utica plays) and Southwest (Permian plays) over the next 10 years is explained mainly by its close association with the development of crude oil and natural gas resources in those regions.

- By 2050, the East and Southwest regions account for more than 60% of total U.S. NGPL production.

In the Reference case, the United States is a modest net exporter of petroleum on a volume basis from 2029 to 2045—

Petroleum net imports/exports as a percentage of product supplied
percent



—but side case results vary significantly using different assumptions

- Net imports of crude oil and liquid fuels are projected to fall between 2017 and 2035 in the Reference case as strong production growth and decreasing domestic demand push the United States to net exporter status.

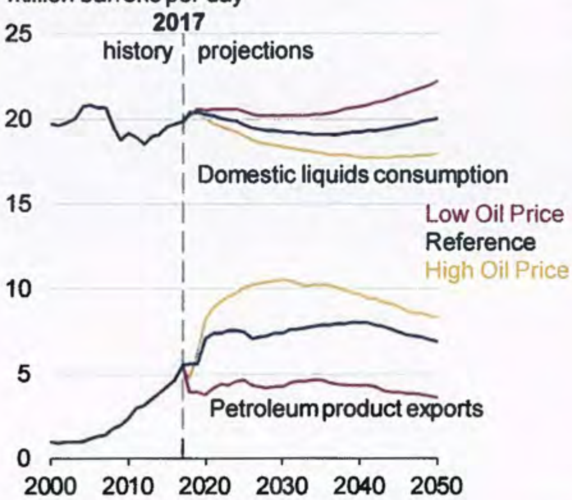
- In the Reference case, net exports from the United States as a percentage of product supplied (a proxy for domestic consumption) is projected to peak at more than 3% in 2037, before gradually reversing as domestic consumption rises. The United States returns to being a net petroleum importer in 2045 on a volume basis.

- Changes in net imports are larger across different price and resource scenarios as domestic crude oil production shifts. Net exports as a percentage of product supplied reaches a high of 30% in 2034 in the High Oil Price case. Conversely, low oil prices in the Low Oil Price case drive the net import share of product supplied up from 21% in 2017 to 32% in 2050.

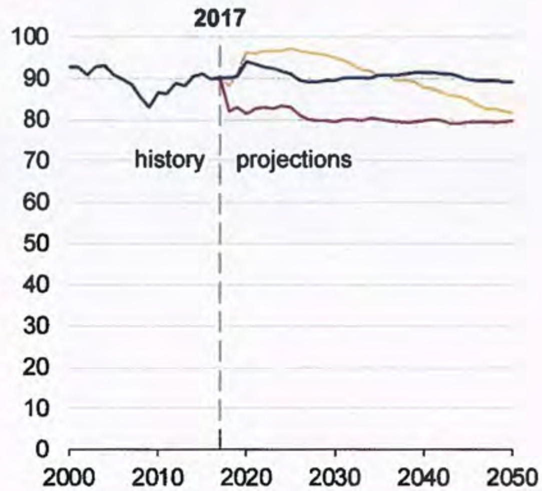
- The export share of petroleum product supplied continues to grow in the High Oil and Gas Resource and Technology case, reaching 42% by 2050.

In the Reference case, petroleum product exports increase as domestic consumption decreases—

U.S. liquids consumption and petroleum product exports
million barrerls per day



U.S. refinery utilization
percent



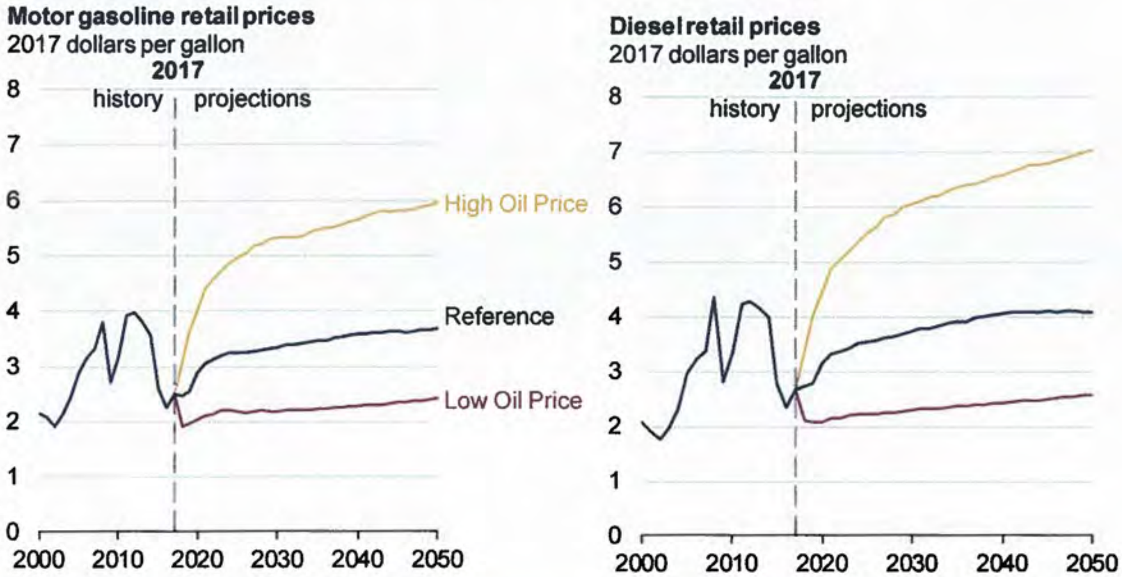
— and refinery utilization rates remain relatively stable

- In the Reference case, domestic consumption of petroleum products generally decreases through 2035, mainly because of vehicle fuel efficiency gains, and petroleum product exports generally increase through 2040. Domestic liquids consumption and petroleum product exports are two of the main drivers for refinery utilization both historically and through the projection period.

- In the Low Oil Price case, lower global demand for petroleum products leads to lower levels of petroleum product exports and refinery utilization in the United States. Refinery utilization stays relatively stable at slightly below 80% through most of the projection period.

- In the early years of the projection, the elevated international demand in the High Oil Price case leads to higher U.S. petroleum product exports and, initially, higher U.S refinery utilization. Refinery utilization drops gradually as U.S. domestic consumption declines in response to high oil prices.

In the Reference case, motor gasoline and diesel fuel prices rise after 2018 through the projection period—



—but neither price returns to its previous peak

- Retail prices of motor gasoline and diesel fuel are projected to increase from 2018 to 2050 in the Reference case, largely because of expected increases in crude oil prices.

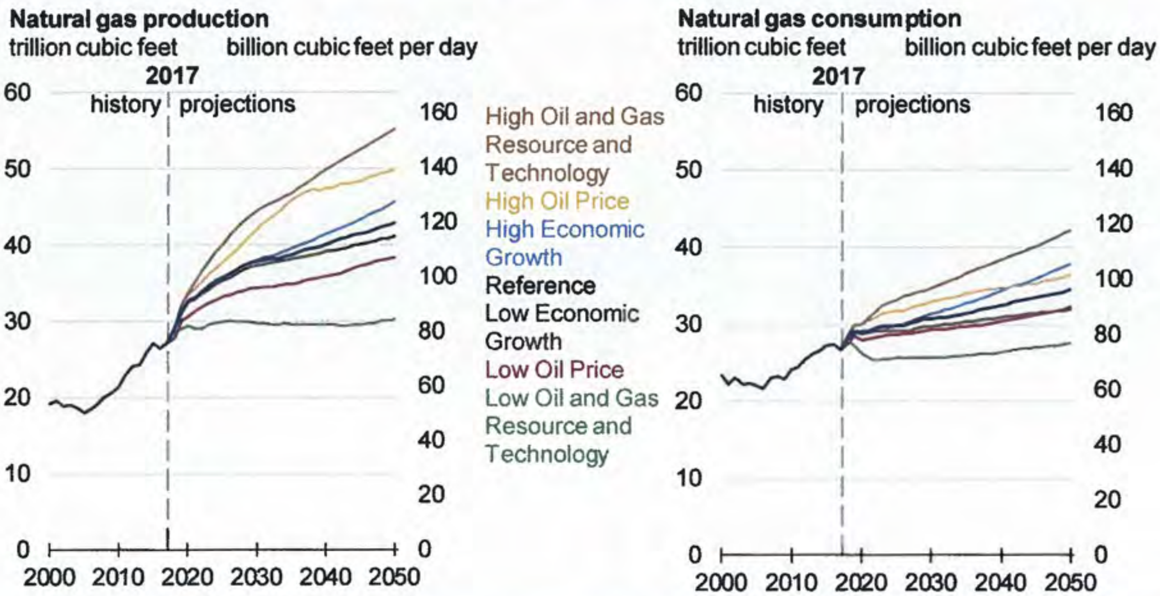
- Although the spread between diesel fuel and motor gasoline retail prices has tightened on a volume basis in recent years, this trend reverses through 2041 because of strong growth in global diesel demand for use in transportation and industry.

- Motor gasoline and diesel fuel retail prices move in the same direction as crude oil prices in the High and Low Oil Price cases. Motor gasoline retail prices in 2050 range from $5.95 per gallon (gal) in the High Oil Price case to $2.41/gal in the Low Oil Price case. Diesel fuel retail prices range from $7.02/gal in the High Oil Price case to $2.56/gal in the Low Oil Price case in 2050.

Natural gas

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

U.S. natural gas consumption and production increase in all cases—



—with production growth outpacing natural gas consumption in all cases

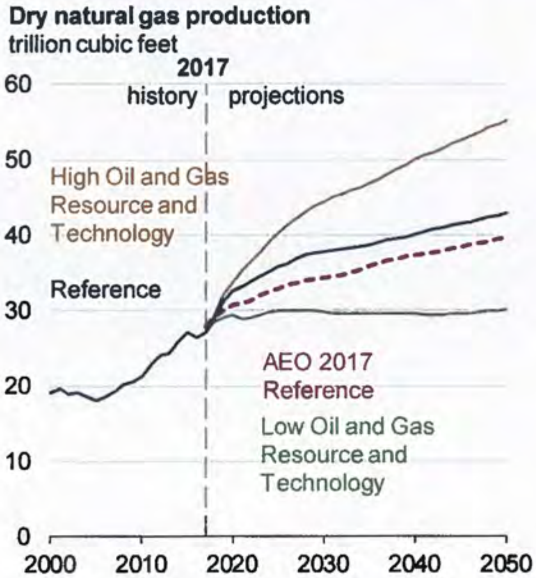
- Natural gas production in the Reference case grows 6%/year from 2017 to 2020, which is greater than the 4%/year average growth rate from 2005 to 2015. However, after 2020, it slows to less than 1%/year for the remainder of the projection.

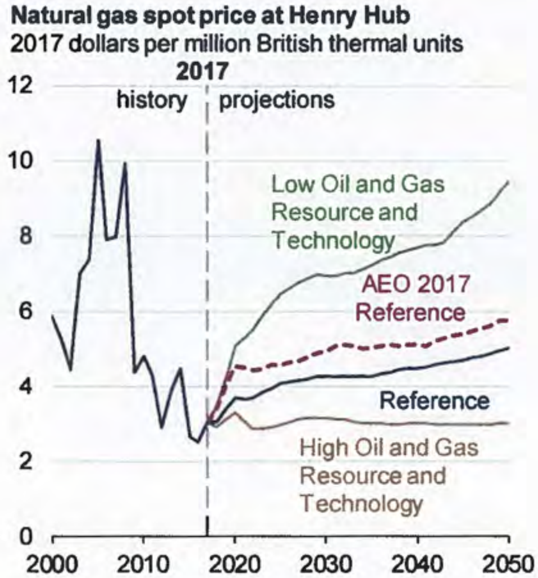
- Near-term production growth across all cases is supported by growing demand from large natural gas-intensive, capital-intensive chemical projects and from the development of liquefaction export terminals in an environment of low natural gas prices.

- After 2020, production grows at a higher rate than consumption in all cases except in the Low Oil and Gas Resource and Technology case, where production and consumption remain relatively flat as a result of higher production costs.

- In all cases other than the Low Oil and Gas Resource and Technology case, U.S. natural gas consumption increases over the entire projection period.

Natural gas prices across cases are dependent on resource and technology assumptions—

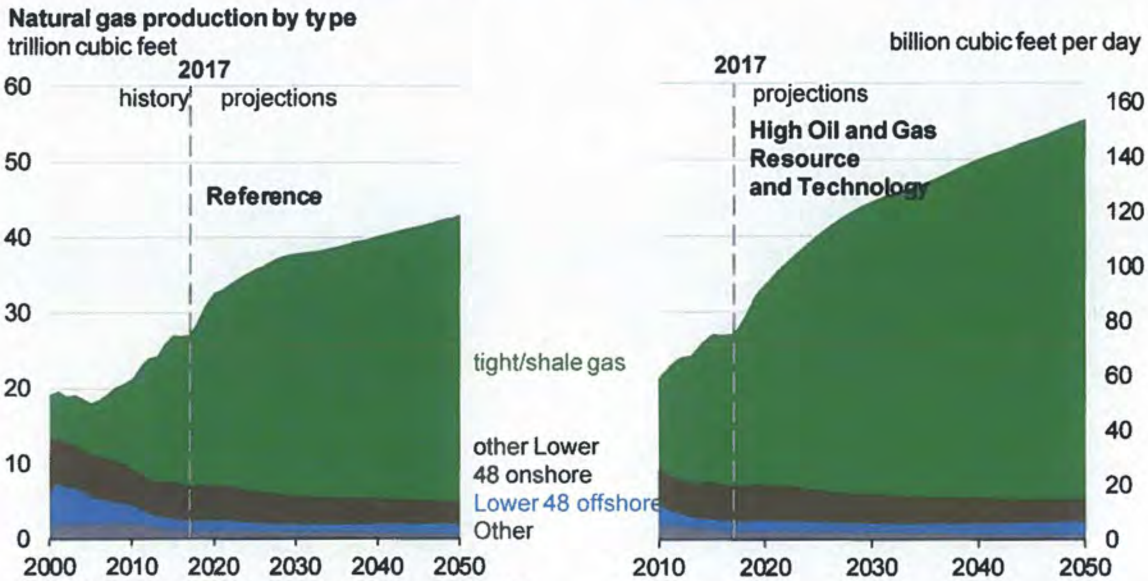




—and Henry Hub prices in the AEO2018 Reference case are 14% lower on average through 2050 than in AEO2017

- Growing demand in domestic and export markets leads to increasing natural gas spot prices over the projection period at the U.S. benchmark Henry Hub in the Reference case despite continued technological advances that support increased production.
- To satisfy the growing demand for natural gas, production must expand into less prolific and more expensive-to-produce areas, which will put upward pressure on production costs.
- The High Oil and Gas Resource and Technology case, which reflects lower costs and higher resource availability, shows an increase in production and lower prices relative to the Reference case. In the Low Oil and Gas Resource and Technology case, high prices, which result from higher costs and fewer available resources, result in lower domestic consumption and lower exports over the projection period.
- Natural gas prices in the AEO2018 Reference case are lower than in the AEO2017 Reference case because of an estimated increase in lower-cost resources, primarily in the Permian and Appalachian basins, which support higher production levels at lower prices over the projection period.

Increased U.S. natural gas production is the result of continued development of shale gas and tight oil plays—

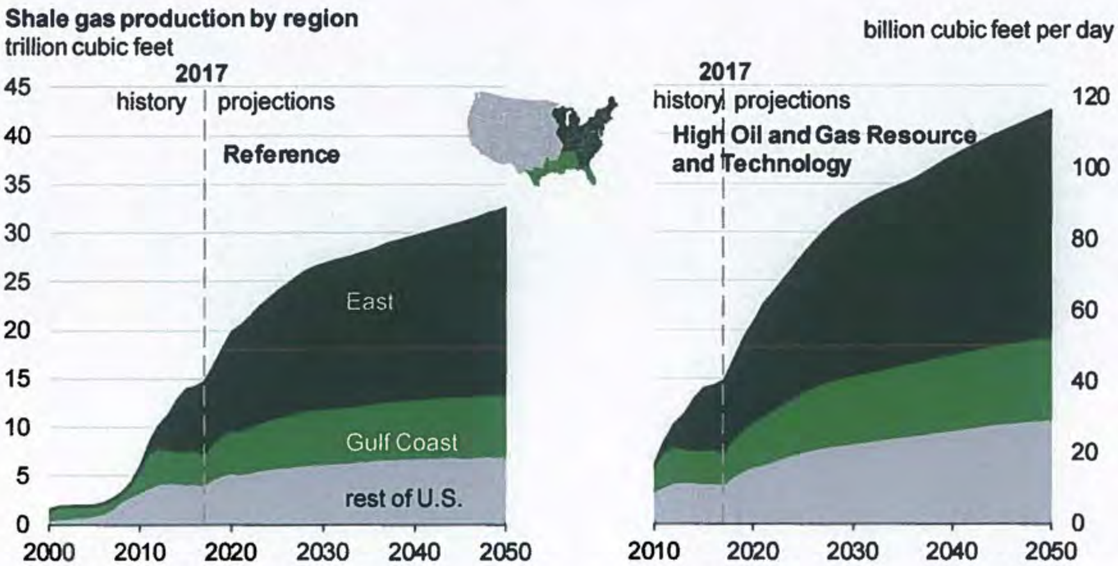


Note: Other includes Alaska and coalbed methane

—which account for more than three-quarters of natural gas production by 2050

- Natural gas production from shale gas and tight oil plays as a share of total U.S. natural gas production is projected to continue to grow in both share and absolute volume because of the large size of the associated resources, which extend over more than 500,000 square miles.
- Offshore natural gas production in the United States stays nearly flat over the projection period as production from new discoveries generally offsets declines in legacy fields.
- Production of coalbed methane gas generally continues to decline through 2050 because of unfavorable economic conditions for producing that resource.

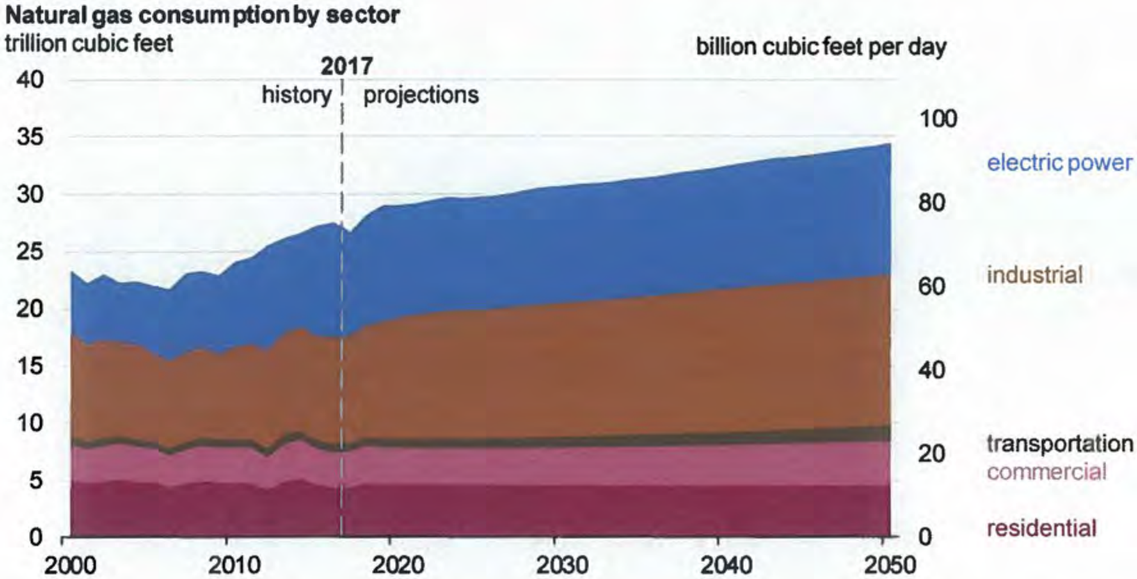
Plays in the East lead production of U.S. natural gas from shale resources in the Reference case—



—followed by growth in Gulf Coast onshore production

- Continued development of the Marcellus and Utica plays in the East is the main driver of growth in total U.S. shale gas production across most cases and the main source of total U.S. dry natural gas production.
- Production from the Eagle Ford and Haynesville plays in the Gulf Coast region is a secondary source to domestic dry natural gas, with production largely leveling off after 2028.
- Associated natural gas production from tight oil production in the Permian basin grows strongly through the projection period.
- Continued technological advancements and improvements in industry practices are expected to lower costs and to 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 (Marcellus, Utica, and Haynesville).

Industrial and electric power demand drives natural gas consumption growth—



—as consumption in the residential and commercial sectors remains relatively flat over the projection period in the Reference case

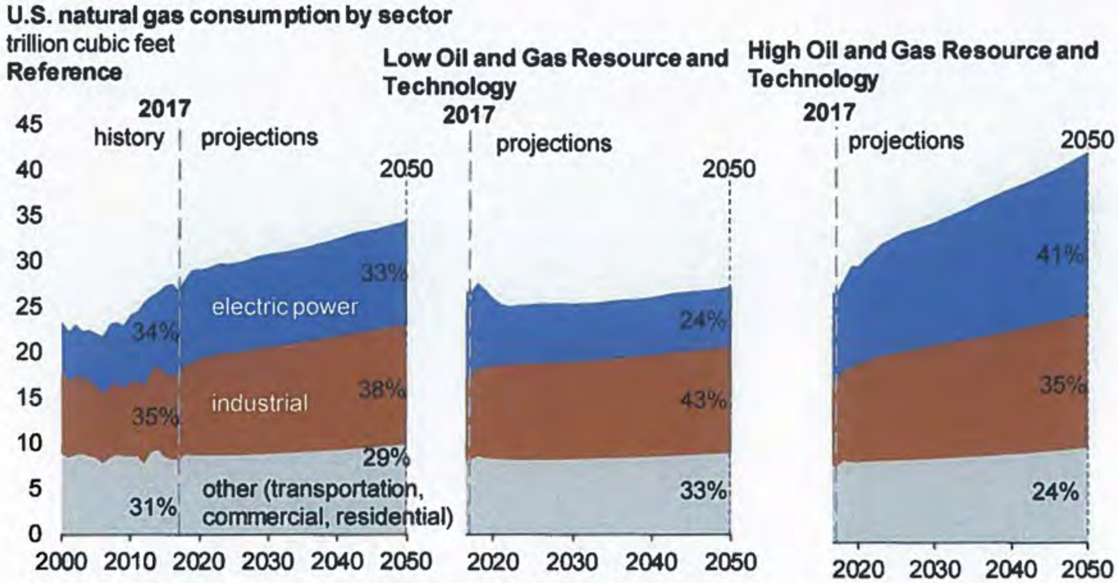
- The industrial sector is the largest consumer of natural gas in the Reference case. Major natural gas consumers in this sector include the chemical industry (where natural gas is used as a feedstock in the production of methanol and ammonia), industrial heat and power, and liquefied natural gas export facilities.

- Natural gas used for electric power generation generally increases over the projection period but at a slower rate than in the industrial sector. This growth is supported by the scheduled expiration of renewable tax credits in the mid-2020s.

- Natural gas consumption in the residential and commercial sectors remains largely flat because of efficiency gains and population shifts that counterbalance demand growth.

- Although natural gas use rises in the transportation sector, particularly for freight and marine shipping, it remains a small share of total natural gas consumption, and natural gas remains a small share of transportation fuel demand.

Natural gas supply assumptions that affect prices result in significant changes in natural gas consumption—



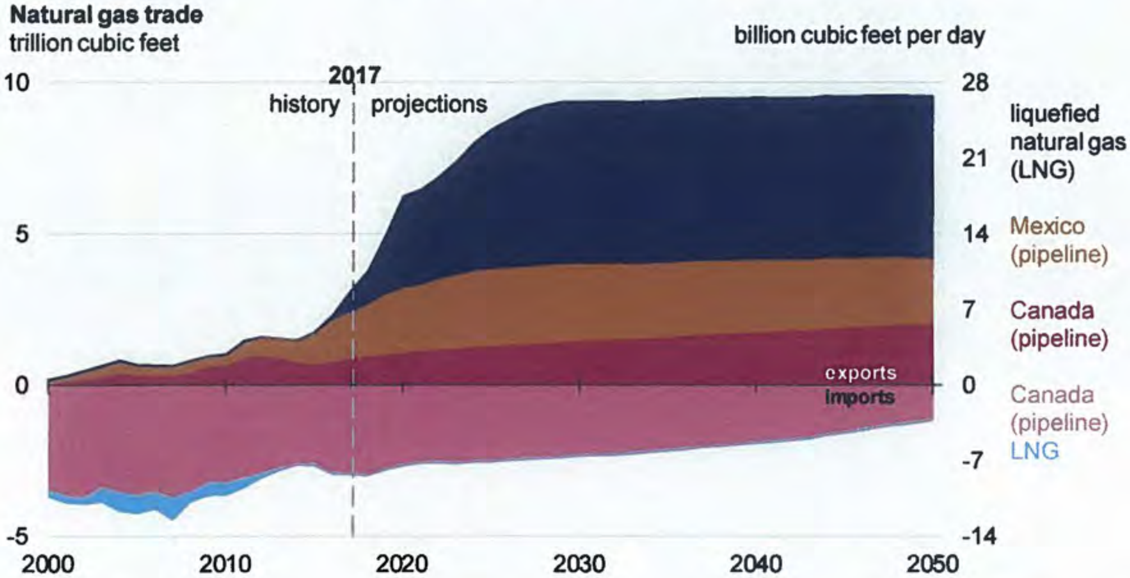
—particularly in the electric power sector as natural gas prices across cases change its competitiveness with other generation fuels

- Between the two largest sectors of natural gas consumption—industrial and electric power—the electric power sector is more responsive to prices. In the short term, electric generators can react quickly to take advantage of changes in relative fuel costs and generally have more fuel options than the industrial sector. In contrast, although energy costs are considered when making long-term decisions about the number, siting, and types of industrial facilities, these costs are only one of many factors.

- The industrial sector is projected to be the largest natural gas-consuming sector in the Reference case, accounting for 38% of the domestic market in 2050. However, in the High Oil and Gas Resource and Technology case, the electric power sector is the largest natural gas consumer. Because Henry Hub spot prices remain lower than $3.50 per million British thermal units (MMBtu) in that case through the entire projection period, natural gas is more competitive with renewables and coal. By 2050, natural gas use in the electric power sector is 41% of total U.S. domestic natural gas consumption in that case.

- Conversely, in the Low Oil and Gas Resource and Technology case, the electric power sector only accounts for an average 25% of U.S. natural gas use from 2020 to 2050 because of higher natural gas prices—Henry Hub natural gas prices reach $6.50/MMBtu by 2025 and more than $9.40/MMBtu by 2050. The industrial sector accounts for 42% of the domestic natural gas market from 2020–2050 in that case.

The United States is a net natural gas exporter in the Reference case because of near-term export growth and continued import decline —



—as liquefied natural gas export facilities allow domestic production to reach global markets

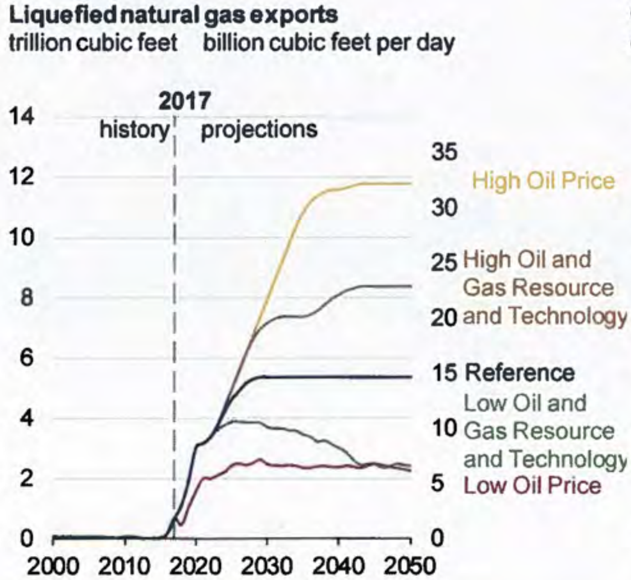
- In the Reference case, pipeline exports to Mexico and liquefied natural gas (LNG) exports increase until 2020. Through 2030, pipeline export growth to Mexico slows, and LNG exports grow rapidly.

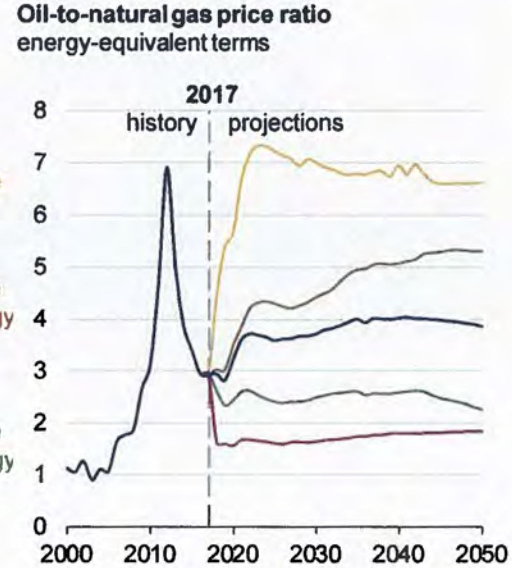
- Increasing natural gas exports to Mexico are the result of more pipeline infrastructure to and within that country, allowing for increased natural gas-fired power generation. By the mid-2020s, Mexican domestic natural gas production begins to displace U.S. exports.

- One LNG export facility currently operates in the Lower 48 states with a second facility expected to be operating in March 2018. After the five U.S. LNG export facilities currently under construction are completed by 2021, LNG export capacity is projected to increase as Asian demand grows and U.S. natural gas prices remain competitive. As U.S.-sourced LNG becomes less competitive, export volumes remain constant during the later years of the projection.

- U.S. imports of natural gas from Canada, primarily from its prolific Western region, remain relatively stable for the next few years before declining from historically high 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.

U.S. liquefied natural gas exports are sensitive to both oil and natural gas prices—





—resulting in a wide range of expected U.S. liquefied natural gas export levels across cases

- Historically, most liquefied natural gas (LNG) was traded under long-term, oil price-linked contracts, in part because oil could substitute for natural gas in industry and for power generation. However, as the LNG market expands, contracts are expected to change with weaker ties to oil prices.

- When the oil-to-natural gas price ratio is highest, as in the High Oil Price case, U.S. LNG exports are at their highest levels. Demand for LNG increases as consumers move away from petroleum products. U.S. LNG supplies have the advantage of being priced based on relatively low domestic spot prices instead of on oil-linked contracts.

- In the High Oil and Gas Resource and Technology 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 Resource and Technology case result in lower U.S. LNG exports.

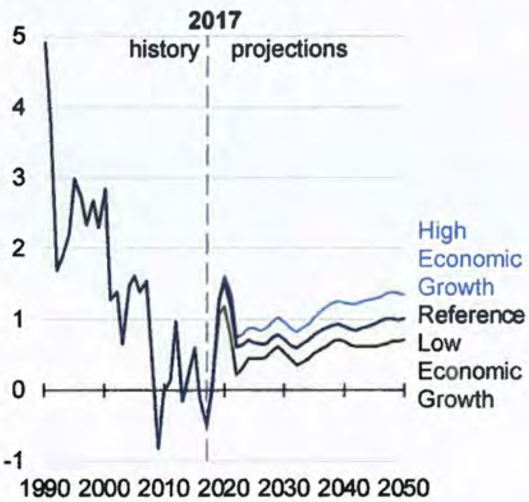
- As more natural gas is traded via short-term contracts or traded on the spot market, the link between LNG and oil prices is projected to weaken over time, making U.S. LNG exports less sensitive to the oil-to-natural gas price ratio and resulting in slower growth in U.S. LNG exports in all cases.

Electricity

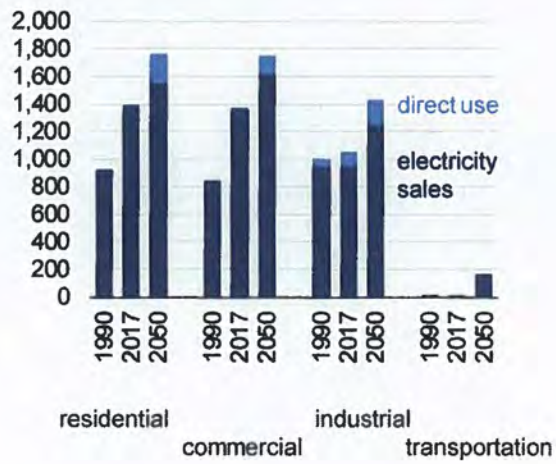
As electricity demand grows modestly, the primary drivers for new capacity in the Reference case are the retirements of older, less-efficient fossil fuel units, the near-term availability of renewable energy tax credits, and the continued decline in the capital cost of renewables, especially solar photovoltaic.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

After decades of slowing growth, electricity use is expected to grow steadily through 2050—

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



Electricity use by end-use demand sector
billion kilowatthours

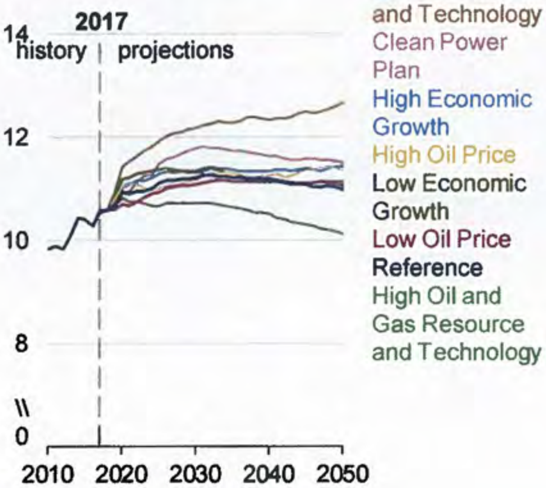


—with growth projected in all demand sectors

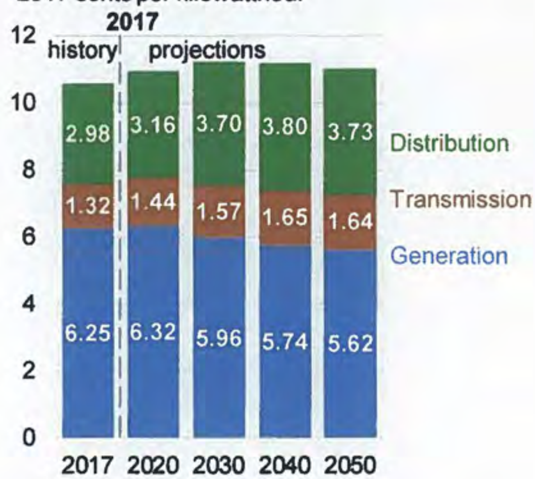
- Electricity demand is driven by economic growth and increasing efficiency. Historical electricity demand growth rates slowed as older, less-efficient end-use equipment was replaced with newer, more-efficient stock even as the economy continued to grow.
- Electricity demand growth was negative in 2017, but it is projected to rise slowly through 2050. From 2017–2050, the average annual growth in electricity demand reaches about 0.9% in the AEO2018 Reference case.
- Through the projection period, the average electricity growth rates in the High and Low Economic Growth cases deviate from the Reference case the most—where the High Economic Growth case is about 0.3 percentage points higher than in the Reference case, and electricity growth in the Low Economic Growth case is about 0.3 percentage points lower than in the Reference case.
- Growth in direct-use generation outpaces the growth in retail sales as a result of the adoption of rooftop photovoltaic and natural gas-fired combined heat and power.

Reference case electricity prices remain flat, with falling generation costs offset by increasing transmission and distribution costs—

Average electricity price
2017 cents per kilowatthour



Electricity prices by service category (Reference case)
2017 cents per kilowatthour



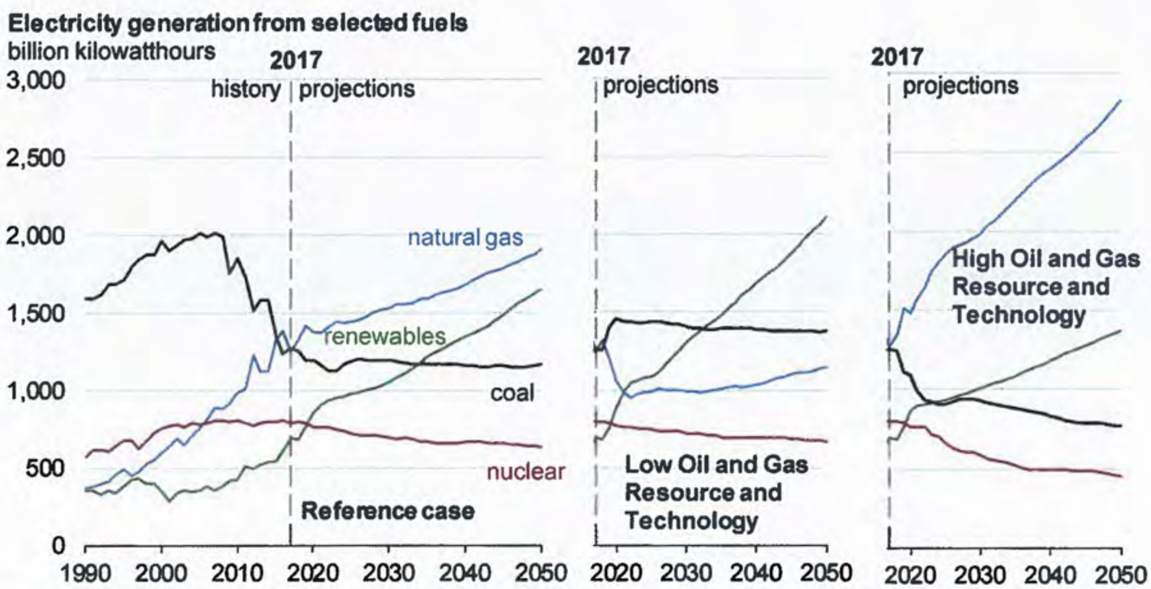
—with significant price differences through 2050 across scenarios depending on natural gas prices

- Average electricity prices are projected to remain relatively flat—ranging between 10.6 and 11.8 cents per kilowatthour (kWh)—through the projection period in the Reference case and the side cases (except for the Low and High Oil and Gas Resource and Technology cases). By 2050, prices rise to 12.7 cents/kWh in the Low Oil and Gas Resource and Technology case and fall to 10.1 cents/kWh in the High Oil and Gas Resource and Technology case.

- The generation cost represents the largest share of the price of electricity, and it is projected to decrease by 10% from 2017 to 2050 in the Reference case in response to continued low natural gas prices and increased generation from renewables.

- The transmission cost component is projected to increase by 24% over the forecast period, and the distribution cost component is expected to increase by 25%—reflecting the need to replace aging infrastructure and upgrade the grid to accommodate changing reliability standards.

The projected mix of electricity generation technologies varies widely across cases—

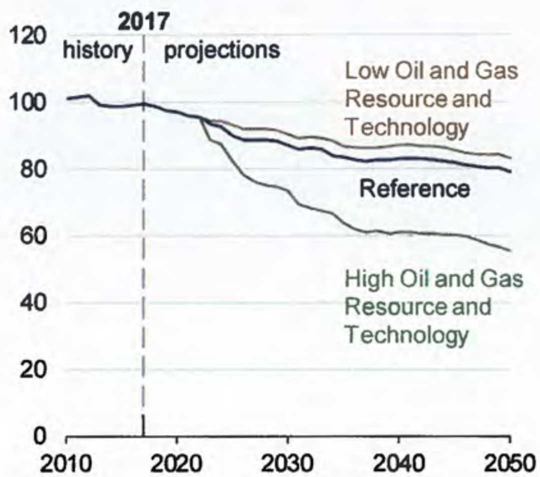


—as differences in fuel prices result in significant substitution

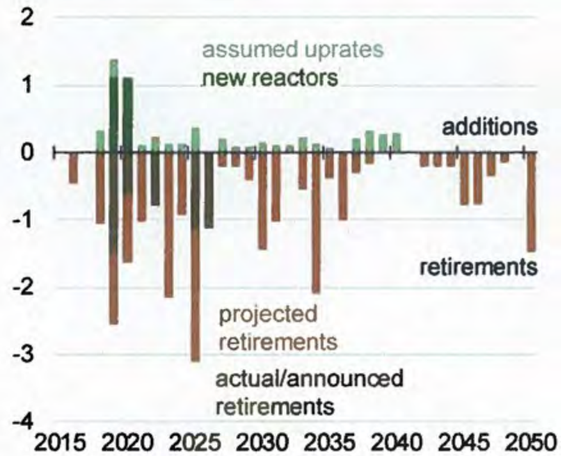
- Fuel prices in the near term drive the share of natural gas-fired and coal-fired generation. In the longer term, the relatively low cost of coal moderates the decline in coal-fired generation in the Reference case.
- Federal tax credits drive near-term growth in renewables generation, moderating growth in natural gas-fired electricity generation except with in the High Oil and Gas Resource and Technology case, which projects very low natural gas prices.
- Lower natural gas prices in the High Oil and Gas Resource and Technology case support significantly higher natural gas-fired generation, with less growth in renewables generation than in the Reference case and declining coal-fired generation from 2017 through 2050.
- Higher natural gas prices in the Low Oil and Gas Resource and Technology case lead to higher levels of coal-fired generation compared with the Reference case, with 460 billion kilowatthours more renewables generation in 2050 than in the Reference case.

Nuclear capacity retires as natural gas prices decrease—

Nuclear electricity generating capacity
gigawatts



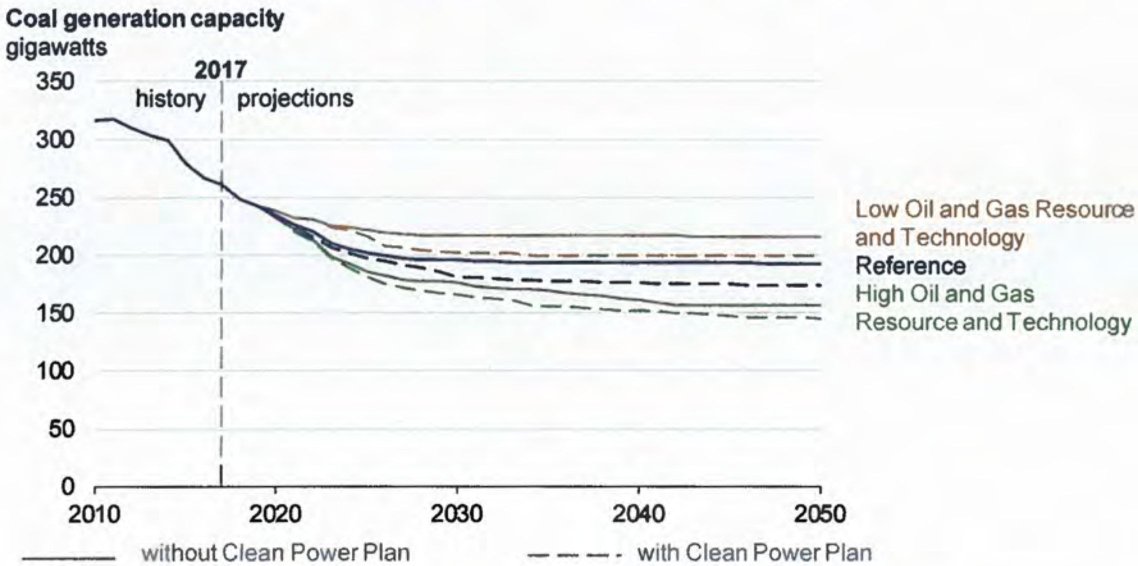
Year-over-year nuclear capacity changes (Reference case)
gigawatts



—because of lower revenues in competitive power markets

- The Reference case projects a steady decline in nuclear electric generating capacity—from 99 gigawatts (GW) in 2017 to 79 GW in 2050 (a 20% decline)—with no new plant additions beyond 2020.
- Lower natural gas prices in the High Oil and Gas Resource and Technology case lead to lower wholesale power market revenues for nuclear power plant operators, accelerating the closure of an additional 24 GW of nuclear capacity by 2050 compared with the level in the Reference case.
- Higher natural gas prices in the Low Oil and Gas Resource and Technology case decrease the financial risks to nuclear power plant operators, resulting in fewer retirements of nuclear capacity (4 GW) through 2050 compared with the Reference case.

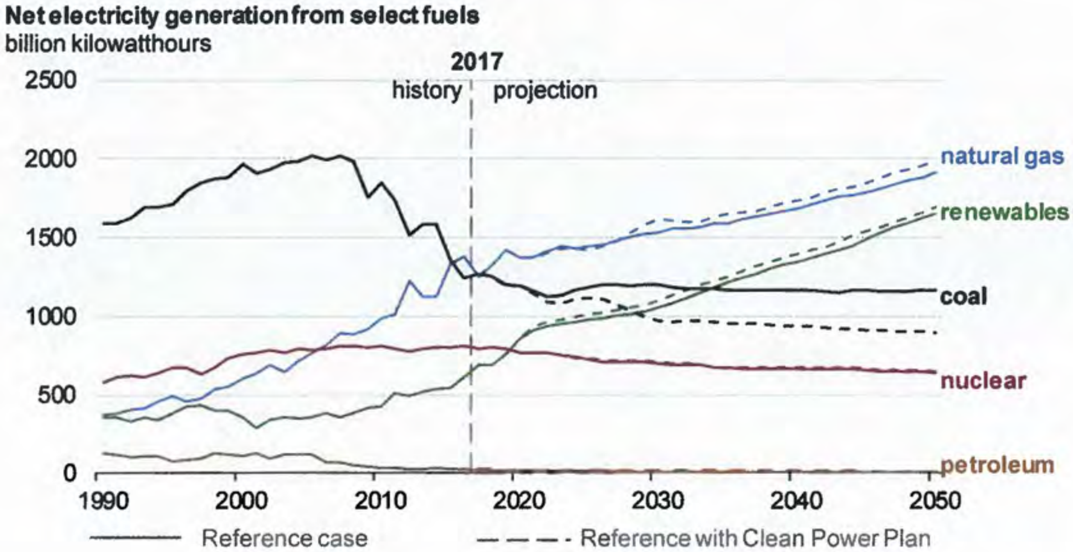
Coal-fired electric generating capacity decreases through 2030, even without the Clean Power Plan or lower natural gas prices—



—while lower natural gas prices would result in additional reductions in projected coal-fired electric generating capacity

- Between 2011 and 2016, net coal capacity decreased by nearly 60 gigawatts (GW), partly as a result of compliance with the U.S. Environmental Protection Agency's Mercury and Air Toxics Standards.
- Coal-fired generating capacity decreases by an additional 65 GW between 2017 and 2030 as a result of competitively priced natural gas and increasing renewables generation, before leveling off near 190 GW in the Reference case through 2050.
- Higher natural gas prices in the Low Oil and Gas Resource and Technology case slow the pace of coal power plant retirements by approximately 20 GW in 2030 versus the Reference case. Conversely, lower natural gas prices in the High Oil and Gas Resource and Technology case increase coal power plant retirements by 19 GW in 2030, with 157 GW of coal capacity remaining by 2050.
- Adoption of the Clean Power Plan or similar greenhouse gas emission restrictions by regional or state authorities results in 15 GW of additional coal power plant retirements by 2030 and 19 GW by 2050 in the Reference case.

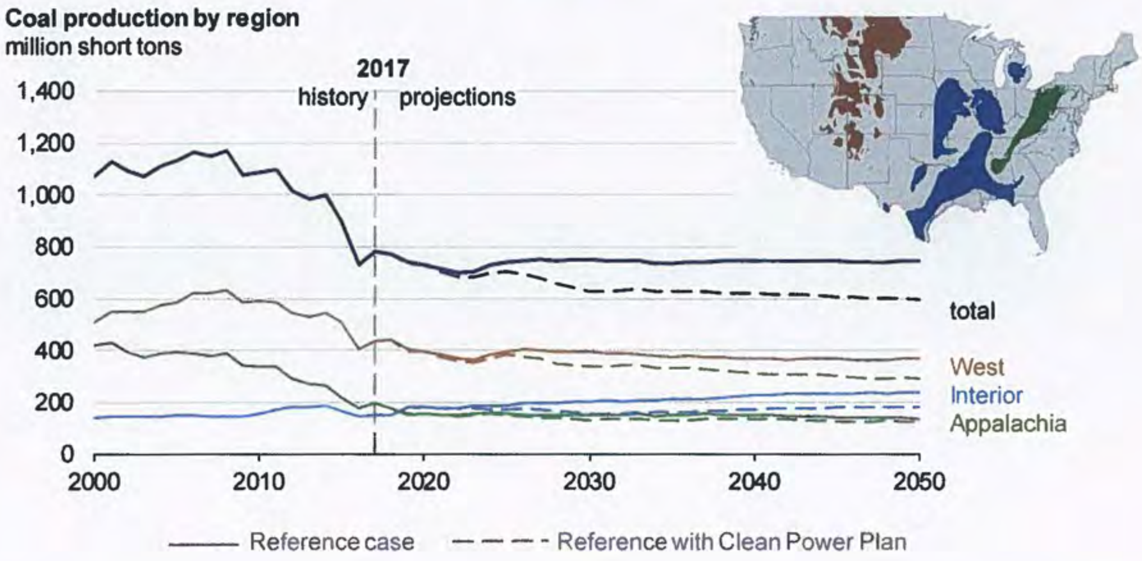
Coal-fired electricity generation remains at a higher level in the Reference case than in the Clean Power Plan case—



—but growth in natural gas and renewables generation capacity dampens coal's growth

- In the Reference case, near-term coal power plant retirements and competition with natural gas-fired electricity generation result in a slight decline in coal-fired generation through 2022 before stabilizing at about 1,200 billion kilowatthours (BkWh) through 2050. In the Clean Power Plan (CPP) case, coal-fired electricity generation continues to decline through 2030 to about 1,000 BkWh, then declines very gradually through 2050.
- Natural gas-fired generation steadily increases its market share of total electricity generation relative to coal through 2050, and it grows at about the same rate in the Reference and CPP cases.
- Federal tax credits lead to a significant increase in renewable electricity generation through the early 2020s in both the Reference and CPP cases. Continued favorable economics relative to other generating technologies result in a more than doubling of renewables generation between 2017 and 2050, with an average annual growth rate of 2.8% in both the Reference case and the CPP case.

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

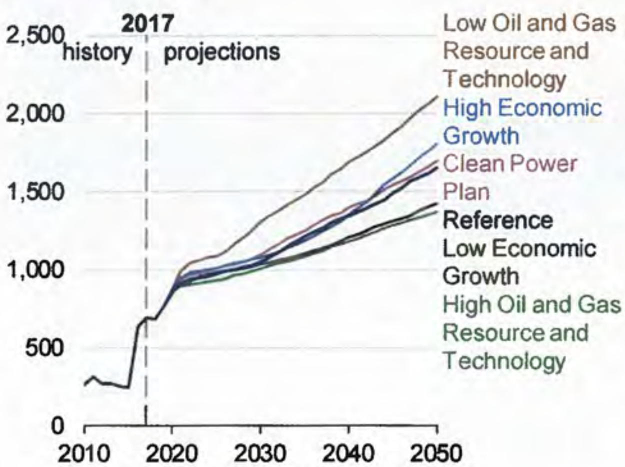


—before stabilizing as natural gas prices increase through 2050

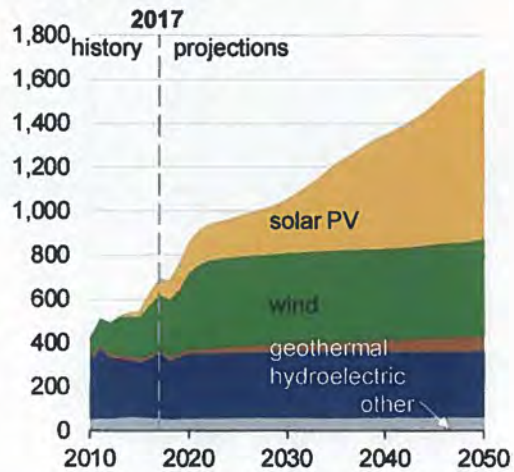
- Coal production in the Reference case continues to decline, from 784 million short tons (MMst) in 2017 to 699 MMst in 2022, in response to retirements of coal-fired electric power plants and competitive price pressure from natural gas and renewables.
- In the Reference case, coal production rises slightly in the mid-2020s, rising to 750 MMst in 2030 before decreasing slightly as natural gas prices increase and as renewable capacity additions slow with the expiration of the production tax credit for wind installations.
- In the Reference case, coal production in the Interior region grows by about 90 MMst between 2017 and 2050, while production in the Appalachia and the West regions declines by 58 MMst and 69 MMst, respectively, in part as a result of expected improvements in labor productivity for the Interior region compared with gradual declines in other regions.
- Under the Clean Power Plan, coal production is projected to decrease to 629 MMst by 2030 and to decline gradually thereafter.

Generation from renewable sources grows across all cases, led by growth in wind and solar photovoltaic generation—

Total renewables generation, including end-use generation
billion kilowatthours



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

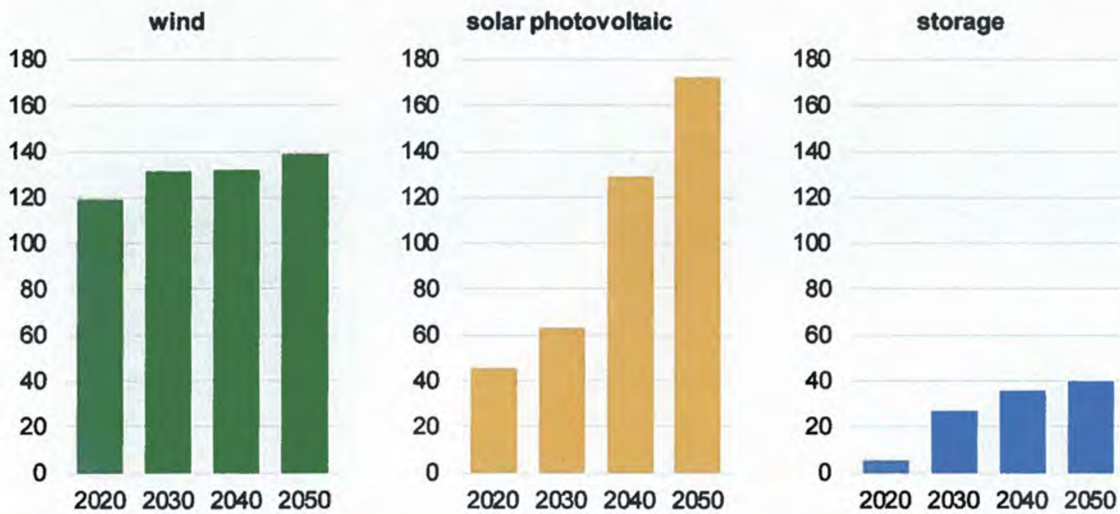


—even in cases with relatively low electricity demand or low natural gas prices

- In the Reference case, renewable generation is projected to increase 139% through the end of the projection period, reaching 1,650 billion kilowatthours (BkWh) by 2050.
- The increase in wind and solar generation leads the growth in renewable generation through the projection period, accounting for nearly 900 BkWh (94%) of the total growth in the Reference case. The extended tax credits account for much of the accelerated growth in the near term. Solar photovoltaic (PV) growth continues through the projection period as solar PV costs continue to decrease.
- In the High Oil and Gas Resource and Technology case, low natural gas prices limit the growth of renewables in favor of additional natural gas-fired generation. Renewables generation is 277 BkWh lower than Reference case levels in 2050, although this level still represents a near doubling from 2017 levels.
- In the Low Economic Growth case, electricity demand is lower than in the Reference case. Because renewables are a marginal source of new generation, this lower level of demand results in 228 BkWh less renewable generation in 2050 compared with the Reference case.

Increasing wind and solar capacity additions in the Reference case—

Utility-scale wind, solar, and storage operating capacity
gigawatts

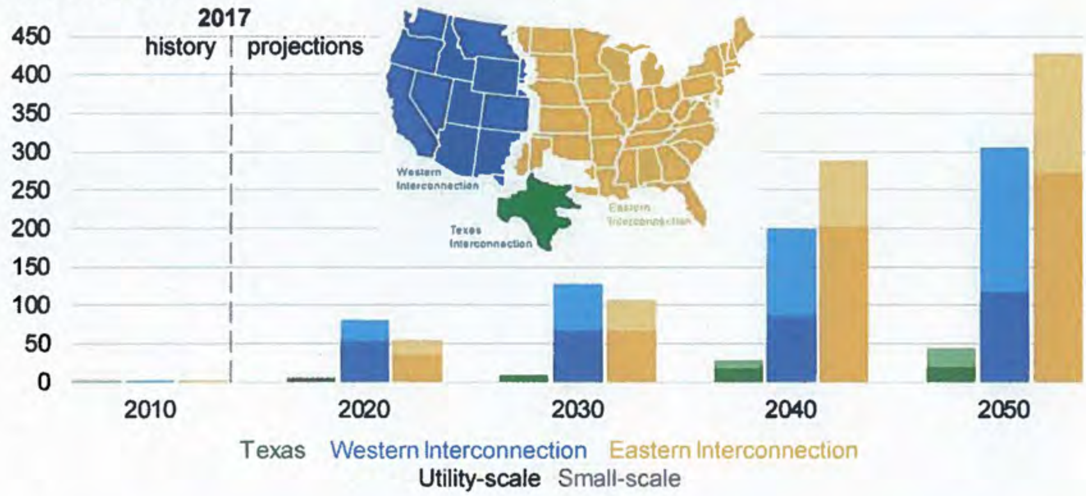


—support growth of energy storage capacity

- From 2020 to 2050, utility-scale wind capacity is projected to grow by 20 gigawatts (GW), and utility-scale solar photovoltaic capacity is projected to grow by 127 GW. Over this same period, utility-scale storage capacity is projected to grow by 34 GW.
- Battery-based storage costs are expected to continue to decline as utility-scale energy storage markets grow.
- Policies such as storage mandates in California and market participation rules in the PJM electricity market support near-term growth in storage systems to stabilize grid operations, improve utilization of existing generators, and integrate intermittent technologies such as wind and solar into the grid.
- In the longer term, wind and solar growth are projected to support economic opportunities for storage systems that can provide several hours of storage and enable renewables generation produced during the hours with high wind or solar output to supply electricity at times of peak electricity demand.

Projected solar PV cost competitiveness results in growth of solar generation in the Reference case in all interconnection regions—

Solar photovoltaic electricity generation by region (Reference case)
billion kilowatthours



—for both utility-scale and small-scale systems

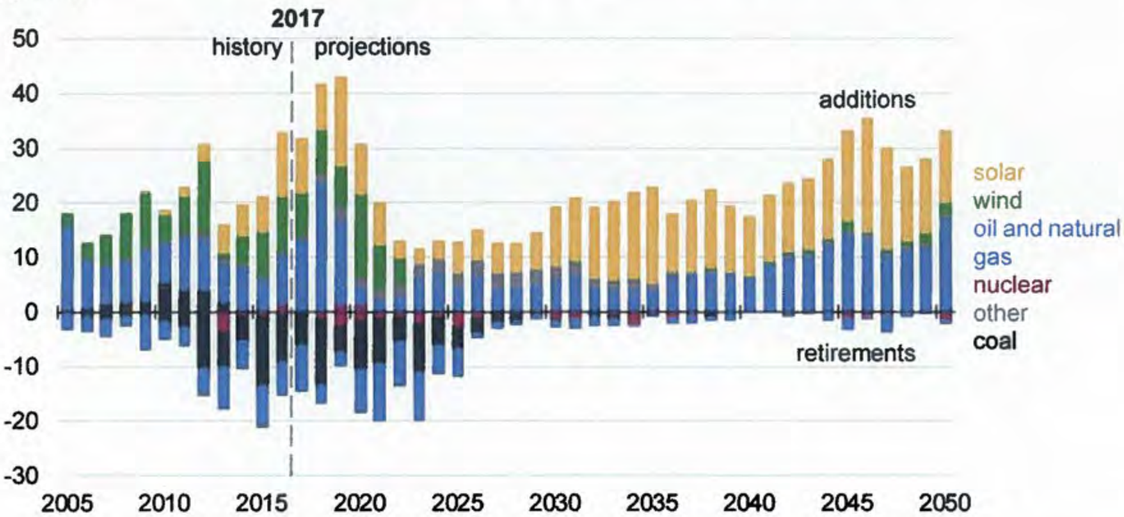
- Electricity generation from solar photovoltaic (PV) facilities in all sectors is projected to reach 14% of total electricity generation by 2050 in the Reference case, with 53% of the total from utility-scale systems and 47% from small-scale systems.

- In the Western Interconnection, growth in solar PV generation comes primarily from small-scale systems such as roof-top PV. In the Eastern Interconnection, solar PV generation is produced mostly from utility-scale systems through the projection period.

- The share of the Western Interconnection's solar PV generation to the U.S. total generally decreases over the projection period, from 66% in 2017 to 39% in 2050, as the penetration of solar PV installations increases in the Texas and Eastern Interconnections. By 2032, the Eastern Interconnection is projected to have the largest share of U.S. solar PV generation (49%) and that share increases through the projection period to 55% by 2050. Texas is estimated to generate about 6% of solar PV generation by 2050.

Renewables and natural gas comprise most of the capacity additions through the projection period in the Reference case—

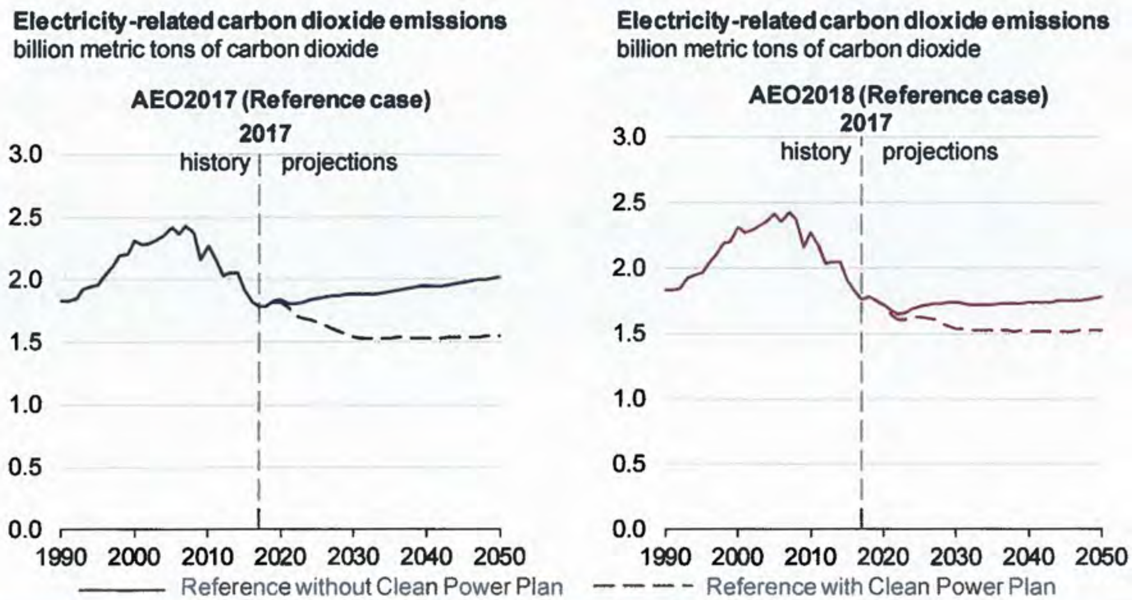
Annual electricity generating capacity additions and retirements (Reference case)
gigawatts



—with tax credit phase-outs and coal plant retirements accelerating additions of near-term renewables and natural gas-fired capacity

- Most electric generation capacity retirements occur by 2025, when natural gas prices are lower. They taper off in the later years of the projection period.
- In the Reference case, 80 gigawatts (GW) of new wind and solar photovoltaic (PV) capacity are added from 2018–2021, motivated by declining capital costs and the availability of tax credits.
- New wind capacity additions continue at much lower levels after the expiration of production tax credits in the early 2020s. Although the commercial solar investment tax credits (ITC) are reduced and the ITC for residential-owned systems expires, the growth in solar PV capacity continues through 2050 for both the utility-scale and small-scale applications.
- New natural gas-fired capacity is also added steadily through 2050 to meet growing electricity demand.

The projected effect of the Clean Power Plan on carbon dioxide emissions is smaller in AEO2018 than it was in AEO2017—



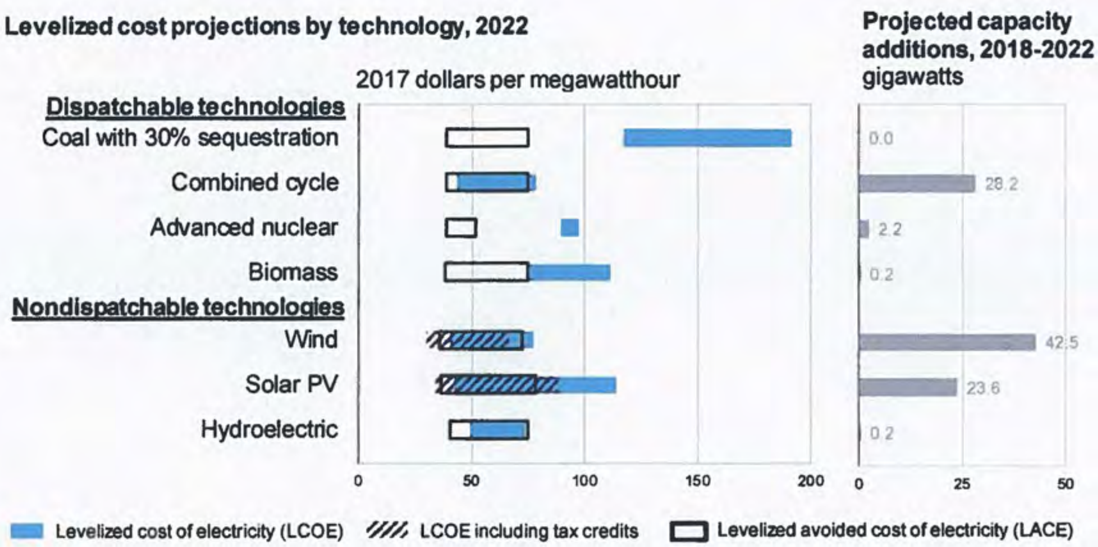
—because of lower projected levels for coal-fired generation even without the Clean Power Plan policy

- In the near term, the cumulative effect of increased coal plant retirements, lower natural gas prices, and lower electricity demand in the AEO2018 Reference case is a reduction in the projected carbon dioxide (CO2) emissions from electric generators, even without the Clean Power Plan (CPP). In 2020, projected electric power sector CO2 emissions are 1.72 billion metric tons, which is 120 million metric tons (7%) lower than the projected level of CO2 emissions in the AEO2017 Reference case without the CPP.

- By 2030, most of the additional planned coal unit retirements have occurred, and in the absence of the CPP, projected CO2 emissions stabilize in the Reference case at about 1.71 billion metric tons, which is 143 million metric tons (8%) below the AEO2017 Reference case without the CPP for that year.

- Over the long term, greater renewables growth in the AEO2018 Reference case results in electric power sector emissions growing at a slower rate, reaching 1.78 billion metric tons in 2050, which is 242 million metric tons (12%) below the level for that year in the AEO2017 Reference case without the CPP.

Combined cycle, wind, and solar photovoltaic generation have the most favorable cost characteristics—



—when the levelized cost and levelized avoided cost of electricity are considered together

- Comparisons of levelized cost of electricity (LCOE) across technologies can be misleading because different technologies serve different market segments.
- The levelized avoided cost of electricity (LACE) is a measure of what it would cost to generate the electricity that is otherwise displaced by a new generation project.
- Overlap in the levelized cost and levelized avoided cost indicates favorable economics for new builds for that technology.
- Wind plants entering service in 2022 that started construction in 2018 will receive an inflation-adjusted federal production tax credit of $14/megawatthour; solar plants entering service in 2022 will receive a 26% federal investment tax credit, assuming a two-year construction lead time.

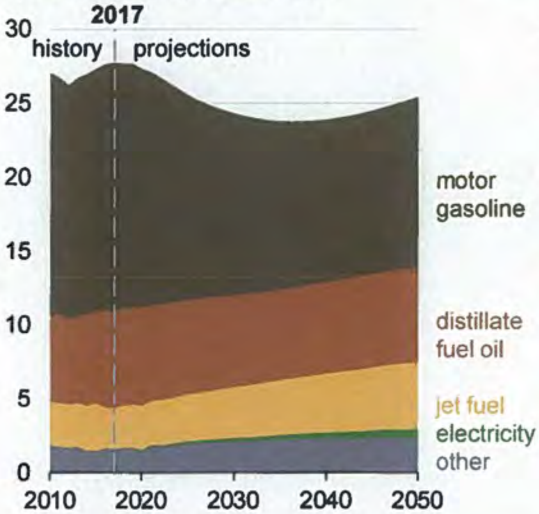
See more information in EIA's LCOE/LACE report on EIA's website.

Transportation

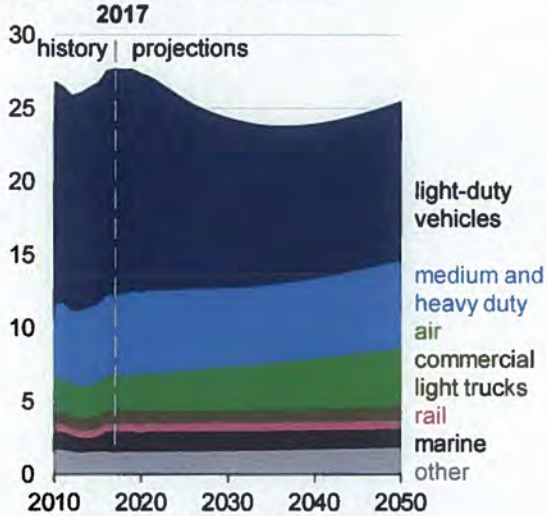
Transportation energy consumption peaks in 2017 in the Reference case because rising fuel efficiency outweighs increases in total travel and freight movements, but the trend begins to reverse in the second half of the projection period.

Transportation energy consumption declines between 2019 and 2035 in the Reference case—

Transportation sector consumption by fuel type
quadrillion British thermal units



Energy consumption by travel mode
quadrillion British thermal units

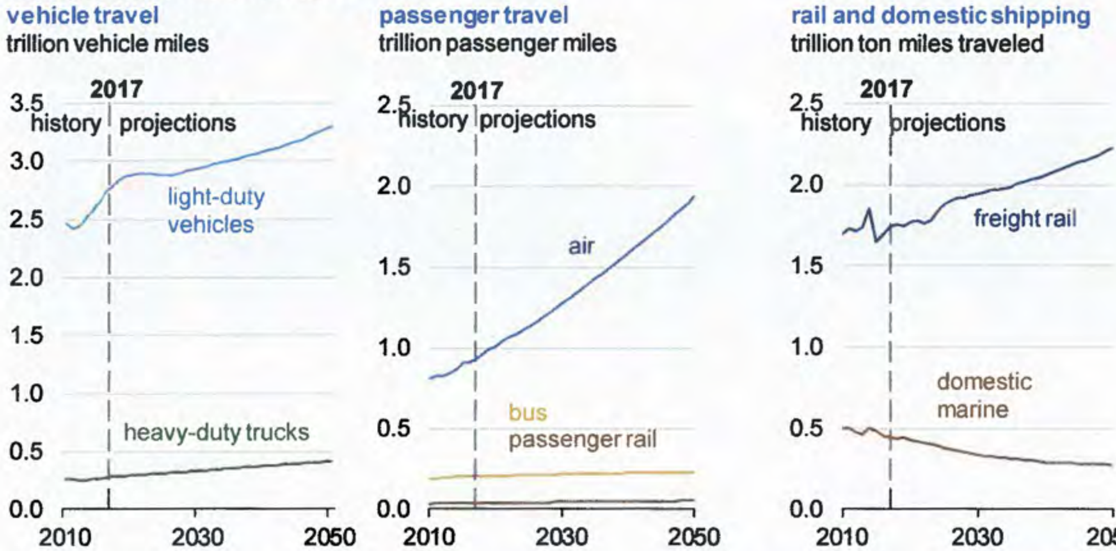


—because increases in fuel economy more than offset growth in vehicle miles traveled

- Increases in fuel economy standards temper growth in motor gasoline consumption, which decreases by 31% between 2017 and 2050.
- Increases in fuel economy standards result in heavy-duty vehicle energy consumption and related diesel use ending at approximately the same level in 2050 as in 2017, despite rising economic activity that increases the demand for freight truck travel.
- Excluding electricity and other transportation fuels, which are at comparatively low levels in 2017, jet fuel consumption grows more than any other transportation fuel over the projection period, rising 64% from 2017 to 2050, as growth in air transportation outpaces increases in aircraft energy efficiency.
- Motor gasoline and distillate fuel oil's combined share of total transportation energy consumption decreases from 84% in 2017 to about 70% in 2050 as the use of alternative fuels increases.
- Continued growth in on-road travel demand increases energy consumption later in the projection period, because current fuel economy and greenhouse gas standards require no additional efficiency increases for new vehicles after 2025 for light-duty vehicles and after 2027 for heavy-duty vehicles.

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

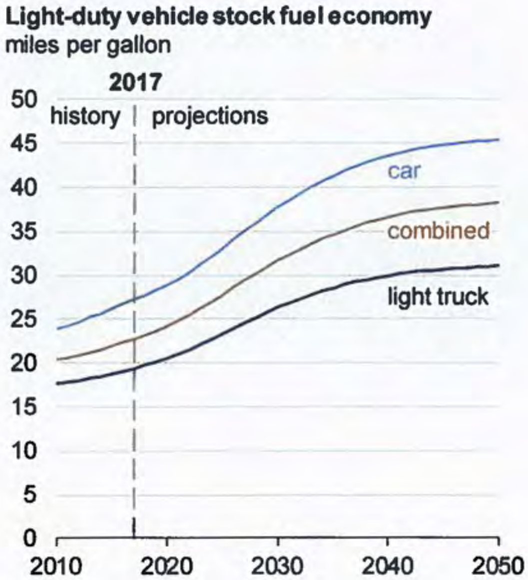
Transportation travel statistics

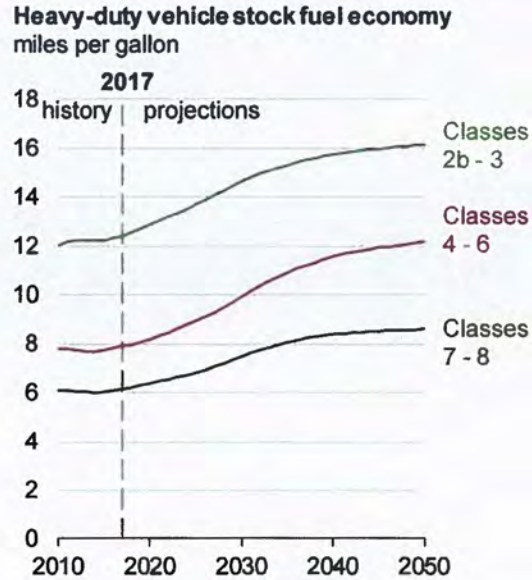


—and total freight movement increases

- Light-duty vehicle miles traveled increase by 18% in the Reference case, growing from 2.8 trillion miles in 2017 to 3.3 trillion miles in 2050 as a result of rising incomes and growing population.
- Truck vehicle miles traveled, the dominant mode of freight movement, grow by nearly 50%, from 384 billion miles in 2017 to 569 billion miles in 2050 as a result of increased economic activity. Freight rail ton miles grow by 27% over the same period, led primarily by rising industrial output. However, U.S. coal shipments, which are mainly via rail, remain relatively flat.
- Air travel doubles from 0.9 trillion revenue passenger miles to 1.9 trillion revenue passenger miles between 2017 and 2050 in the Reference case because of an increased demand for personal travel.
- Domestic marine shipments decline modestly over the projection period, continuing a historical trend related to logistical and economic competition with other freight modes.

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





—across all vehicle types through the projection period

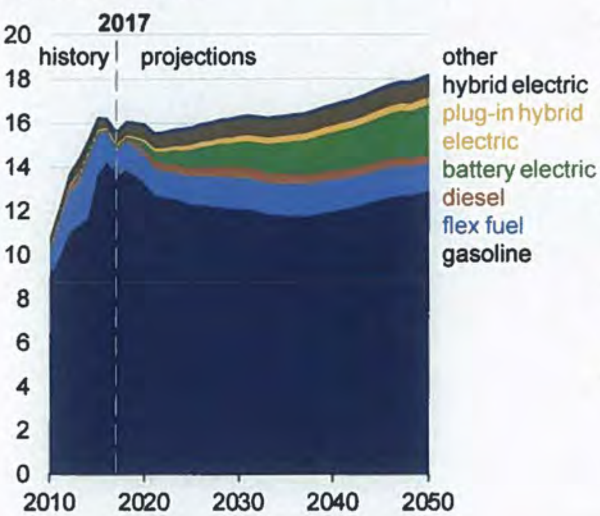
- Fuel economy of light-duty vehicles from 2017 to 2050 increases by 66% for cars and by 60% for light trucks. The combined fuel efficiency increases by 68% by 2050 as newer, more fuel-efficient vehicles enter the market, including a higher share of cars, which are more efficient than light trucks.

- Fuel economy of the heavy-duty vehicles improves across all weight classes as the second phase of heavy-duty vehicle efficiency and greenhouse gas standards takes full effect in 2027.

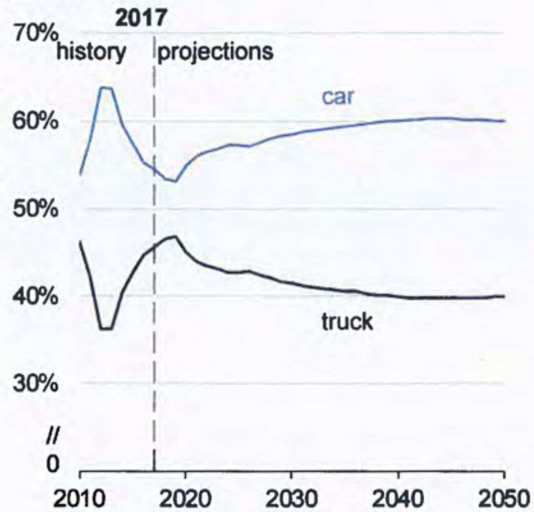
- Gains in fuel economy offset increases in on-road travel for both light-duty and heavy-duty vehicles. These gains keep heavy-duty vehicle energy consumption relatively flat and decrease light-duty vehicle energy consumption. After 2039, increasing vehicle travel outweighs fuel economy improvements, leading to increases in fuel demand.

Light-duty vehicle fuel economy improves as sales of more fuel-efficient cars grow and as electrified powertrains gain market share—

Light-duty vehicle sales by fuel type
millions of vehicles



Light-duty vehicle sales shares
percent

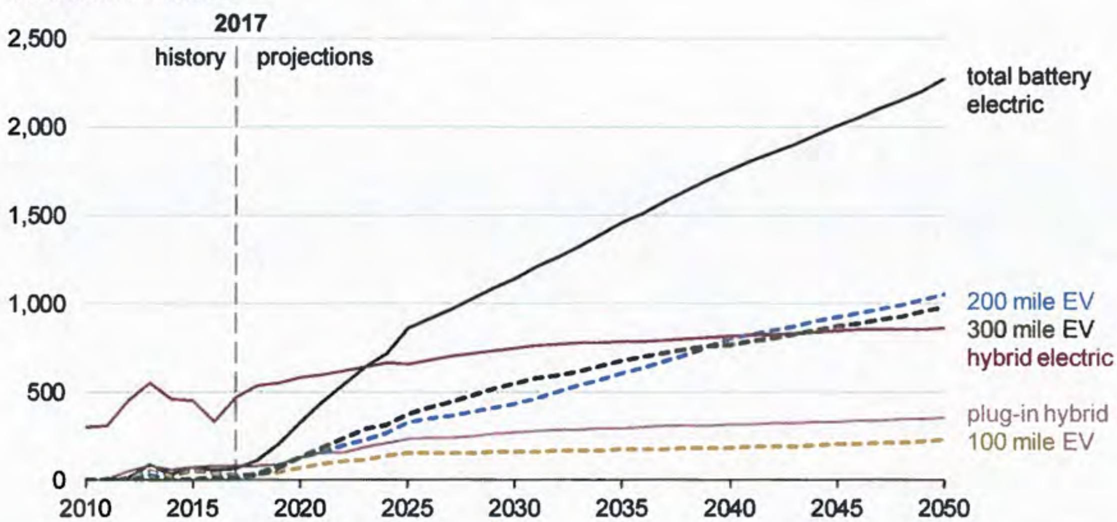


—but gasoline vehicles remain the dominant vehicle type through 2050 in the Reference case

- Combined sales of new electric, plug-in hybrid electric, and hybrid vehicles grow in market share from 4% in 2017 to 19% in 2050 in the Reference case.
- The combined share of sales attributable to gasoline and flex-fuel vehicles (which use gasoline blended with up to 85% ethanol) declines from 95% in 2017 to 78% in 2050 because of the growth in the sales of electric vehicles.
- Passenger cars gain market share relative to light-duty trucks because of their higher fuel efficiency in periods when motor gasoline prices are projected to increase and because crossover vehicles, often classified as passenger cars, increase in availability and popularity.
- New vehicles of all fuel types show significant improvements in fuel economy because of compliance with increasing fuel economy standards. New vehicle fuel economy rises by 45% from 2017 to 2050.

Sales of electric and plug-in hybrid electric light-duty vehicles increase in the Reference case—

New vehicle sales of battery powered vehicles
thousands of vehicles

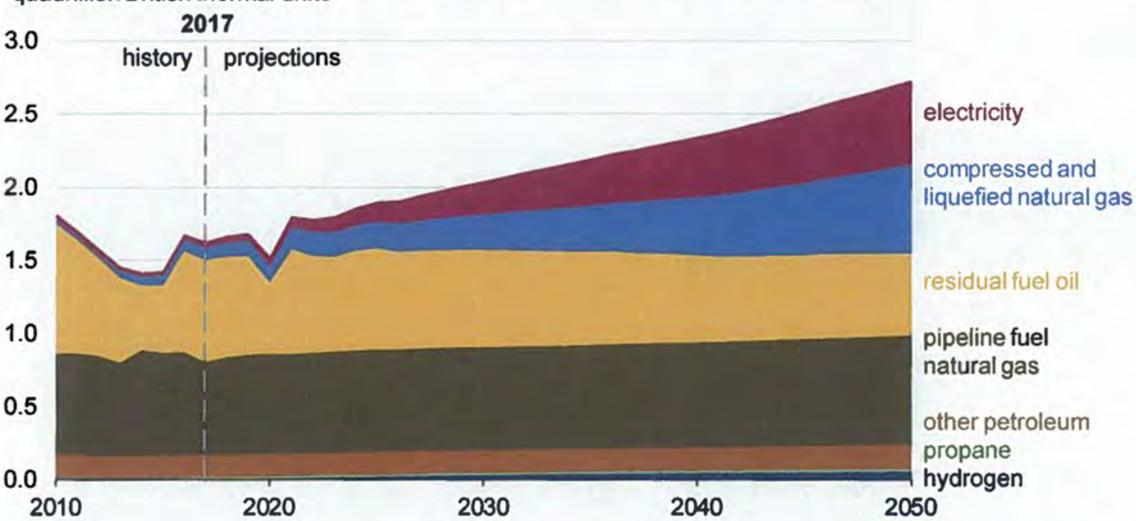


—driven by state policies, more models offering longer driving-range capabilities, and battery cost reductions

- Battery-electric vehicle (BEV) sales increase from less than 1% of total U.S. vehicle sales in 2017 to 12% in 2050. Plug-in hybrid electric vehicle (PHEV) sales increase from less than 1% to 2% over the same period.
- California's Zero-Emission Vehicle regulation, which has been adopted by nine additional states, requires a minimum percentage of vehicle sales of electric and plug-in hybrid vehicles. In 2025, the year the regulation and new federal fuel economy standards go into full effect, projected sales of BEV and PHEV vehicles reach 1.1 million, or about 7% of projected total vehicle sales in the Reference case.
- Sales of the longer-ranged 200- and 300-mile electric vehicles grow over the entire projection period, tempering sales of the shorter-range 100-mile electric vehicles and plug-in hybrid electric vehicles.

Consumption of total non-major transportation fuels grows considerably in the Reference case between 2017 and 2050—

Transportation sector consumption of non-major petroleum and alternative fuels
quadrillion British thermal units



—because of the increased use of electricity and natural gas

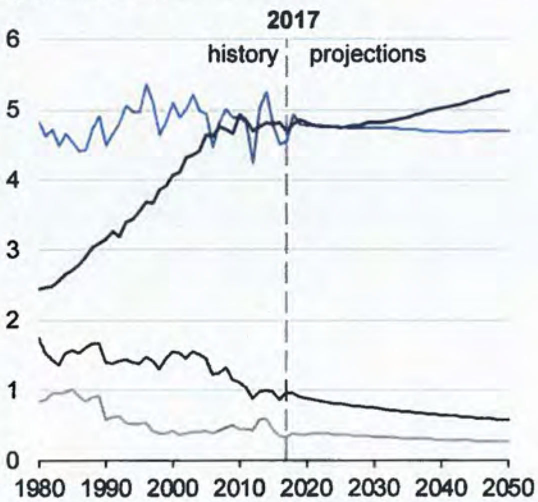
- Electricity use in the transportation sector increases sharply after 2020 in the Reference case because of the projected rise in the sale of new light-duty vehicles that are electric and plug-in hybrid-electric.
- Natural gas consumption increases over the entire projection period because of growing use in heavy-duty vehicles and freight rail.
- New limits on the air pollutants associated with the International Convention for the Prevention of Pollution by Ships (MARPOL) lead to some switching from residual fuel oil to liquefied natural gas in maritime vessels during later years of the projection period.

Buildings

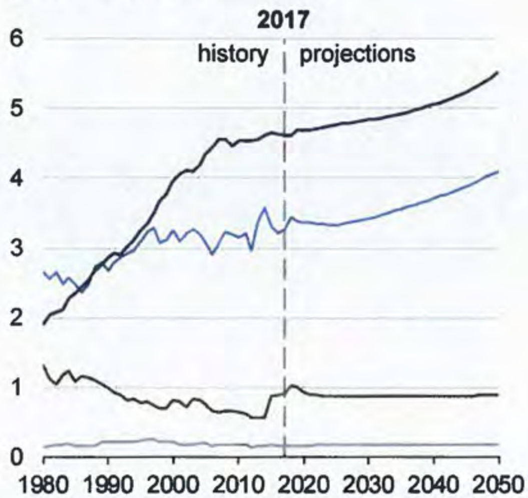
Delivered energy consumption in the buildings sector is expected to grow gradually from 2017 to 2050 in the Reference case based in part on currently established efficiency standards and incentives. Distributed solar capacity is anticipated to grow throughout the projection period based on near-term incentives, declining costs, and demographic factors.

Residential and commercial energy consumption grows gradually from 2017 to 2050—

Residential sector energy consumption
quadrillion British thermal units



Commercial sector energy consumption
quadrillion British thermal units

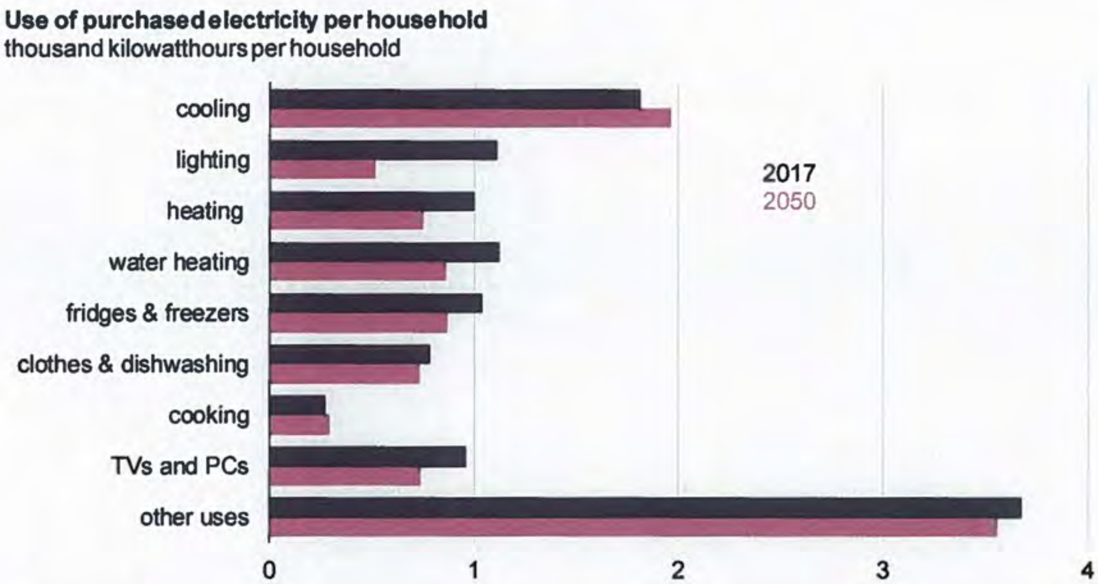


electricity natural gas petroleum and other liquids other

—led by modest electricity consumption growth in the residential and commercial sectors

- Energy delivered to the buildings sector (residential and commercial) grows 0.3%/year from 2017 to 2050 in the Reference case, accounting for 27% of total U.S. delivered energy in 2017 and 26% in 2050.
- In the buildings sector, efficiency gains, increases in distributed generation, and regional shifts in the population partially offset the impacts of growth in population, number of households, and commercial floorspace.
- Electricity accounts for most of U.S. buildings energy consumption growth in all AEO2018 cases, followed by natural gas. Consumption of delivered electricity would be even higher if not for the expected growth in distributed generation sources, particularly rooftop solar panels.
- Growth in commercial sector natural gas use later in the projection period reflects increased use of combined heat and power in the sector.

Residential electricity use per household decreases for most end uses—

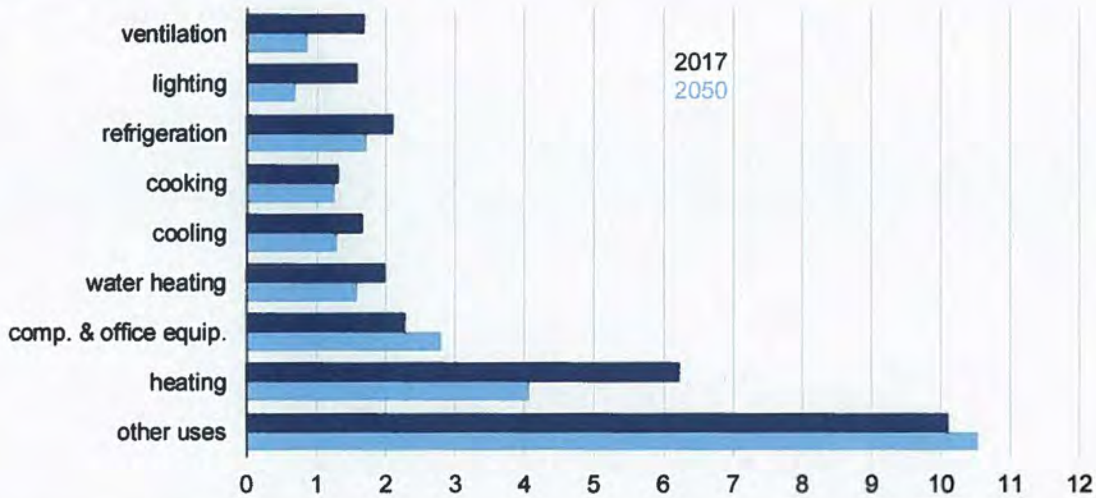


—as a result of increases in appliance energy efficiency standards and building energy codes

- Electricity use per household decreases in the Reference case through 2050, even as the number of homes grows 0.8%/year and the average size of homes grows 0.4%/year. In total, the use of purchased electricity per household decreases from 12,000 kilowatthours (kWh) in 2017 to 10,000 kWh in 2050.
- Continued population shifts to warmer parts of the United States lower heating demand and increase cooling demand in all cases in the residential sector. Heating and cooling demand are also affected by efficiency improvements.
- By 2050, the average household uses less than half as much electricity for lighting as it did in 2017, as more energy-efficient, light-emitting diodes replace incandescent bulbs and compact fluorescent lamps.
- Energy efficiency standards tighten for other uses, such as dehumidifiers, ceiling fans, pool pumps, and other miscellaneous loads, which lowers energy consumption per household in these end uses. However, increased adoption of electronic devices contributes to growth in residential use of electricity.
- Residential on-site electricity generation, mostly from photovoltaic solar panels, lowers total delivered electricity purchased from the electric grid over the projection period.

Commercial electricity use per square foot of commercial floorspace falls—

Use of purchased electricity per square foot of commercial floorspace
thousand kilowatthours per billion square feet



—as a result of adopting efficient LED lighting and the changing needs for space heating

- Electricity used for commercial HVAC equipment (heating, ventilation, and cooling) drops by more than one-third from 2017 to 2050 in the Reference case because of increases in energy efficiency and a continued population shift toward warmer parts of the country in the South and West. Commercial floorspace in the United States grows by 1% annually between 2017 and 2050.

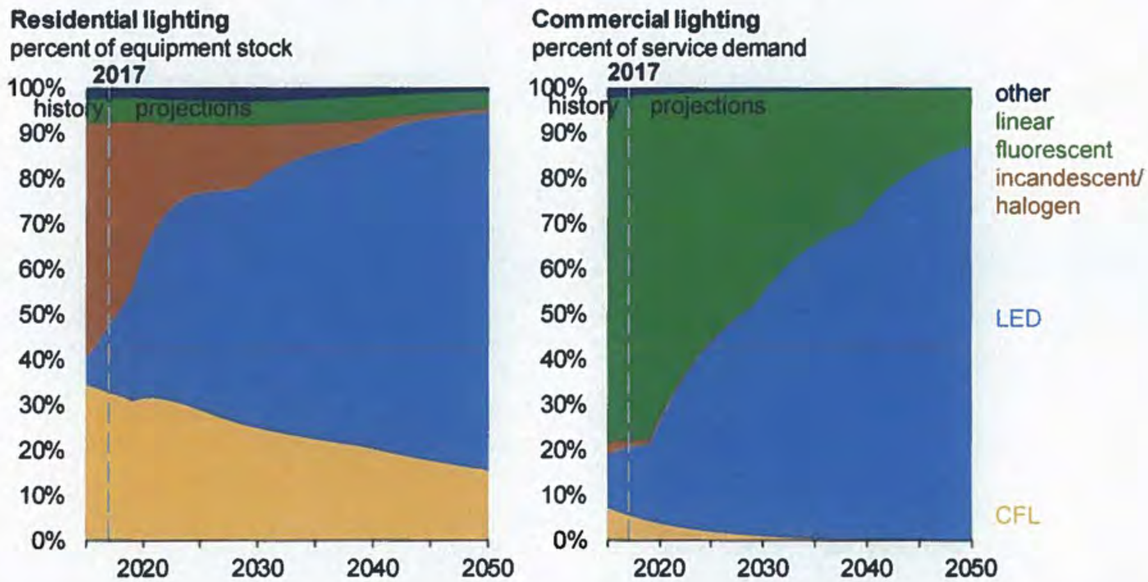
- Although the United States has no federally-mandated commercial building energy code, state- and local-level building codes reduce energy used for heating and cooling.

- Lighting standards and the increased efficiency of light-emitting diode (LED) bulbs result in a 56% decrease in lighting intensity between 2017 and 2050 in the Reference case, as LEDs displace linear fluorescent lighting as the dominant commercial lighting technology.

- Office equipment and other uses, such as information technology network and telecommunications equipment, are major contributors to growth in commercial sector electricity consumption in all cases.

- Commercial on-site electricity generation, mostly from solar photovoltaic panels and combined heat and power systems, lowers total delivered electricity purchased from the electric grid.

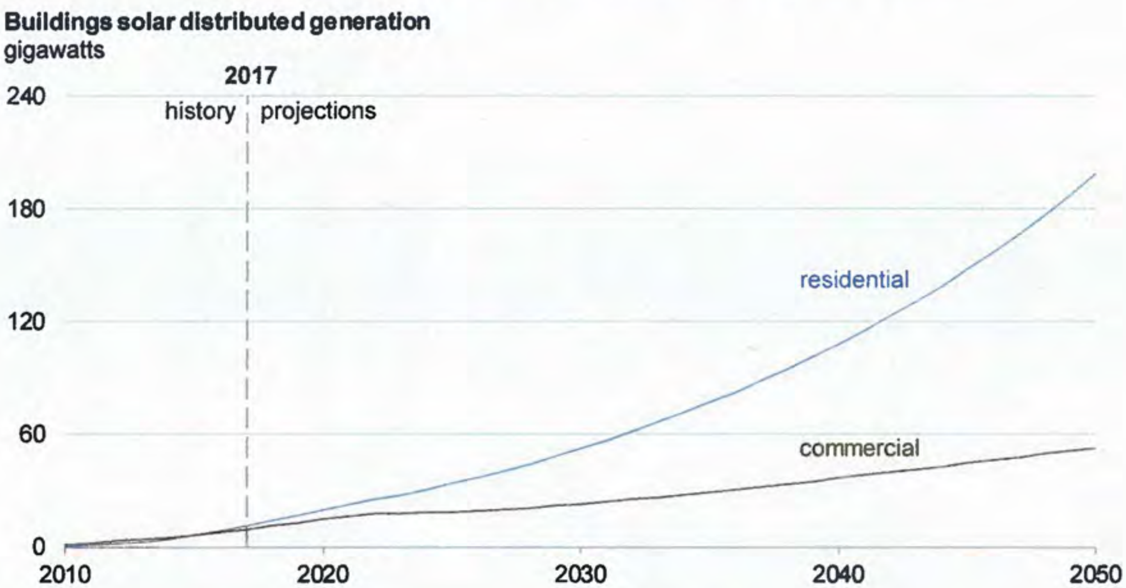
Energy efficiency incentives and standards contribute to rapid adoption of LED and CFL lighting in the near term—



—while lower costs associated with LEDs increase consumer use in later years

- Light-emitting diode (LED) adoption increases rapidly over the projection period. By 2050, LEDs meet most lighting demand in buildings across all cases.
- The use of compact fluorescent lamp (CFL) bulbs in residential buildings declines as the adoption of LED bulbs increases, a shift driven by lower LED prices and the gradual elimination of CFL subsidies through 2019.
- Utility and state energy-efficiency program incentives account for up to 30% of the cost for CFLs in 2014 and up to 55% of the cost for LEDs until 2019.
- Efficiency requirements under the Energy Independence and Security Act (EISA), which eliminate inefficient incandescent bulbs from general use after 2020, also bolster the adoption of LED lighting.
- LED prices decrease over the projection period, leading to further adoption. The purchase price of a typical LED light bulb decreases by about 70% between 2015 and 2050.

Solar photovoltaic adoption grows between 2017 and 2050—



—with residential growth outpacing commercial growth

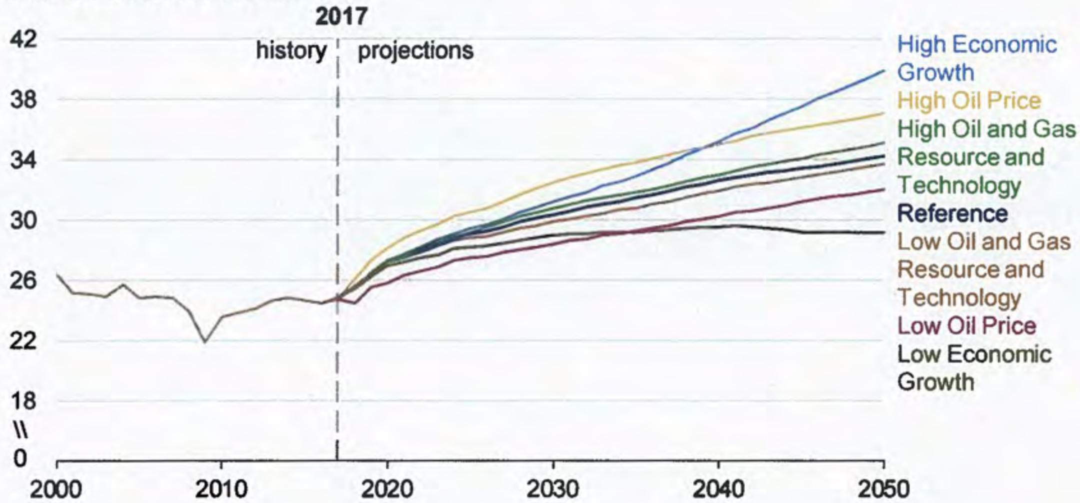
- In the Reference case, most distributed solar capacity growth occurs in the residential sector, which increases by 9%/year from 2017 through 2050, compared with 6%/year growth in the commercial sector.
- Rising incomes, declining technology costs, and social influences contribute to continued adoption of residential photovoltaic (PV), despite the phase-out and expiration of federal solar investment tax credits between 2019 and 2022.
- Stable retail electricity rates and economic considerations lead to slower but steady PV adoption by commercial consumers, as declining system costs offset the phasedown in the federal business investment tax credit from 30% in 2019 to 10% in 2022.
- Adoption of other distributed generation technologies, such as small wind and combined heat and power (mostly in the commercial sector), grows more slowly and reaches about 16 gigawatts (GW) of capacity by 2050 in the Reference case.
- The more robust economic assumptions in the High Economic Growth case lead to an additional 20 GW of solar PV capacity and an additional 1 GW of non-solar capacity by 2050 in the buildings sectors.

Industrial

With economic growth and relatively low energy prices, energy consumption in the industrial sector increases between 2017 and 2050 across all cases. Consumption of all energy sources except coal increases significantly. Energy intensity declines across all cases as a result of technological improvements.

Industrial delivered energy consumption grows in all cases—

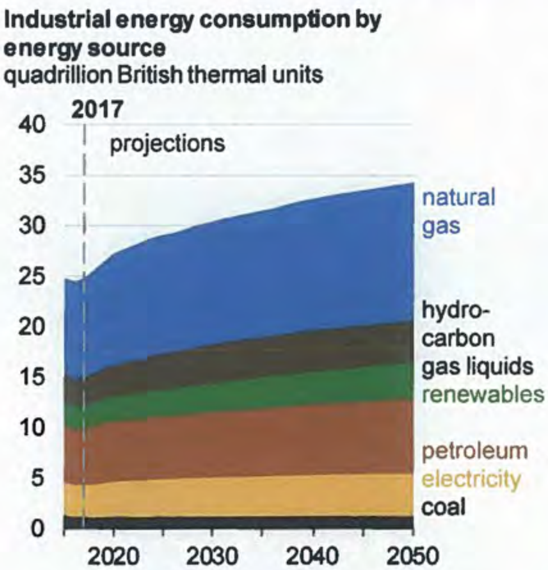
U.S. industrial delivered energy consumption
quadrillion British thermal units

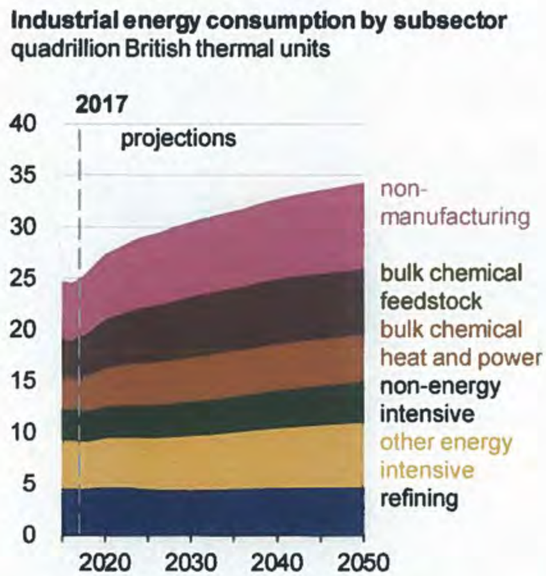


— driven by economic growth and relatively low energy prices

- Reference case industrial delivered energy consumption is projected to grow 38%, from 25 quadrillion British thermal units (Btu) to 34 quadrillion Btu, between 2017 and 2050.
- Industrial energy consumption is highest in the High Economic Growth case in 2050, reaching 40 quadrillion Btu, an increase of 61% from the 2017 levels, as more energy is used to produce products such as steel, fabricated metal products, and paper.
- Energy consumption in the High Oil Price case exceeds energy consumption in other cases before 2040 as a result of higher demand for U.S. products and greater amounts of energy used for natural gas liquefaction.

Industrial sector energy consumption increases at a similar rate for most fuels in the Reference case—





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

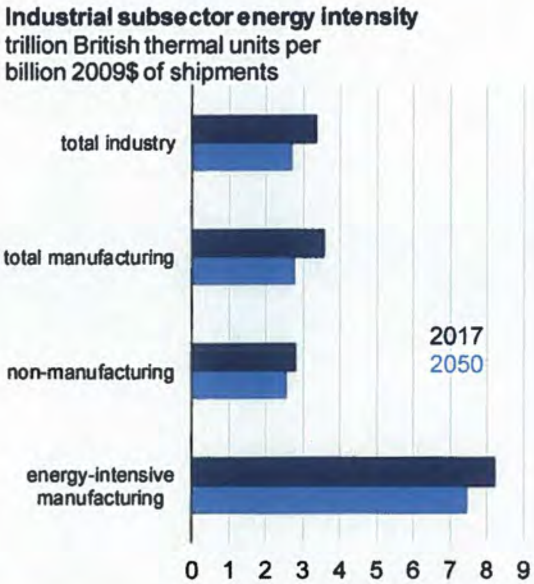
- Total industrial delivered energy consumption grows 1% per year from 2017 to 2050 in the Reference case. All fuels have a similar annual growth rate (1%, ±0.5%), with the exception of coal, which remains relatively flat through the projection period. Overall energy consumption in the industrial sector grows more slowly than economic growth because of efficiency gains.

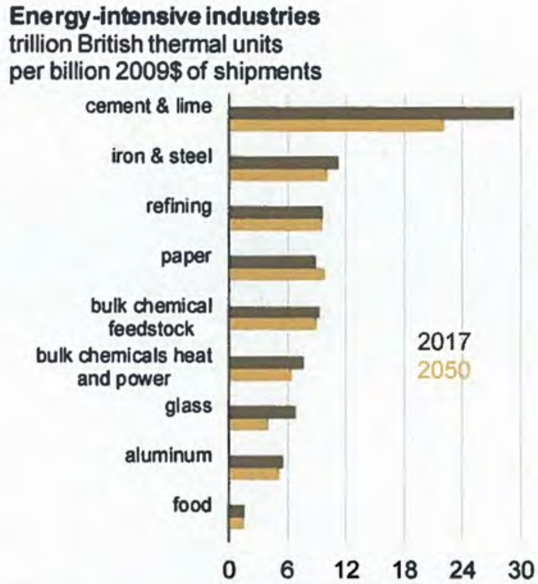
- Natural gas (used for heat and power in many industries) and petroleum (a feedstock for bulk chemicals) account for the majority of delivered industrial energy consumption. Hydrocarbon gas liquids such as ethane, propane, and butane are used as feedstock for bulk chemical production and are a major source of growth in industrial use of petroleum.

- The bulk chemicals industry constitutes about 30% of total industrial energy consumption through the projection period and is one the fastest growing energy-intensive industries, exceeding consumption of 10 quadrillion British thermal units in the Reference case by 2029.

- Nonmanufacturing industries' energy consumption grows at more than 1% per year from 2017 to 2050 as a result of relatively fast consumption growth in the mining and construction industries. Agriculture energy consumption growth is much slower.

In the Reference case, energy intensities decline in most energy-intensive industries—



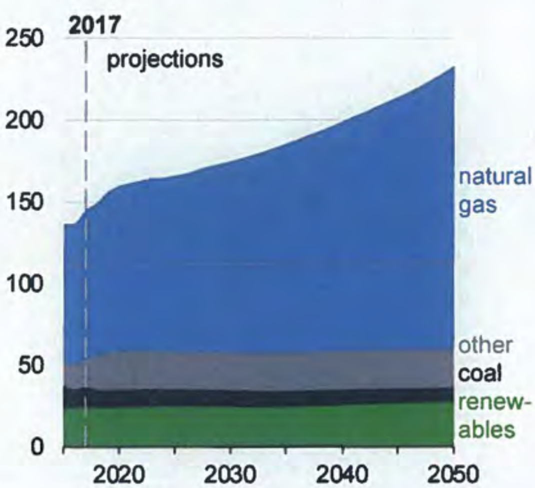


— reflecting efficiency gains in existing capacity and implementation of new, more energy-efficient technologies

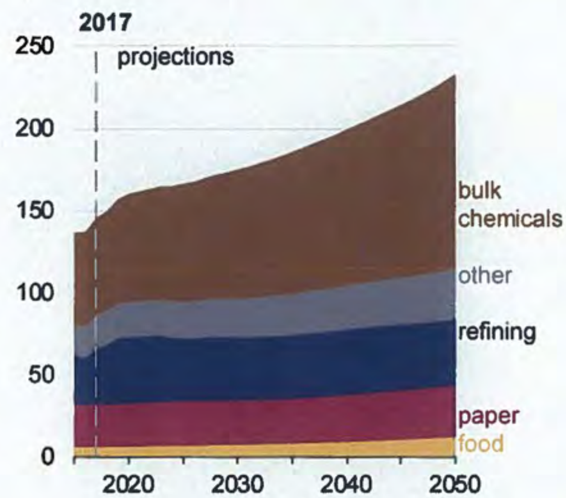
- Energy intensity (consumption per unit of output) in the industrial sector declines by about 0.6%/year from 2017 to 2050 in the Reference case.
- For manufacturing, energy intensity declines as a result of increases in energy efficiency in new capital equipment as well as a shift in the share of production away from energy-intensive industries toward non-energy intensive industries, such as metal-based durables, over time.
- Energy-intensive industries account for about 65% of total industrial energy consumption throughout the projection period in the Reference case, even though they almost always account for less than 25% of U.S. industrial output.
- Non-energy intensive manufacturing industries exhibit the greatest relative decline in energy use per unit of output—nearly 30% over the projection period—about three times greater than the declines in other industrial sectors.

Electricity generated by industrial combined heat and power technologies grows in the Reference case—

Combined heat and power generation by fuel
billion kilowatthours



Combined heat and power generation by industry
billion kilowatthours



—with most growth occurring in the bulk chemicals and food industries

- Electricity consumption associated with combined heat and power (CHP) production in the industrial sectors grows from 0.5 quadrillion British thermal units (Btu) in 2017 (more than 10% of total industrial electricity consumption) to 0.8 quadrillion Btu by 2050 (about 15% of total industrial electricity consumption) in the Reference case.

- Industrial CHP is most commonly used in large, steam-intensive industries—for example, the refining industry used CHP for about 40% of its electricity consumption in 2017, paper about 30%, and bulk chemicals about 20%. Continued penetration of CHP within these industries as well as growth in these industries lead to higher use of CHP over the projection period.

- CHP is most commonly generated with natural gas, but renewables such as black liquor (a byproduct of the pulping process) are used by the paper industry. Other byproduct fuels such as blast furnace gas and still gas are used in the iron and steel industry and the refining industry, respectively.

References

Commonly used acronyms and abbreviations used in this report

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 liquid(s)
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

In general:

- Projected values are sourced from:
  - *Short-Term Energy Outlook*, October 2017
  - Projections: EIA, AEO2018 National Energy Modeling System (runs: ref2018.d121317a, highprice.d122017a, lowprice.d121317a, highmacro.d121317a, lowmacro.d121317a, highrt.d121317a, lowrt.d121317a, ref_cpp.d121317a)
- Historical data are sourced from:
  - *Monthly Energy Review* (and supporting databases), September 2017
  - IHS Markit, Macroeconomic, Industry, and Employment models, August 2017

Historical values in some graphs are derived from other sources. For source information for specific graphs published in this document, contact annualenergyoutlook@eia.gov.

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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

REQUEST:

Refer to the IRP, pages 29-30 and 34 in which it discusses the weak coal demand.

a. Explain whether the expected reduction in capacity will strengthen East Bend's economic viability over the planning horizon.

b. Explain whether PJM will be capacity constrained as a result of the potential retirements. And if not, explain why not.

c. Compare and explain how often the East Bend unit is required to run by PJM for system support and how often the unit is selected to run due to its cost.

d. Discuss the modeled changes in the regional transmission organization generation fleet.

RESPONSE:

a. East Bend is an efficient unit and is currently competitive in the PJM market. As coal fired units continue to retire, competitive pressures on East Bend will be a function of the marginal cost of the capacity that replaces retiring generation. If natural gas prices remain a relatively low or lower levels and coal fired generation is replaced by new efficient gas fired generation or zero fuel cost renewable resources it is possible that there will be pressure on the operating capacity factor of East Bend.

b. PJM has not experienced system wide scarcities of generation in any of its annual capacity auctions; and has publicly reported that it does not anticipate coal retirements to drive capacity shortages. However, Duke Energy Kentucky has seen some impact of retiring coal fired generation. Due to specific generation retirements in Ohio prior to the 2021/2021 Planning Year, PJM determined that there were insufficient local resources and insufficient transmission capacity within PJM to import the required reserve margin of capacity. Consequently, the DEOK zone is one of the constrained Local Delivery Areas in 2020/2021 Base Residual Auction. While this situation does not directly impact Duke Energy Kentucky customers because the Company has sufficient capacity to meet its PJM obligation; and the zonal separation was limited to the 2020/2021 Planning Year; if it became necessary to secure additional capacity during future constrained years, the Company would be limited to resources that meet the deliverability requirements of the DEOK Zone. This limitation would drive decreased liquidity in the capacity market and potentially higher market prices for DEPK compliant capacity.

c. East Bend unit 2 has a relatively low variable operating cost and is typically offered to PJM with a commitment status of "Must Run" in the day-ahead and real-time PJM energy markets. The unit is typically economic to run, meaning the energy revenues received from PJM are greater than the variable costs to run the unit. In addition, the must run offer is made since this unit's longer startup time, like many coal units, makes commitment by PJM unpractical as the PJM day-ahead energy market is a 24 hour look ahead market. Even though the Company typically commits the unit in the PJM energy markets through this offer, PJM dispatches the unit anywhere between minimum and maximum output. Since the unit is typically already committed by the Company, it is difficult to tell how often the unit would have been required to run by PJM for system support since the Company has already committed the unit.

d. Please see pages 31-32 of the IRP.

PERSON RESPONSIBLE: John Verderame – a., b.
John Swez – c.
Scott Park – d.

STAFF-DR-02-015

REQUEST:

Refer to the IRP, pages 29. For Table 5.1, explain which gas price, coal price, and load assumptions are "most likely".

RESPONSE:

In terms of Table 5.1, "most likely" can be interpreted as the "Business as Usual" lines in Figures 4.5 and 4.6 for fuel and the bold lines in Figure 4.4 for load.

PERSON RESPONSIBLE: Scott Park

Duke Energy Kentucky
Case No. 2018-00195
STAFF Second Set Data Requests
Date Received: March 27, 2019

STAFF-DR-02-016

REQUEST:

Refer to the IRP, pages 37.

a. Explain whether the statement "A steady increase in the amount of solar PV (10 MW per year) and battery storage (2 MW per year) on the Duke Kentucky system would not significantly change the operation of East Bend 2 or Woodsdale over the planning horizon in a business as usual future" means that the additions will occur annually through 2032.

b. Explain whether this is in direct response to customers expressing a desire for green energy.

RESPONSE:

a. Since Duke Energy Kentucky is in the PJM market, East Bend 2's and the Woodsdale unit's operation is in response to the prevailing PJM market price. The additions of this amount of solar and storage are not expected to change to market price for power and as a result would not change the operation of East bend 2 and Woodsdale.

b. The measured addition of renewable generation is intended to transition the fleet over time so that once carbon regulation comes into place, the abruptness of the change in regulation will be less abrupt to customers. Customers are expressing some preference for more renewable energy as are potential new customers for the Duke Energy Kentucky system.

PERSON RESPONSIBLE: Scott Park

STAFF-DR-02-017

REQUEST:

Refer to the IRP, pages 47, the paragraph titled Cost of Renewables.

a. Explain if it is reasonable to expect that as demand on the grid increases and more coal units retire while there is a greater role for battery storage to play, that at best, battery storage will be an incremental player in terms of grid support.

b. Explain if Duke Kentucky expects that the gas generation units carry the majority of grid support as coal units retire.

RESPONSE:

a. Battery storage can provide many different value streams across the transmission, distribution and generation systems. It not only can harden the T&D system, but can also provide ancillary services such as frequency regulation, can help with the integration of renewable generation, and can shift energy to times of peaking needs. Duke Energy Kentucky would expect energy storage to be an important part of our grid infrastructure going forward.

b. As coal units retire, based on current natural gas price outlook, we believe that in the short-term gas generating units will supply the majority of energy and grid support requirements from retired coal unit retirements. In the long term, as renewable energy resources continue to become more economic, they will likely supply more of these energy and grid support requirements.

PERSON RESPONSIBLE: Scott Park/Zachary Kuznar – a.
John Verderame – b.

REQUEST:

Refer to the IRP, pages 48. Discuss the changes in requirements for PJM participation, including Capacity Performance, that Duke Kentucky is monitoring and how those changes are affecting Duke Kentucky.

RESPONSE:

Upon completion of the Woodsdale dual fuel project, currently scheduled for June 2019, Duke Energy Kentucky feels that its generation resources meet the increased reliability standard set out under Capacity Performance. The IRP reference to changes in requirements does not reflect specific changes to Capacity Performance; but rather any market rule changes that could impact Duke Energy Kentucky customers. PJM regularly modifies the markets it administers to improve efficiency and effectiveness of markets and increase reliability. Duke Energy Kentucky monitors this activity through active participation in the PJM stakeholder process.

As an example, there are currently three significant modifications to PJM rules that Duke Energy Kentucky is monitoring. Broadly these activities include Capacity Market reforms, and Energy Market reforms. Regarding Capacity Market reform, PJM has submitted for FERC approval several changes to the application of its Minimum Offer Price Rule to generators. As an FRR entity, these proposed changes do not immediately impact Duke Energy Kentucky customers; however, if Duke Energy Kentucky were to choose to move out of the FRR construct, the final form of changes could impact future planning decisions.

Duke Energy Kentucky is also tracking the Independent Market Monitors complaint to FERC proposing changes to the market seller offer cap to reflect a lower actual Capacity Performance assessment hour risk. Again, as an FRR entity, Duke Energy Kentucky is largely unaffected by this change; however, if the scope of this complaint broadens to include the calculation of the Capacity Performance Penalty rate, which expected assessment hours is a component of, there could be a significant impact to generation performance risk that Duke Energy customers are exposed to. Expected assessment hours is the denominator of the penalty calculation. As example, currently at 30 expected hours, if the expected hours were to change to 10 hours, the hourly Capacity Performance Assessment penalty would rise from the current roughly $3,500/ MW Hour to over $10,000/ MW Hour. To be clear, such a move has not been proposed; but would be impactful if it were.

Regarding Energy Market reforms, PJM has proposed changes to the Ancillary Service Reserve market. These modifications impact Duke Energy Kentucky through resultant higher energy market prices. Duke Energy Kentucky has been supportive of changes such as this that improve reliability and transparency in PJM markets.

PERSON RESPONSIBLE: John Verderame

STAFF-DR-02-019

REQUEST:

Refer to the IRP, pages 55-56, paragraph titled Peak Load, page 61, paragraph titled Peak Weather Data and page 93, the paragraph beginning "Regarding Weather Normalization."

a. On page 93, in the Response to Recommendation, normal weather is defined as a 30-year average. Regarding the sensitivity analysis, explain if Duke considered using a shorter, more recent average.
b. Explain if there are any Duke Kentucky studies showing the sensitivity of forecast results using a shorter timeframe to construct the average. And if so, explain how these studies affect the forecasted outcomes.
c. Explain if the Moody's reports were used as a basis for economic modeling discuss normal weather.
d. Explain if Duke Kentucky is aware of any National Oceanic Atmospheric Administration studies discussing the efficacy of defining normal weather using a standard different from the 30-year standard.
e. Describe the weather normalization calculations and process.

RESPONSE:

a. Duke did not consider using a shortened normalization period as part of this IRP process. No calculations were performed for any other normalization period.
b. No such studies were performed for Duke Energy Kentucky.

c. Moody's Analytics only supplies Duke Energy with an economic forecast. No data of theirs is part of any weather-normalization calculation.

d. Duke Energy Kentucky is not aware of a NOAA study like the one described.

e. Normal weather for the energy forecast is based on the arithmetic mean temperature of each date over the last thirty years. The daily average is used to calculate the appropriate number of heating- (or cooling-) degree days for that date, and these are aggregated by month to produce the normalized degree days. The same process—producing an average for time of peak over the last thirty years—is used to calculate weather for the time of peak in the forecast.

PERSON RESPONSIBLE: Benjamin W. Passty, Ph.D.

STAFF-DR-02-020

REQUEST:

Refer to the IRP, pages 57-58.

a. Explain what is driving the rise in forecasted natural gas prices.

b. Explain how the costs of production, gas exports, and pipeline capacity are changing.

RESPONSE:

a. Please also see the brief discussion of natural gas pricing in section IV-B. Duke Energy utilized a long term natural gas price forecast from IHS Markit Ltd., a leading energy consulting firm.

In the near term, supply increases in associated gas from oil production and gas drilling in Appalachia are expected to mitigate demand-side increases, keeping prices relatively low. In the mid to longer term, increasing demand from the power sector and exports (LNG and Mexico) are expected to drive prices higher as demand exceeds associated gas production gains, Appalachian production stabilizes, and costlier supplies are required.

b. Production costs generally have decreased, resulting in lower market prices compared to the previous decade. Technological improvements, specifically hydraulic fracturing and extended lateral lengths, are the primary reasons for enhanced per-well productivity and improved drilling economics. Hydraulic fracturing also broadened the economic resource base, as the technology enables economic recovery of shale resources that otherwise were more costly.

Exports via LNG terminals and to Mexico are forecast to increase over the next two decades, adding demand-side pressure. The exact impact is difficult to predict, as LNG exports are subject to international competition and new export terminals have an approximate five-year lead time.

Although industry data suggests pipeline costs are increasing, costs for greenfield pipeline capacity are difficult to predict and depend upon many factors. Moreover, several US pipeline projects have been delayed or canceled due to permitting challenges. In the eastern and midwestern US, some interstate pipelines have become bidirectional, or reversed flow from northward to southward, due to increased production in Appalachia and increased demand in the south. IHS Markit forecasts a need for incremental pipeline capacity from supplies in Texas and Appalachia.

PERSON RESPONSIBLE: Andrew James

STAFF-DR-02-021

REQUEST:

Refer to the IRP, pages 57 and 93.

a. Explain how effective Duke Kentucky's inverted block rate structure is in tempering residential energy consumption.

b. In theory, the time-of-day rates and the inverted block rate structure provide incentives to conserve energy. Explain if the effectiveness of these rate structures been analyzed. If so, provide the reports or other analysis describing the effectiveness of each rate structure.

c. Explain if there is a demonstrable difference in the price elasticity of energy over the range of the inverted block rate structure.

d. Refer to page 93, in the first paragraph and explain if the price increases in the inverted block are equal to or greater than the 12 percent price increase necessary to reduce usage by 1 percent.

e. Explain whether Duke Kentucky promotes duel fuel heat pumps and whether this technology would help abate winter electric peaks if widely utilized.

RESPONSE:

a-d. Duke Energy Kentucky's residential inverted block rate structure was eliminated as part of case No. 2006-172. The reference in the IRP was in error. The reference to the inverted block rate structure has no impact to the IRP results.

e. While the Duke Energy Kentucky's Residential Smart $aver Program is not intended to promote fuel switching and is agnostic to the heating fuel source utilized by a high-efficiency heat pump that is incentivized under the program, the Company does promote dual fuel heat pumps to the extent that the Program's incentive goes to customers that elect to install duel fuel heat pumps. At this time, the Company has not performed any specific analysis surrounding the winter-peak electric impact that dual fuel heat pumps or any other fuel-switching technology may have on Duke Energy Kentucky's load.

PERSON RESPONSIBLE: a-d Scott Park
e Tim Duff

Duke Energy Kentucky
Case No. 2018-00195
STAFF Second Set Data Requests
Date Received: March 27, 2019

STAFF-DR-02-022

REQUEST:

Refer to the IRP, page 61.

a. Provide Itron's report describing appliance efficiencies and saturations.

b. Provide and describe the Itron SAE Models.

RESPONSE:

a. Please see STAFF-DR-02-022 Attachment 1 for the Residential report and STAFF-DR-02-022 Attachment 2 for the Commercial report.

b. Please see Appendix B of STAFF-DR-02-022 Attachment 1 and Appendix A of STAFF-DR-02-022 Attachment 2 which gives information as to the motivation and structure of these models as provided by ITRON.

PERSON RESPONSIBLE: Benjamin W. Passty, Ph.D.

Itron

Residential Statistically Adjusted End-Use (SAE) Spreadsheets – 2018 AEO Update

The Residential SAE spreadsheets and models have recently been updated based on the Energy Information Administration's (EIA) *2018 Annual Energy Outlook (AEO)*. The updated spreadsheets reflect the Reference case, which no longer includes the impact of the Clean Power Plan (CPP).

The 2018 residential SAE spreadsheets and *MetrixND* project files include:

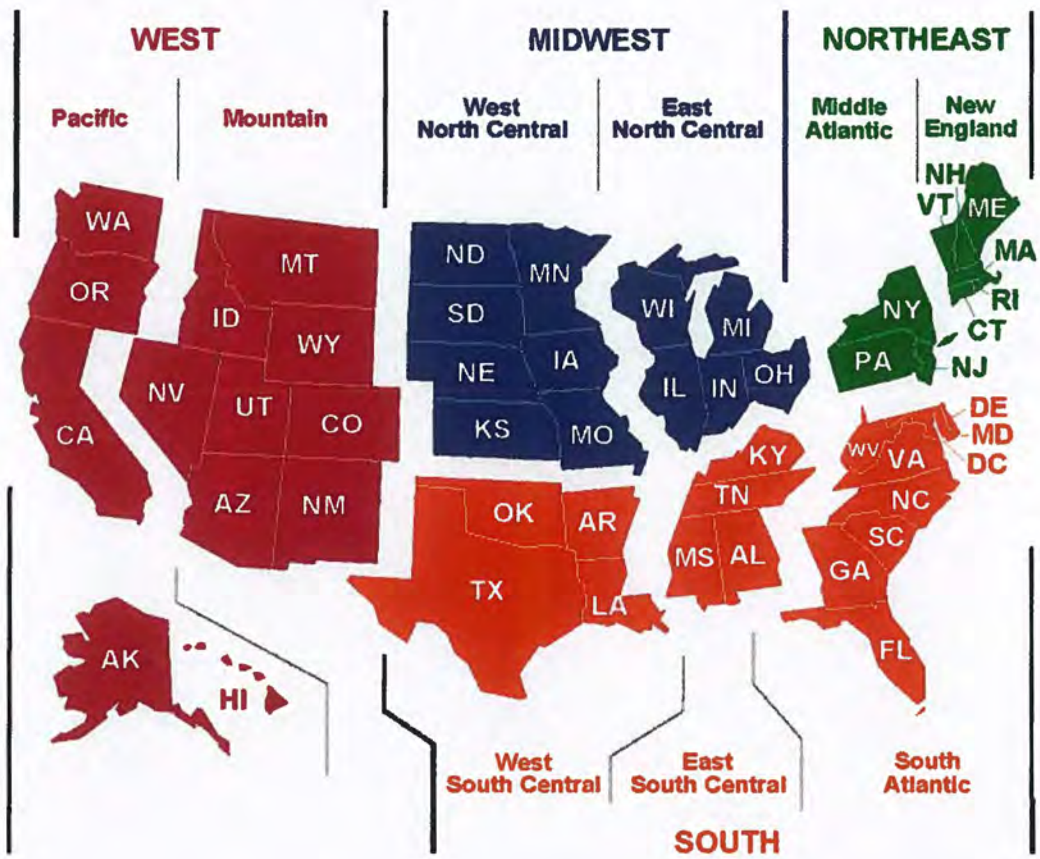
- Updated equipment efficiency trends
- Updated equipment and appliance saturation trends
- Updated structural indices
- Updated annual heating, cooling, water heating, and Non-HVAC indices
- Updated regional sales forecasts

End-use saturation, efficiency, structural changes (building shell efficiency improvements and square footage projections), and base-year end-use energy use are combined to develop historical and projected end-use intensity estimates. Resulting intensities can be used in constructing heating, cooling, and other use variables for residential average use and total sales forecast models.

EIA end-use saturation, efficiency and annual appliance usage (UEC – Unit Energy Consumption) are derived from the National End-Use Model System (NEMS). While NEMS generates detailed end-use data, EIA is primarily concerned with the high-level projection of total energy requirements (measured in Btu) across all end-uses and sectors including transportation. From an electric or natural gas utility forecaster's perspective, it is the underlying end-use and technology level detail that provides insights into how individual residential and commercial customers are using electricity and natural gas, trends in end-use energy consumption, and what these trends imply for future electric and gas usage at the regional level.

EIA provides end-use detail for nine census divisions, depicted in Figure 1.

Figure 1: Forecast Census Divisions



The 2018 AEO forecast base-year is 2009. Base-year end-use UEC, saturations and efficiency are derived from the 2009 Residential Energy Consumption Survey (RECS). The NEMS model, tracks end-use saturation and stock efficiency change over time with changes in customer appliance choices in the new home and replacement markets. Appliance choice decisions are driven by appliance costs, efficiency options and standards, natural gas availability, and fuel prices for electricity and natural gas. Forecasts are developed for three housing types – single family, multi-family, and mobile homes, for twenty end-uses, including:

- Resistance heating/furnaces
- Air-source heat pumps (heating)
- Ground-source heat pumps (heating)
- Secondary heating

- Central air conditioning
- Air-source heat pumps (cooling)
- Ground-source heat pumps (cooling)
- Room air conditioning
- Water heating
- Cooking
- 1st refrigerators
- 2nd refrigerators
- Freezers
- Dishwashers
- Clothes washers
- Clothes dryers
- TVs and related equipment
- Furnace fans
- Lighting
- Miscellaneous

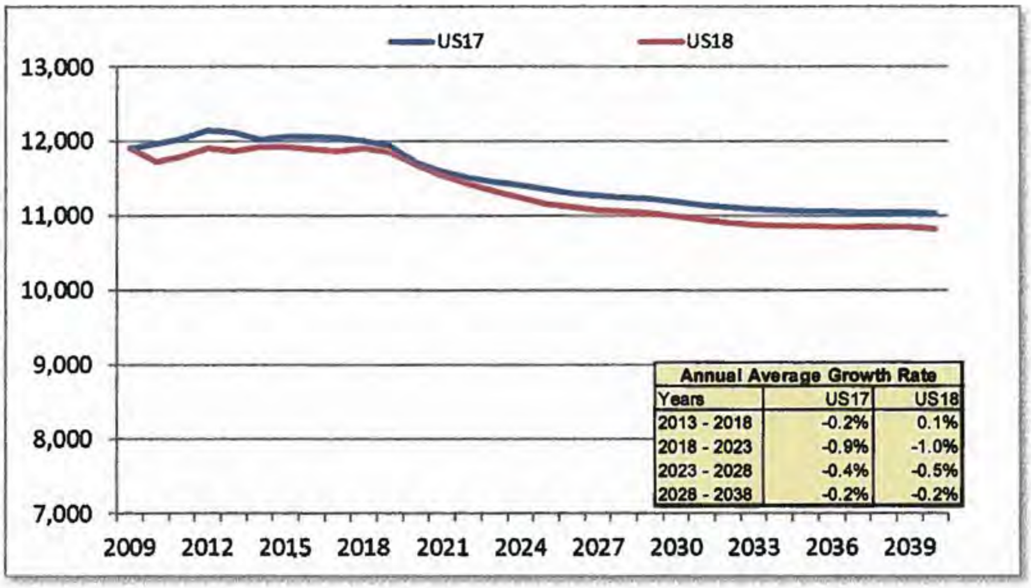
In the Statistically Adjusted End-Use (SAE) model, detailed end-use data derived from the EIA forecasts is used to construct end-use intensities (kWh per household) that are then integrated into monthly heating, cooling, and other use model variables. These variables are then used to forecast utility-level residential and commercial sales through estimated linear regression models. This approach allows utilities to capture the significant improvements in energy efficiency reflected in past usage and to account for expected improvements due to standards, new technologies, as well as state and utility efficiency programs in the future.

To support econometric modeling, Itron maintains and updates historical end-use data trends that are consistent with the 2009 RECS and earlier RECS (such as the 2005 RECS). Doing so sometimes requires adjusting historical end-use saturation and efficiency trends to reflect what EIA believes is the current state of appliance ownership, stock efficiency, and housing characteristics. The 2018 SAE spreadsheets reflect Itron's best estimates of historical end-use saturations, efficiency, and usage given EIA's 2009 base-year starting point and past estimates of end-use stock characteristics. This is the last year the AEO forecast will be based on the 2009 RECS. Going forward, the AEO forecast will be based on the more recent 2015 RECS.

Changes from 2017 Forecast - Electricity

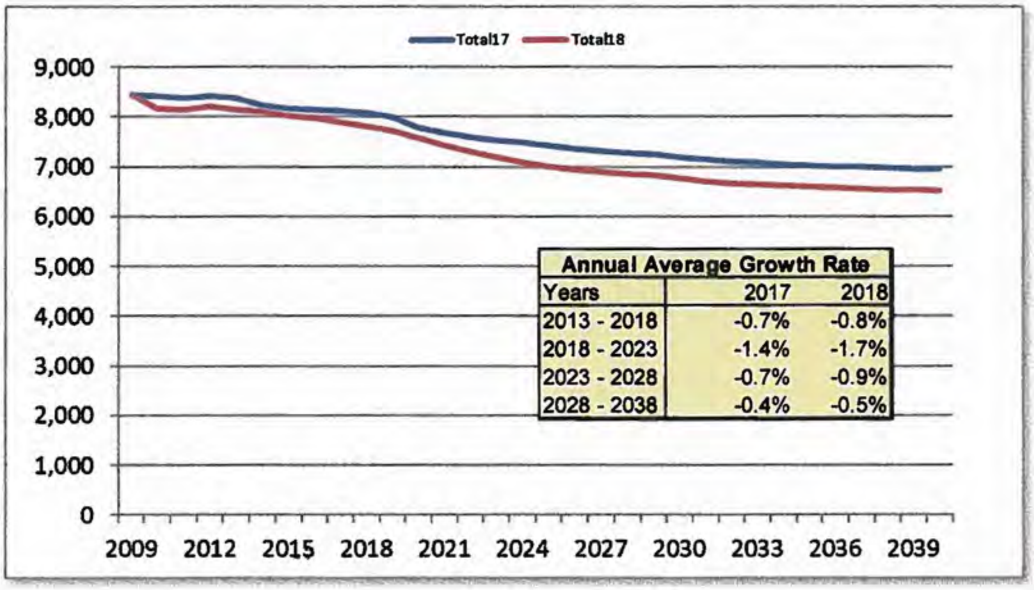
Figure 2 compares the SAE 2017 and SAE 2018 residential total household intensity projections for the U.S. Intensities are measured in kWh per household. Both 2017 and 2018 forecasts exclude CPP adjustments.

Figure 2: U.S. Residential Total Intensity (kWh/household)



The 2008 total intensity is lower on an absolute basis and declines at a slightly faster rate; each year, EIA forecasts lower long-term energy intensities. In the updated forecast, total intensity declines on average 1.0% through 2023 compared with last year's forecast of 0.9% average annual decline. Over the next five years total intensity averages 0.5% decline compared with 0.4% decline in the 2017 forecast. Growth rate differences are even larger across some of the census divisions. Figure 3, for example, compares Mid-Atlantic census division 2017 and 2018 energy intensities.

Figure 3: Mid-Atantic Energy Intensity (kWh/household)



Annual Average Growth Rate		
Years	2017	2018
2013 - 2018	-0.7%	-0.8%
2018 - 2023	-1.4%	-1.7%
2023 - 2028	-0.7%	-0.9%
2028 - 2038	-0.4%	-0.5%

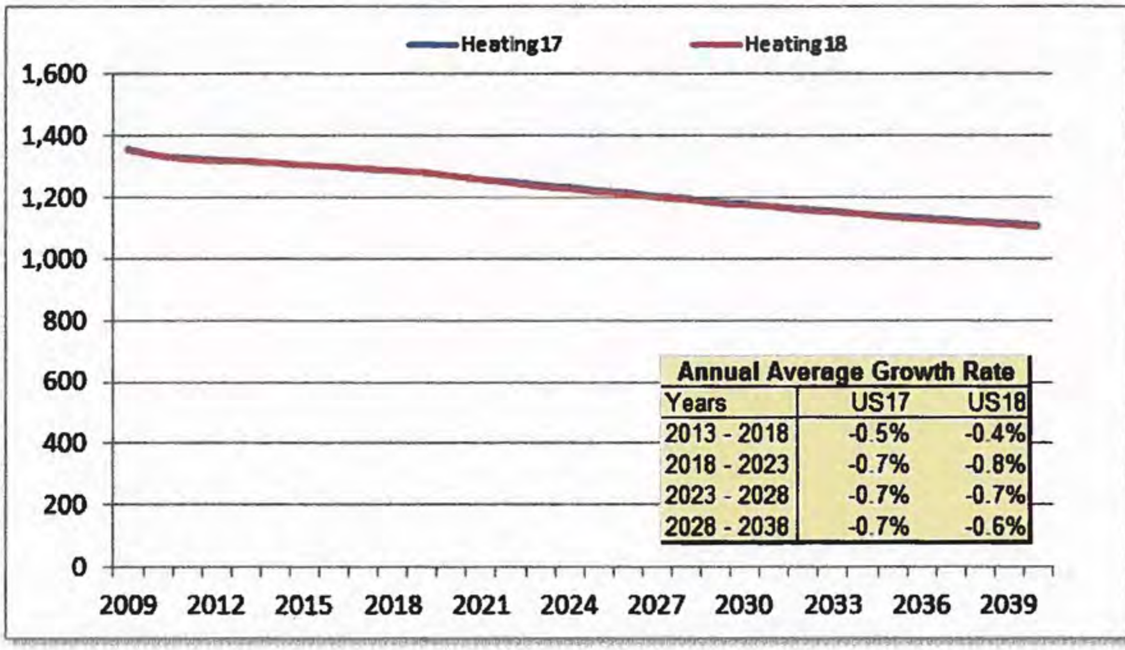
Over the next five years, the 2018 Mid-Atlantic intensity averages 1.7% decline compared with 1.4% average decline in 2017 forecast.

Another factor to note is that the end-use intensity projections include EIA's assumption on future utility efficiency efficiency (EE) spending. EIA intensity estimates also include projected behind the meter (BTM) solar adoption. EIA has provided us with their solar load forecast, so we have been able to back out EIA's solar load forecast from the SAE spreadsheets. EIA has said they will provide EE savings estimates later this summer; we will provide updated SAE 2018 spreadsheets that exclude EE savings estimates once we are able to process this data.

Electric Heating

Electric heating includes resistant electric heat, heat pumps, and furnace fan loads. Figure 4 shows the 2017 and 2018 heating intensity forecasts.

Figure 4: Heating Intensity Projections (kWh/household)



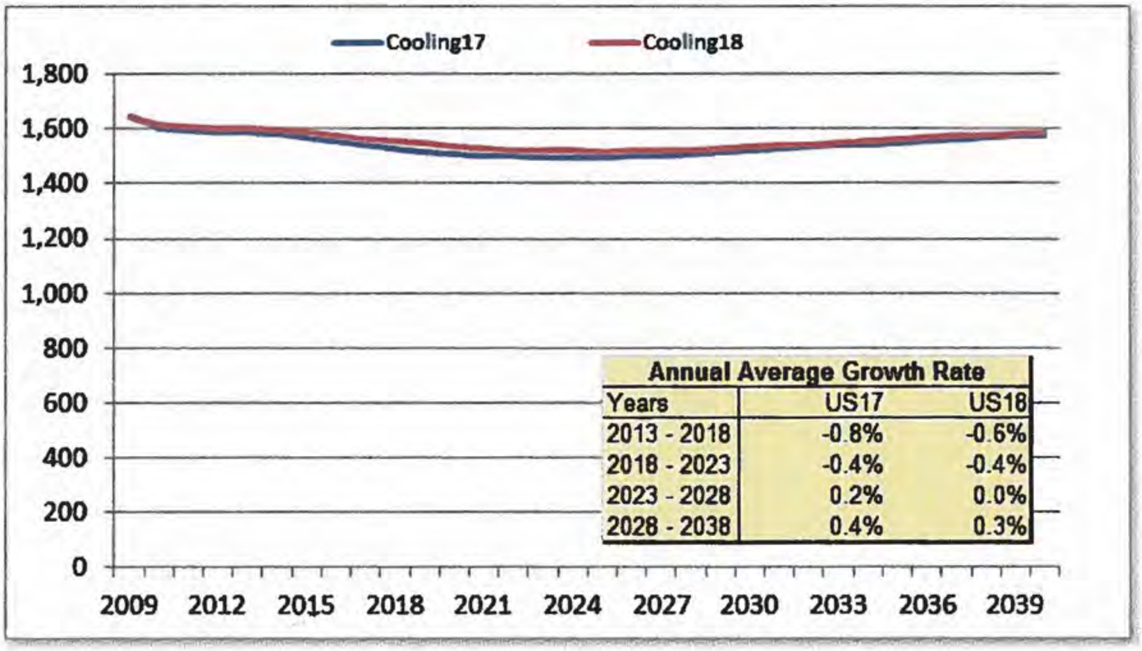
Annual Average Growth Rate		
Years	US17	US18
2013 - 2018	-0.5%	-0.4%
2018 - 2023	-0.7%	-0.8%
2023 - 2028	-0.7%	-0.7%
2028 - 2038	-0.7%	-0.6%

Total heating intensity forecast is only slightly different from the 2017 forecast.

Cooling

Cooling includes central and room air conditioning, and air-source heat pumps. There is also a small amount of cooling load from ground-source heat pumps. Figure 5 compares the 2017 and 2018 cooling intensity projections.

Figure 5: Cooling Intensity Projections (kWh/household)



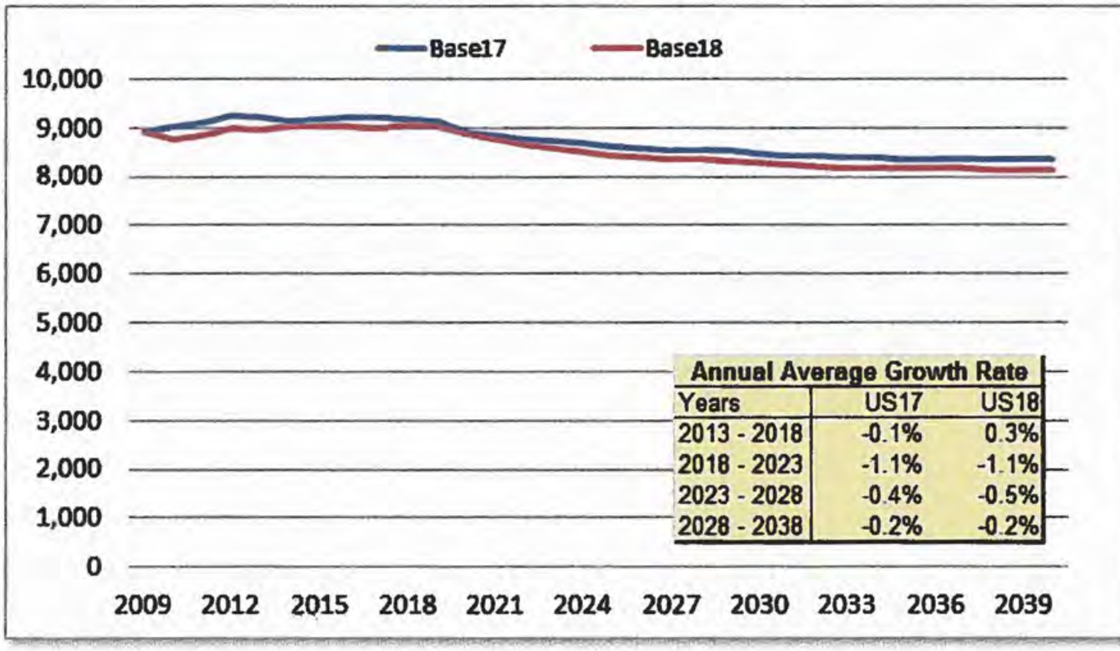
Annual Average Growth Rate		
Years	US17	US18
2013 - 2018	-0.8%	-0.6%
2018 - 2023	-0.4%	-0.4%
2023 - 2028	0.2%	0.0%
2028 - 2038	0.4%	0.3%

Near-term decline in cooling intensity is similar to last year's forecast; overall cooling efficiency increases faster than air conditioning saturation contributing to a -0.4% decline in average annual cooling intensity. Longer term, cooling intensity flattens out and shows some growth as improvements in air conditioning efficiency slows.

Electric Base Use

Electric base-use (loads which are not weather-sensitive) accounts for the largest share of residential electricity use. At the U.S. level, base-use accounts for 75% of residential electricity sales. Figure 6 compares base-use intensity projections.

Figure 6: Base Use Intensity (kWh/household)



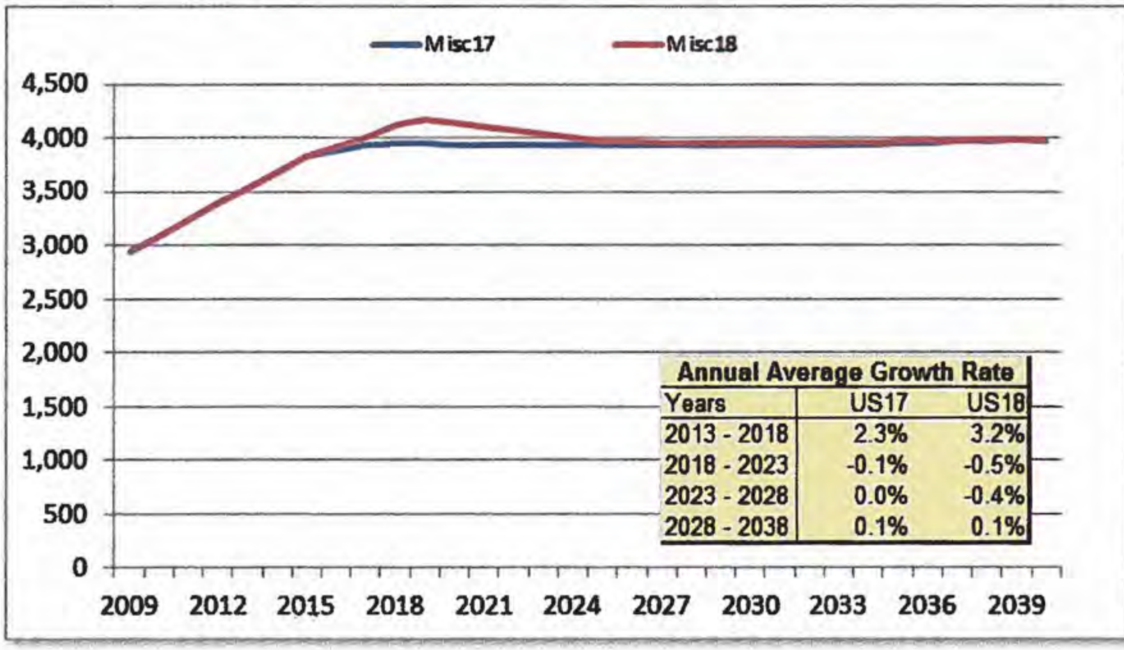
Annual Average Growth Rate		
Years	US17	US18
2013 - 2018	-0.1%	0.3%
2018 - 2023	-1.1%	-1.1%
2023 - 2028	-0.4%	-0.5%
2028 - 2038	-0.2%	-0.2%

The 2018 base-use intensity is slightly lower in terms of kWh per household than the 2017 forecast, but the forecasted growth rates are similar; average base-use intensity declines through the foreseeable future with the strongest decline over the next five years. While 2018 and 2017 total base-use intensity forecasts follow the same growth projectory, there are significant differences across some of the underlying end-uses. The largest differences are in miscellaneous, water heating, electric dryers, and lighting.

Miscellaneous

Miscellaneous is the largest end-use category accounting for roughly 25% of residential usage, and nearly half of base-use. Miscellaneous includes everything from pool pumps and security systems to smart phones and other plug-in devices. Figure 7 shows EIA's miscellaneous energy intensity forecasts for the current and prior-year forecasts.

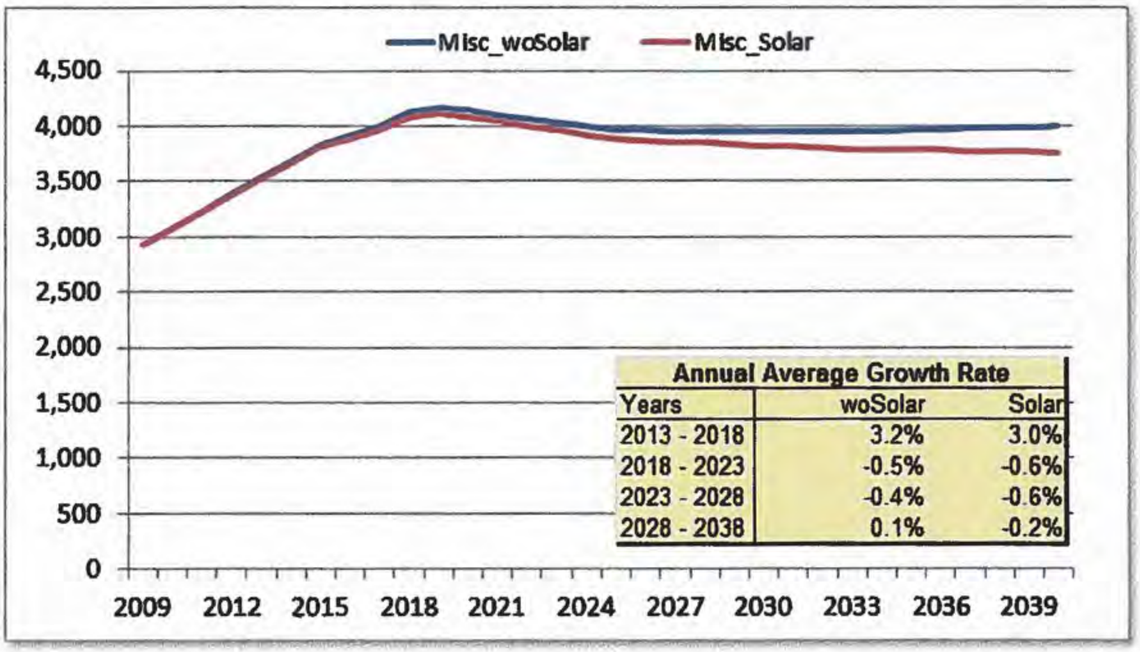
Figure 7: EIA Miscellaneous Intensity Projections (kWh/household)



The 2018 forecast shows an average annual decline of 0.5% through 2023 and continues to decline through 2028. In comparison the 2017 miscellaneous intensity forecast was largely flat through the forecast period. Changes in historical growth are a large contributor to differences in forecasted growth. The 2018 forecast shows 3.2% miscellaneous growth between 2013 and 2018 compared with 2.3% growth in the 2017 forecast. Ultimately, the 2018 and 2017 miscellaneous intensity projections reach the same point in 2027 at roughly 4,000 kWh per household.

The 2018 miscellaneous sales would decline even faster if BTM solar was not backed out of the forecast. Most of EIA's solar load impact rolls through the miscellaneous end-use. Figure 8 compares miscellaneous intensity with and without solar own-use generation.

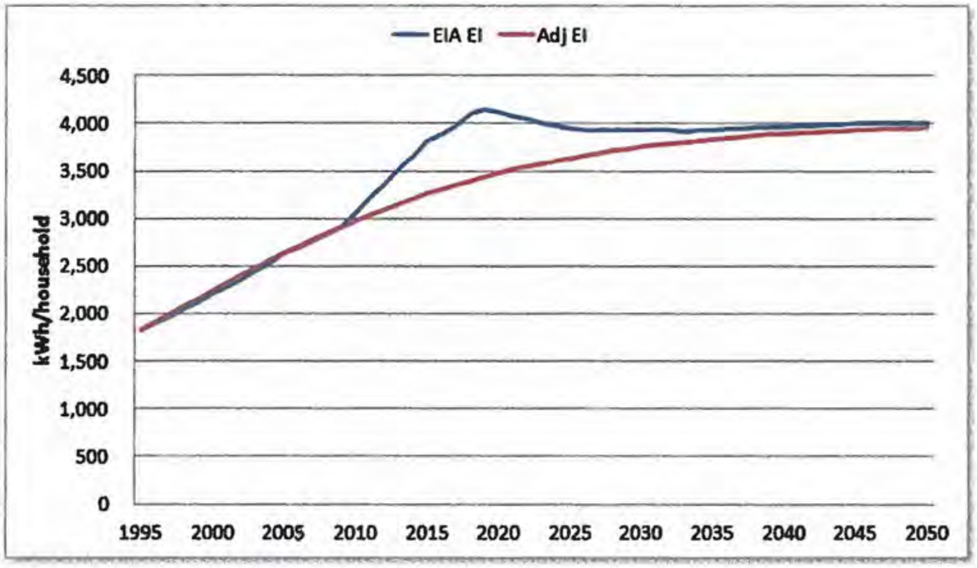
Figure 8: Miscellaneous Solar Adjustment (kWh/household)



Alternative Miscellaneous Intensity Curve

Miscellaneous sales growth like that associated with all new technologies can be expected to slow in the future as saturation growth of home miscellaneous end-uses slows down and efficiency improves. However, we are not entirely comfortable with the idea that miscellaneous energy use (which has been carrying most of residential usage growth for the last ten years) will turn negative over the near-term. Part of the decline may be attributed to embedded EE savings assumptions that we hope to back out later this summer. In the meantime, we have developed an adjusted miscellaneous intensity curve for each census division. The curve is based on a Bass Diffusion model that runs through the 2009 RECS estimate and ultimately reaches the long-term EIA intensity projection. Figure 9 compares adjusted against EIA's miscellaneous projections (excluding solar).

Figure 9: Adjusted Miscellaneous Usage Curve

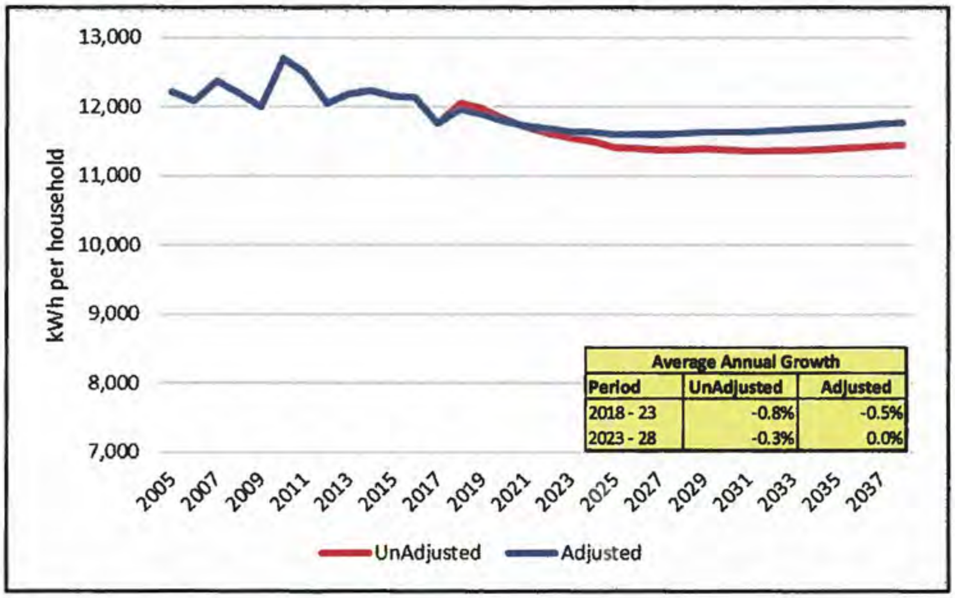


In contrast to EIA estimate, the adjusted miscellaneous intensity continues to increase over the entire forecast period but does so at a slowing rate. The curve fits historical data through 2009 but increases at a slower rate through 2018 than EIA's assumption. As this process impacts historical miscellaneous load estimates as well as the forecast, using the adjusted estimates in SAE models will change model coefficients.

In updating forecasts, we recommend comparing model results and forecasts using the unadjusted and adjusted miscellaneous intensity projections. Should you choose to use the adjusted miscellaneous curve, simply change the miscellaneous link in your MetrixND energy intensity Data Table to point to the "Misc_Adj" instead of "Misc".

Figure 10 shows predicted average use for the U.S. with the unadjusted and adjusted miscelleaneous intensities.

Figure 10: U.S. Average Use with Adjusted Miscellaneous Intensity



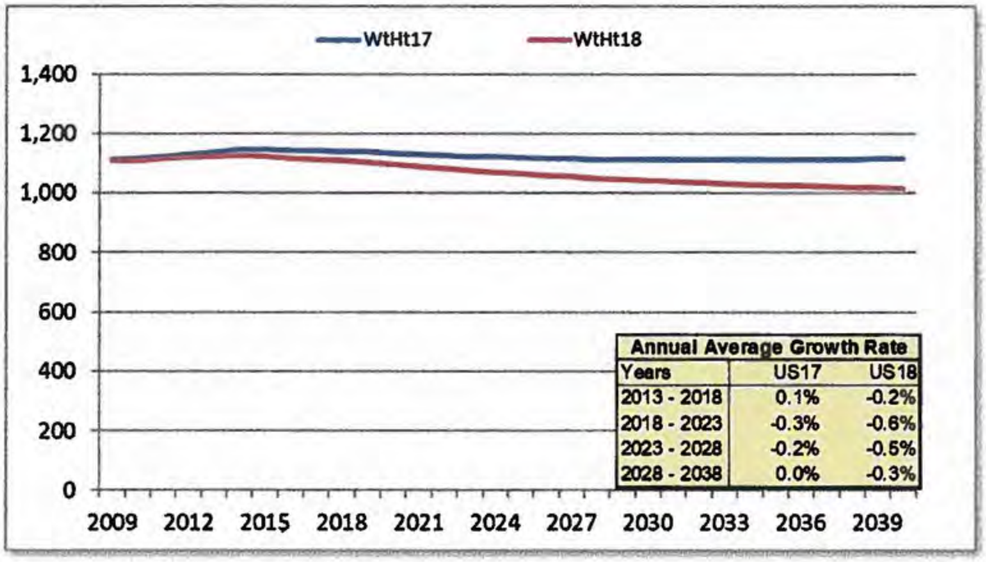
Average Annual Growth		
Period	UnAdjusted	Adjusted
2018 - 23	-0.8%	-0.5%
2023 - 28	-0.3%	0.0%

Using the curve-fitted intensity estimate, U.S. total intensity declines on average 0.5% (adjusted) over the next five years compared with -0.8% using EIA's miscellaneous (unadjusted) intensity projection. Between 2023 and 2028, adjusted miscellenous results in flat average use projection vs a 0.3% decline with EIA's projection.

Water Heating

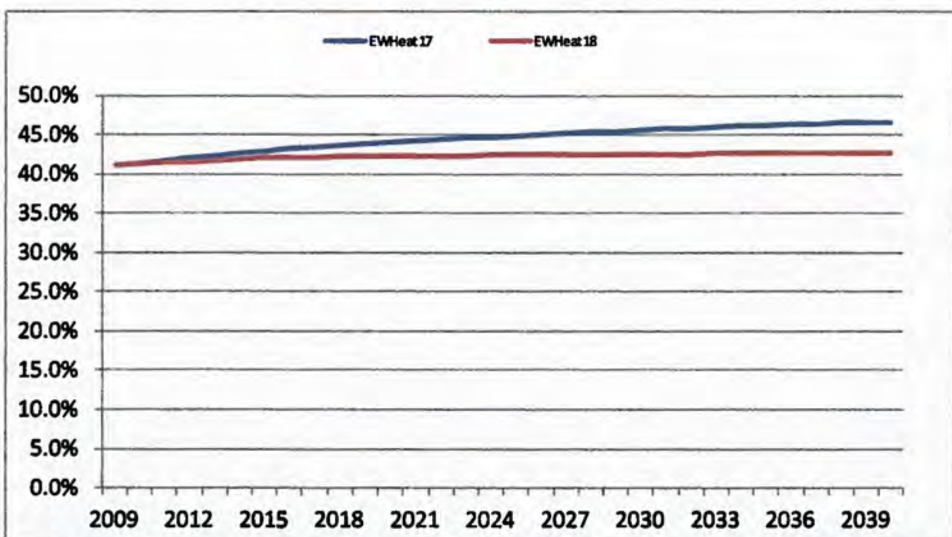
The electric water heating also declines at a faster rate than in the 2017 forecast. Figure 11 compares 2018 and 2017 forecasted water heating intensity.

Figure 11: Electric Water Heating Intensity (kWh/household)



For electric water heating it isn't differences in efficiency that drives the trends, but rather differences in saturation. The 2018 water heating saturation is lower because of lower natural gas prices which in turn results in higher saturation of gas water heating heating. Figure 12 compares electric water heating saturation.

Figure 12: Electric Water Heating Saturation

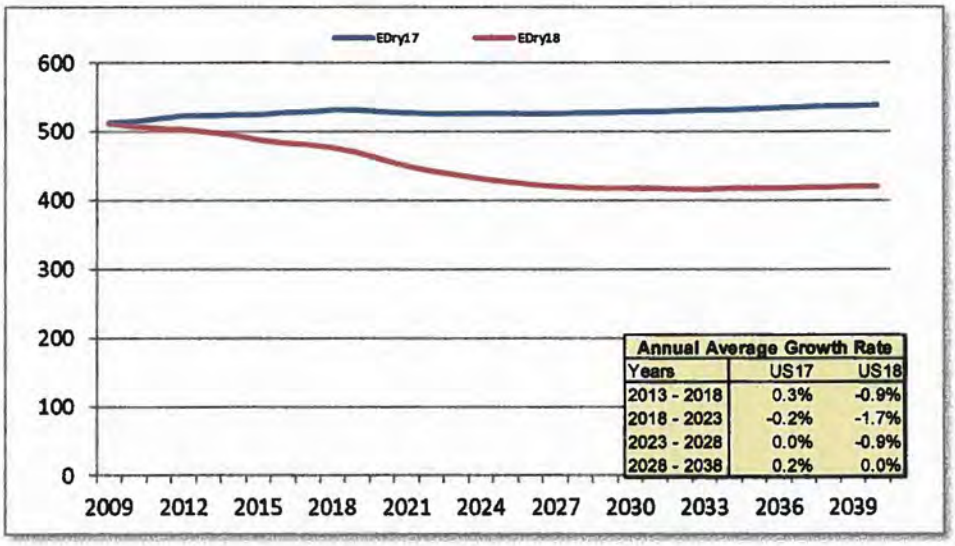


By 2023, electric water heating saturation is three precent lower in the 2018 forecast.

Electric Dryers

The 2018 electric dryer intensity is also lower than last year. Figure 13 compares 2017 and 2018 electric dryer intensities.

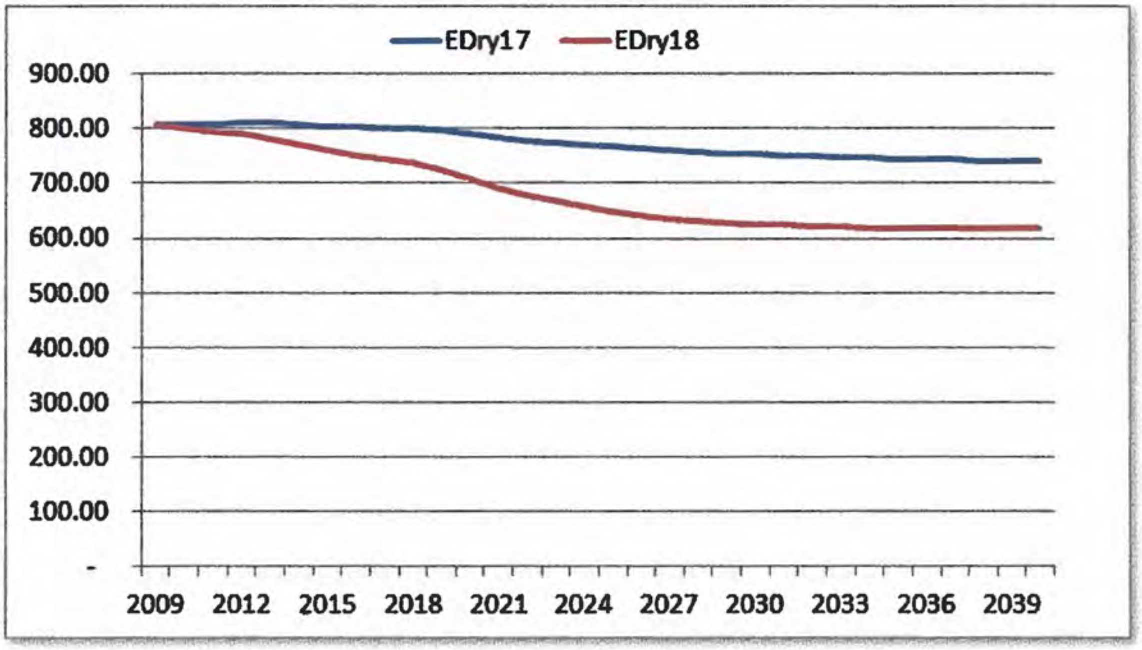
Figure 13: Electric Dryer Intensity (kWh/household)



While part of the difference is again due to lower electric dryer saturation, the bigger factor is assumed stronger gain in electric dryer efficiency.

Part of the difference is again due to lower natural gas prices that translate into lower electric and higher gas dryer saturations. The larger factor though is due to higher electric heat efficiency improvements; part of this may be driven by EIA's EE program assumption. Figure 14 compares electric dryer efficiency forecast.

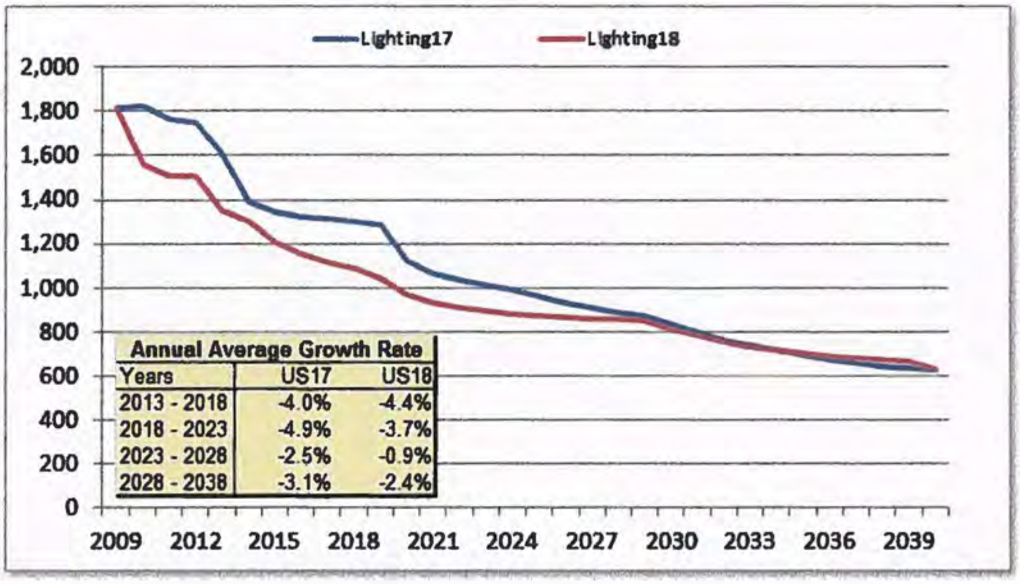
Figure 14: Electric Dryer Efficiency Projections (kWh/year)



Lighting

In 2018 residential lighting was adjusted to better account for historical shipment shares of general service incandescents, CFLs, and LEDs, as well as utility rebate incentives. Figure 15 shows lighting intensity projections.

Figure 15: Lighting Intensity (kWh/household)



Annual Average Growth Rate		
Years	US17	US18
2013 - 2018	-4.0%	-4.4%
2018 - 2023	-4.9%	-3.7%
2023 - 2028	-2.5%	-0.9%
2028 - 2038	-3.1%	-2.4%

The new forecast reflects faster upfront penetration of LED lighting with part of that due to utility lighting incentive programs. Because of earlier LED penetration, the sharp drop due where the new standards go into effect shown in the 2017 forecast are softened in the updated forecast. Lighting intensity flattens out after 2024 with lighting intensity reaching 800 kWh per household by 2030. Slower decline in lighting intensity largely compensates for stronger intensity declines in miscellaneous, water heating, and electric dryers.

Changes from 2017 – Natural Gas

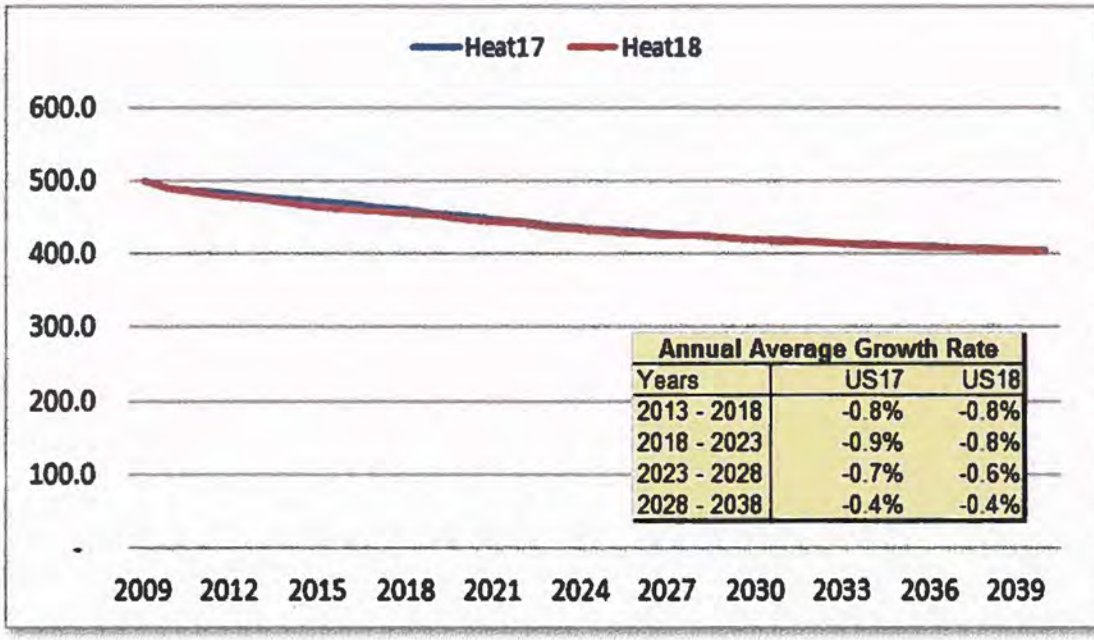
Space heating and water heating account for 95% of residential natural gas usage, with cooking and clothes dryers accounting for the remainder. At the U.S. level, roughly 50% of households have gas space and water heating. The share of homes with gas space heat has been relatively constant and is expected to increase just slightly over the next 20 years.

Gas Heating

Over the last 10 years, there have been significant improvements in heating system efficiency. With a relatively flat saturation, gas heating use declines as improvements in efficiency continue.

Residential gas heat intensity has averaged 0.7% decline over the last 10 years. Figure 16 compares the 2017 and 2018 gas heating intensity projections.

Figure 16: Heating Intensity (Therms/household)

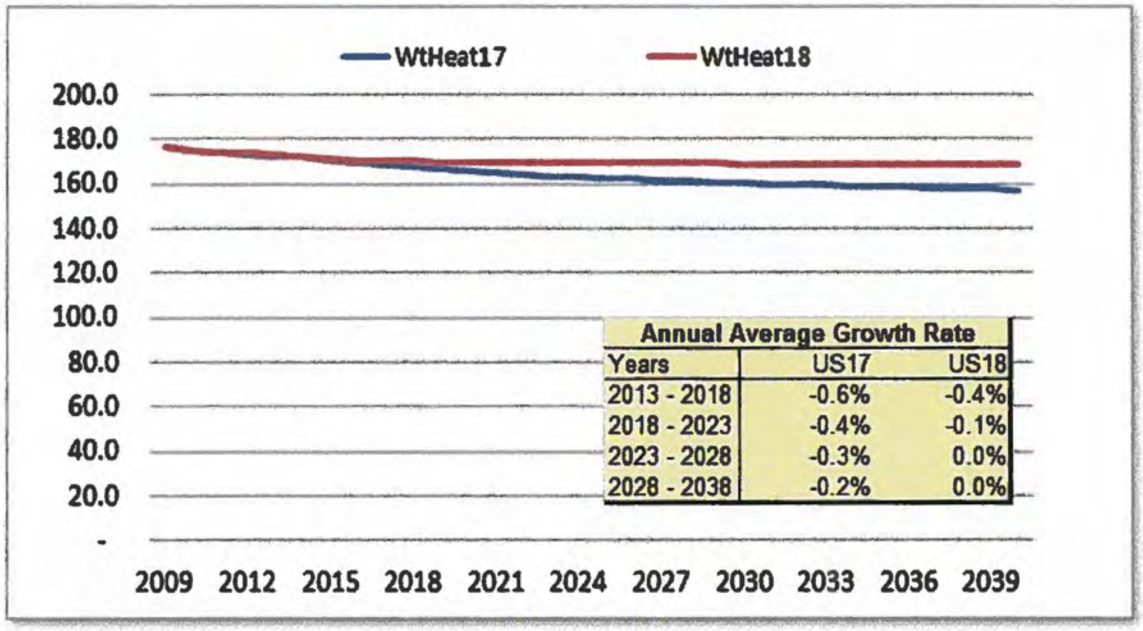


There is little difference in heating usage between the two forecasts.

Water Heating

Water heating is the second largest gas end-use, accounting for approximately 30% of residential natural gas usage. As with furnaces and gas boilers, water heaters have seen significant improvements in energy efficiency. Because efficiency has been increasing while saturation has been flat to declining, gas water heating intensity has also been declining. Figure 17 shows the 2017 and 2018 gas water heating intensity forecast.

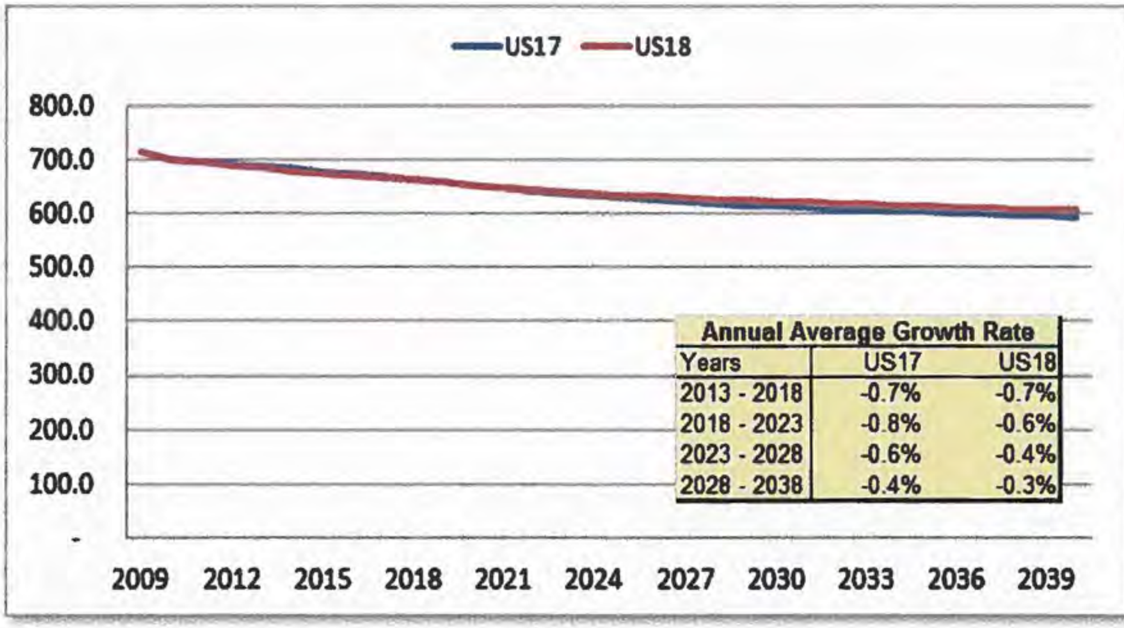
Figure 17: Gas Water Heating Intensity (Therms/household)



The 2017 gas water heating intensities are projected to be largely flat throughout the forecast period due to flat versus declining saturation in 2017.

Gas dryer and cooking energy intensities also decline through the forecast horizon. When all gas appliances are aggregated, total residential gas intensity averages 0.7% annual decline over the next 10 years. This is not significantly different than the previous 10 years and is slightly higher than 2017 forecast. Figure 18 shows total residential gas intensity forecast.

Figure 18: Total Residential Gas Intensity (Therms/household)



Annual Average Growth Rate		
Years	US17	US18
2013 - 2018	-0.7%	-0.7%
2018 - 2023	-0.8%	-0.6%
2023 - 2028	-0.6%	-0.4%
2028 - 2038	-0.4%	-0.3%

Summary

EIA's 2018 electric end-use efficiency projections coupled with lower saturations for end-uses that competed with natural gas results in EIA's lowest end-use intensity projections to date. For those that incorporate the end-use intensities into residential SAE models you will likely see lower residential sales forecasts than in prior years. The lower intensities can partly be mitigated by using the adjusted miscellaneous intensity incorporated in the SAE spreadsheets. The 2018 projected intensities will likely be adjusted upwards once we are able to back out the EE program savings assumptions. We plan on a second 2018 release hopefully by the end of the summer.

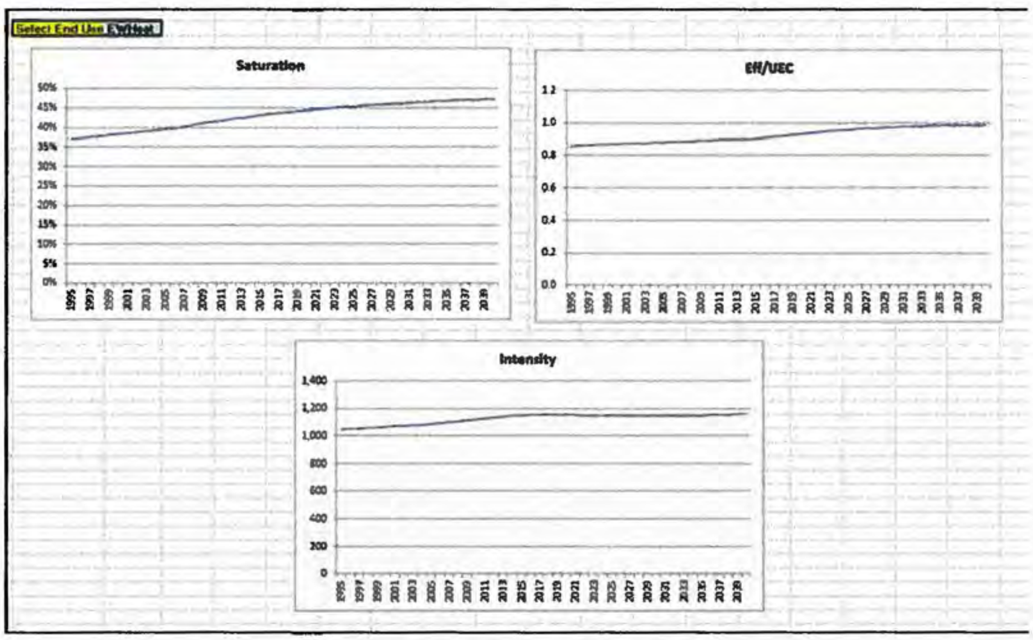
In 2019 we are likely to see another significant change in end-use intensities as EIA updates the long-term forecast to based on the 2015 RECS. This will also require a major effort on our part to integrate past RECS surveys and estimated stock efficiency into a new historical set of saturation, efficiency, and intensites. Given the coming changes, and our concerns with the current 2018 indices, it would not be unreasonable to continue using the 2017 indices in any near-term forecast development work.

Appendix A: Using the SAE Spreadsheets

Updates to the SAE Spreadsheets

Itron continually works to simplify and improve the SAE spreadsheets to allow analysts to view end-use intensity trends, to understand how the indices are calculated, and to customize the SAE inputs (such as end-use saturations and starting UEC) to their own service area. Last year, Itron added a new "graph" tab that allows the analyst to select an end-use and graph the end-use saturation, efficiency/UEC, and calculated intensity. Figure 19 shows this feature for electric water heaters.

Figure 19: SAE Spreadsheet End-Use Graph - Electric Water Heat



SAE Spreadsheet Organization

The SAE spreadsheets are organized to allow the analyst to calibrate end-use intensities to a specific utility service area organization where service area specific saturation and UEC estimates are available. The spreadsheet tabs include:

- **Definitions** provides descriptive information about end-uses, units and brief descriptions of the other worksheets.
- **EIAData** contains EIA efficiency, consumption, equipment stock, household, floor space and price projections.
- **Calibration** provides base year usage information. It can also be used to customize the spreadsheet to the user's service territory. Figure 20 shows the layout of the Calibration worksheet.

Figure 20: Calibration Worksheet

	A	B	C	D	E	F	G	H	I	J	K
1	Base Year (2009)	EFurn	HPHeat	GHPHeat	SecHt	CAC	HPCool	GHPCool	RAC	EWHeat	ECook
2	Consumption (mmBtu)	295,156,965	49,006,093	3,298,852	60,466,462	469,614,726	92,426,664	4,189,994	68,043,412	428,267,637	104,815,834
3	Equipment Stock (units)	29,626,185	9,099,838	699,168	28,312,038	61,707,187	9,099,838	699,168	49,101,682	46,763,693	68,137,629
4	UEC (kWh/unit)	2,920	1,578	1,383	626	2,230	2,977	1,756	406	2,684	451
5	Share (%)	26.0%	8.0%	0.6%	23.4%	54.2%	8.0%	0.6%	43.1%	41.1%	59.9%
6	Raw Intensity (kWh/year)	760	126	8	147	1,209	238	11	175	1,103	270
7	Model-Scaled Intensity (kWh/year)	760	126	8	147	1,209	238	11	175	1,103	270
8											
9	Observed Use Per Customer (kWh/year)	11,909									
10	Adjustment Factor	1.010									
11	Adjusted Intensity (kWh/year)	768	127	9	148	1,222	240	11	177	1,114	273
12											
13	XHeat	1.000									
14	XCool	1.000									
15	XOther	1.000									
16											

Base-year use-per-customer (kWh) for the utility service area is depicted in Row 9 and can be used to calibrate the spreadsheet to the user's service territory. To do this, substitute your weather-normalized average use for the Census Division average-use in Cell B9.

In additional to basic calibration to observed usage, in 2017 we have also added another layer of calibration to better tailor the regional data to utility-specific conditions. In order to get better starting estimates of electric usage by end-use, we have utilized MetrixND models to "true up" EIA estimates to the regions. You can do this on the utlity level by substituting the adjustment factors in cells B13-15 with estimated coefficients on SAE variables in your residential model. Figure 21 below provides an example.

Figure 21: Model-Based Calibration

	A	B	C	D	E	F	G	H	I	J	K
1	Base Year (2009)	EFurn	HPHeat	GHPHeat	SecHt	CAC	HPCool	GHPCool	RAC	EWHeat	ECook
2	Consumption (mmBtu)	295,156,965	49,006,093	3,298,852	60,466,462	469,614,726	92,426,664	4,189,994	68,043,412	428,267,637	104,815,834
3	Equipment Stock (units)	29,626,185	9,099,838	699,168	28,312,038	61,707,187	9,099,838	699,168	49,101,682	46,763,693	68,137,629
4	UEC (kWh/unit)	2,920	1,578	1,383	626	2,230	2,977	1,756	406	2,684	451
5	Share (%)	26.0%	8.0%	0.6%	23.4%	54.2%	8.0%	0.6%	43.1%	41.1%	59.9%
6	Raw Intensity (kWh/year)	760	126	8	147	1,209	238	11	175	1,103	270
7	Model-Scaled Intensity (kWh/year)	1,853	308	21	358	2,389	470	21	346	677	166
8											
9	Observed Use Per Customer (kWh/year)	11,909									
10	Adjustment Factor	0.999									
11	Adjusted Intensity (kWh/year)	1,852	307	21	357	2,387	470	21	346	677	166
12											
13	XHeat	2.438									
14	XCool	1.975									
15	XOther	0.614									
16											

In this case, model-based calibration adjusts heating and cooling starting year usage up based on model coefficients estimated from observed use per customer data. Other usage is adjusted downward.

Resulting end-use intensities are written to the Intensities tab. MetrixND project files can link to the Intensities tab as the source-data for the constructing of SAE model variables.

StructuralVars

This worksheet contains data about the size of homes and their building shell efficiencies. The results of the calculations on this tab are used in the development of energy intensities for heating and cooling end-uses.

Analysts can substitute local household and floor space estimates for the regional estimates to reflect local conditions in the final energy intensities. Total floor space can be modified in Column E and number of households in Column I.

Shares

The Shares tab contains historical saturation estimates and forecasts developed by the EIA. Data from appliance saturation surveys can be used to modify the default saturations. Depending on data availability, these changes can either shift the projections up or down (one survey) or modify the growth rate in the trends (two or more surveys).

Efficiencies

The Efficiencies tab provides historical and forecasted end-use efficiency. UEC estimates are used as a proxy for efficiency where specific technology efficiency data (as central air conditioner SEER) are not available. Efficiency trends can also be modified to reflect the utility service area. As a practical matter however, average efficiency for most equipment varies little between regions.

Intensities

Intensities are per-household end-use energy estimate derived from combining end-use saturation, efficiency, and starting UEC. If the user changes saturation and/or efficiency, the changes are reflected in the end-use intensity calculations.

MonthlyMults

This tab provides seasonal multipliers for non-HVAC end-uses. This allows us to accurately gauge seasonal usage for such non weather-sensitive end-uses as water heating, refrigeration and lighting.

Graphs

The Graphs tab provides an interface to select an end-use and view historical and projected end-use saturation, efficiency (or UEC where an efficiency measure is not available) and resulting end-use intensity.

EV

Electric vehicle load is added to the base (other) end-use in the SAE model. Input data rows are highlighted in red and include:

- **Households** - Historical and forecasted number of households (column B)
- **EVSold** - Number of EV vehicles sold in any given year (column C)
- **EVDecay** - Number of EV vehicles removed (column D)
- **AnnualMiles** - Annual average miles driven (column G)
- **MilePerKwh** - Average vehicle efficiency (column H)

Additional columns include:

- **EVStock** - Calculated as the sum of all new purchases minus vehicle decay (column E).
- **Share** - The share of households with EVs (column F), calculated as *EVStock / Households*.

- **UEC** - The Unit Energy Consumption (kWh) for those households that own an EV. Calculated as the number of miles driven divided by the average vehicle miles per kWh (column I).
- **ShareUEC** - Use per household (column K), calculated by multiplying the vehicle UEC and the share of households that own an EV. The resulting annual EV energy intensity is on a kWh per household basis and can be added to the base or *other use index* in the SAE model.

PV

The SAE spreadsheets also include a worksheet for calculating PV (photovoltaic) energy impacts. Input data rows are highlighted in red and include:

- **Households** - Historical and forecasted Households or customers (column B)
- **PVInstalls** - Number of new PV installations (column C)
- **AvgPVSize** - Average PV kW capacity (column E)
- **PVDecayKW** - PV capacity decay in kW (column G)
- **CapacityFactor** - Capacity Factor (column I)

Additional columns include:

- **PVStockKW** - Estimated PV kW capacity (column H), calculated by summing current and all past PV installed capacity and subtracting the decay, calculated as:

$$(PVInstalls \times AvgPVSize) - PVDecayKW$$

- **PVEnergy** - PV MWh (column J) is derived by applying the capacity factor to the PV Capacity Stock, calculated as:

$$(PVStockKW \times 8760 \times CapacityFactor)/1000$$

- **ShareUEC** - Final PV energy intensity (column K) is derived by dividing *PVEnergy* by total number of households. The estimate is negative, as it represents a load reduction.

Appendix B: Residential SAE Modeling Framework

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. Econometric models are well suited to identifying historical trends and to projecting these trends into the future. In contrast, end-use models are able to identify and isolate the end-use factors that are driving energy use. By incorporating end-use structure into an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to this approach.

- The equipment efficiency and saturation trends, dwelling square footage, and thermal integrity changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast. This provides a strong bridge between the two forecasts.
- By explicitly incorporating trends in equipment saturations, equipment efficiency, dwelling square footage, and thermal integrity levels, it is easier to explain changes in usage levels and changes in weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be incorporated into the final model.

This section describes this approach, the associated supporting SAE spreadsheets, and the *MetrixND* project files that are used in the implementation. The main source of the SAE spreadsheets is the 2017 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

Statistically Adjusted End-Use Modeling Framework

The statistically adjusted end-use modeling framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$), and other equipment ($Other_{y,m}$). Formally,

$$\mathrm{USE}_{y,m} = \mathrm{Heat}_{y,m} + \mathrm{Cool}_{y,m} + \mathrm{Other}_{y,m} \qquad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$\mathrm{USE}_{m} = a + b_1 \times \mathrm{XHeat}_m + b_2 \times \mathrm{XCool}_m + b_3 \times \mathrm{XOther}_m + \varepsilon_m \qquad (2)$$

$XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, dwelling data, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

Constructing XHeat

As represented in the SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days
- Heating equipment saturation levels
- Heating equipment operating efficiencies
- Average number of days in the billing cycle for each month
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier:

$$XHeat_{y,m} = HeatIndex_{y,m} \times HeatUse_{y,m} \qquad (3)$$

Where:

- $XHeat_{y,m}$ is estimated heating energy use in year (y) and month (m)
- $HeatIndex_{y,m}$ is the monthly index of heating equipment
- $HeatUse_{y,m}$ is the monthly usage multiplier

The heating equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Given a set of fixed weights, the index will change over time with changes in equipment saturations (*Sat*), operating efficiencies (*Eff*), building structural index (*StructuralIndex*), and energy prices. Formally, the equipment index is defined as:

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ Eff_y^{Type} \right)}{\left(Sat_{09}^{Type} \Big/ Eff_{09}^{Type} \right)} \tag{4}$$

The *StructuralIndex* is constructed by combining the EIA's building shell efficiency index trends with surface area estimates, and then it is indexed to the 2009 value:

$$StructuralIndex_y = \frac{BuildingShellEfficiencyIndex_y \times SurfaceArea_y}{BuildingShellEfficiencyIndex_{09} \times SurfaceArea_{09}} \tag{5}$$

The *StructuralIndex* is defined on the *StructuralVars* tab of the SAE spreadsheets. Surface area is derived to account for roof and wall area of a standard dwelling based on the regional average square footage data obtained from EIA. The relationship between the square footage and surface area is constructed assuming an aspect ratio of 0.75 and an average of 25% two-story and 75% single-story. Given these assumptions, the approximate linear relationship for surface area is:

$$SurfaceArea_y = 892 + 1.44 \times Footage_y \tag{6}$$

In Equation 4, 2009 is used as a base year for normalizing the index. As a result, the ratio on the right is equal to 1.0 in 2009. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2009 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{09}^{Type}}{HH_{09}} \times HeatShare_{09}^{Type} \qquad (7)$$

In the SAE spreadsheets, these weights are referred to as *Intensities* and are defined on the *EIAData* tab. With these weights, the *HeatIndex* value in 2009 will be equal to estimated annual heating intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

For electric heating equipment, the SAE spreadsheets contain two equipment types: electric resistance furnaces/room units and electric space heating heat pumps. Examples of weights for these two equipment types for the U.S. are given in Table 1.

Table 1: Electric Space Heating Equipment Weights

Equipment Type	Weight (kWh)
Electric Resistance Furnace/Room units	760
Electric Space Heating Heat Pump	126

Data for the equipment saturation and efficiency trends are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for electric space heating heat pumps are given in terms of Heating Seasonal Performance Factor [BTU/Wh], and the efficiencies for electric furnaces and room units are estimated as 100%, which is equivalent to 3.41 BTU/Wh.

Price Impacts. In the 2007 version of the SAE models and thereafter, the Heat Index has been extended to account for the long-run impact of electric and natural gas prices. Since the Heat Index represents changes in the stock of space heating equipment, the price impacts are modeled to play themselves out over a 10-year horizon. To introduce price effects, the Heat Index as defined by

Equation 4 above is multiplied by a 10-year moving-average of electric and gas prices. The level of the price impact is guided by the long-term price elasticities:

$$HeatIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \big/ Eff_y^{Type} \right)}{\left(Sat_{09}^{Type} \big/ Eff_{09}^{Type} \right)} \times \\ \left(TenYearMovingAverageElectric\Pr ice_{y,m}\right)^{\phi} \times \left(TenYearMovingAverageGas\Pr ice_{y,m}\right)^{\gamma} \tag{8}$$

Since the trends in the Structural index (the equipment saturations and efficiency levels) are provided exogenously by the EIA, the price impacts are introduced in a multiplicative form. As a result, the long-run change in the Heat Index represents a combination of adjustments to the structural integrity of new homes, saturations in equipment and efficiency levels relative to what was contained in the base EIA long-term forecast.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, prices, and billing days. The estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{WgtHDD_{y,m}}{HDD_{09}}\right) \times \left(\frac{HHSize_y}{HHSize_{09}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{09}}\right)^{0.20} \\ \times \left(\frac{Elec\Pr ice_{y,m}}{Elec\Pr ice_{09,7}}\right)^{\lambda} \times \left(\frac{Gas\Pr ice_{y,m}}{Gas\Pr ice_{09,7}}\right)^{\kappa} \tag{9}$$

Where:

- *WgtHDD* is the weighted number of heating degree days in year (y) and month (m). This is constructed as the weighted sum of the current month's HDD and the prior month's HDD. The weights are 75% on the current month and 25% on the prior month.
- *HDD* is the annual heating degree days for 2009
- *HHSize* is average household size in a year (y)
- *Income* is average real income per household in year (y)
- *ElecPrice* is the average real price of electricity in month (m) and year (y)
- *GasPrice* is the average real price of natural gas in month (m) and year (y)

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to 1.0 in the base year (2009). The first two terms, which involve billing days and heating degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will reflect changes in the economic drivers, as transformed through the end-use elasticity parameters. The price impacts captured by the Usage equation represent short-term price response.

Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days
- Cooling equipment saturation levels
- Cooling equipment operating efficiencies
- Average number of days in the billing cycle for each month
- Thermal integrity and footage of homes
- Average household size, household income, and energy prices

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$XCool_{y,m} = CoolIndex_y \times CoolUse_{y,m} \tag{10}$$

Where

- $XCool_{y,m}$ is estimated cooling energy use in year (y) and month (m)
- $CoolIndex_y$ is an index of cooling equipment
- $CoolUse_{y,m}$ is the monthly usage multiplier

As with heating, the cooling equipment index is defined as a weighted average across equipment types of equipment saturation levels normalized by operating efficiency levels. Formally, the cooling equipment index is defined as:

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ Eff_y^{Type} \right)}{\left(Sat_{09}^{Type} \Big/ Eff_{09}^{Type} \right)} \tag{11}$$

Data values in 2009 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2009. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2009 level. This will be counteracted by higher efficiency levels, which will drive the index downward. The weights are defined as follows.

$$Weight^{Type} = \frac{Energy_{09}^{Type}}{HH_{09}} \times CoolShare_{09}^{Type} \tag{12}$$

In the SAE spreadsheets, these weights are referred to as *Intensities* and are defined on the *EIAData* tab. With these weights, the *CoolIndex* value in 2009 will be equal to estimated annual cooling intensity per household in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

For cooling equipment, the SAE spreadsheets contain three equipment types: central air conditioning, space cooling heat pump, and room air conditioning. Examples of weights for these three equipment types for the U.S. are given in Table 2.

Table 2: Space Cooling Equipment Weights

Equipment Type	Weight (kWh)
Central Air Conditioning	1,209
Space Cooling Heat Pump	238
Room Air Conditioning	175

The equipment saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets. The efficiency for space cooling heat pumps and central air conditioning (A/C) units are given in terms of Seasonal Energy Efficiency Ratio [BTU/Wh], and room A/C units efficiencies are given in terms of Energy Efficiency Ratio [BTU/Wh].

Price Impacts. In the 2007 SAE models and thereafter, the Cool Index has been extended to account for changes in electric and natural gas prices. Since the Cool Index represents changes in the stock of space heating equipment, it is anticipated that the impact of prices will be long-term in nature. The Cool Index as defined Equation 11 above is then multiplied by a 10-year moving average of electric and gas prices. The level of the price impact is guided by the long-term price elasticities.

$$CoolIndex_y = StructuralIndex_y \times \sum_{Type} Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ Eff_y^{Type} \right)}{\left(Sat_{09}^{Type} \Big/ Eff_{09}^{Type} \right)} \times \left(TenYearMovingAverageElectric\Pr ice_{y,m}\right)^{\phi} \times \left(TenYearMovingAverageGas\Pr ice_{y,m}\right)^{\gamma} \qquad (13)$$

Since the trends in the Structural index, equipment saturations and efficiency levels are provided exogenously by the EIA, price impacts are introduced in a multiplicative form. The long-run change in the Cool Index represents a combination of adjustments to the structural integrity of new homes, saturations in equipment and efficiency levels. Without a detailed end-use model, it is not possible to isolate the price impact on any one of these concepts.

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, household size, income levels, and prices. The estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{WgtCDD_{y,m}}{CDD_{09}}\right) \times \left(\frac{HHSize_y}{HHSize_{09}}\right)^{0.25} \times \left(\frac{Income_y}{Income_{09}}\right)^{0.20} \times \left(\frac{Elec\Pr ice_{y,m}}{Elec\Pr ice_{09}}\right)^{\lambda} \times \left(\frac{Gas\Pr ice_{y,m}}{Gas\Pr ice_{09}}\right)^{\kappa} \qquad (14)$$

Where:

- *WgtCDD* is the weighted number of cooling degree days in year (*y*) and month (*m*). This is constructed as the weighted sum of the current month's CDD and the prior month's CDD. The weights are 75% on the current month and 25% on the prior month.
- *CDD* is the annual cooling degree days for 2009.

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year (2009). The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will change to reflect changes in the economic driver changes.

Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Appliance and equipment saturation levels
- Appliance efficiency levels
- Average number of days in the billing cycle for each month
- Average household size, real income, and real prices

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherEqpIndex_{y,m} \times OtherUse_{y,m} \tag{15}$$

The first term on the right hand side of this expression ($OtherEqpIndex_y$) embodies information about appliance saturation and efficiency levels and monthly usage multipliers. The second term (*OtherUse*) captures the impact of changes in prices, income, household size, and number of billing-days on appliance utilization.

End-use indices are constructed in the SAE models. A separate end-use index is constructed for each end-use equipment type using the following function form.

$$ApplianceIndex_{y,m} = Weight^{Type} \times \frac{\left(Sat_y^{Type} \Big/ \frac{1}{UEC_y^{Type}} \right)}{\left(Sat_{09}^{Type} \Big/ \frac{1}{UEC_{09}^{Type}} \right)} \times MoMult_m^{Type} \times \tag{16}$$
$$(TenYearMovingAverageElectric\Pr ice)^{\lambda} \times (TenYearMovingAverageGas\Pr ice)^{\kappa}$$

Where:

- *Weight* is the weight for each appliance type
- *Sat* represents the fraction of households, who own an appliance type
- $MoMult_m$ is a monthly multiplier for the appliance type in month (m)
- *Eff* is the average operating efficiency the appliance
- *UEC* is the unit energy consumption for appliances

This index combines information about trends in saturation levels and efficiency levels for the main appliance categories with monthly multipliers for lighting, water heating, and refrigeration.

The appliance saturation and efficiency trends data are presented on the *Shares* and *Efficiencies* tabs of the SAE spreadsheets.

Further monthly variation is introduced by multiplying by usage factors that cut across all end uses, constructed as follows:

$$ApplianceUse_{y,m} = \left(\frac{BDays_{y,m}}{30.44}\right) \times \left(\frac{HHSize_y}{HHSize_{09}}\right)^{0.46} \times \left(\frac{Income_y}{Income_{09}}\right)^{0.10} \times \left(\frac{ElecPrice_{y,m}}{ElecPrice_{09}}\right)^{\phi} \times \left(\frac{GasPrice_{y,m}}{GasPrice_{09}}\right)^{\lambda} \tag{17}$$

The index for other uses is derived then by summing across the appliances:

$$OtherEqpIndex_{y,m} = \sum_k ApplianceIndex_{y,m} \times ApplianceUse_{y,m} \tag{18}$$

Supporting Spreadsheets and MetrixND Project Files

The SAE approach described above has been implemented for each of the nine Census Divisions. A mapping of states to Census Divisions is presented in Figure 22. This section describes the contents of each file and a procedure for customizing the files for specific utility data. A total of 18 files are provided. These files are listed in Table 3.

Figure 22: Mapping of States to Census Divisions

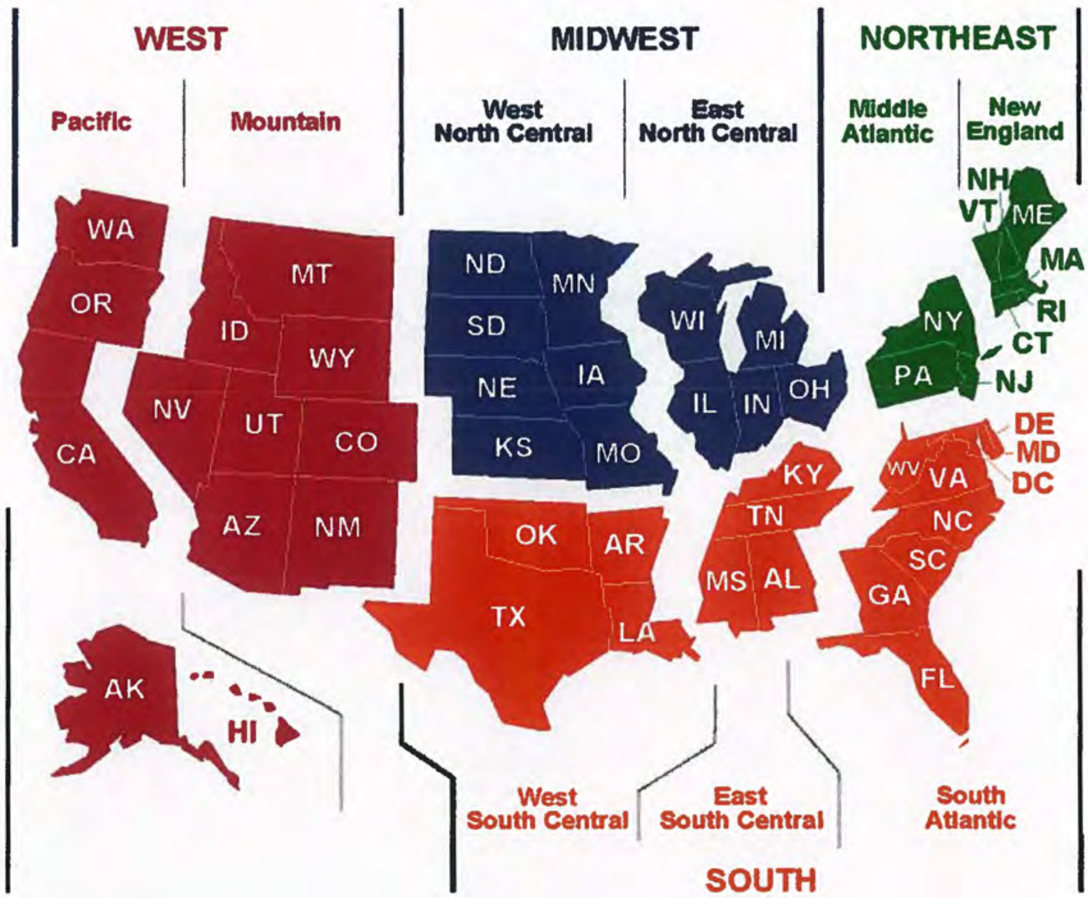


Table 3: List of SAE Files

Spreadsheet	*MetrixND* Project File
NewEngland.xls	SAE_NewEngland.ndm
MiddleAtlantic.xls	SAE_MiddleAtlantic.ndm
EastNorthCentral.xls	SAE_EastNorthCentral.ndm
WestNorthCentral.xls	SAE_WestNorthCentral.ndm
SouthAtlantic.xls	SAE_SouthAltantic.ndm
EastSouthCentral.xls	SAE_EastSouthCentral.ndm
WestSouthCentral.xls	SAE_WestSouthCentral.ndm
Mountain.xls	SAE_Mountain.ndm
Pacific.xls	SAE_Pacific.ndm

As defaults, the SAE spreadsheets include regional data, but utility data can be entered to generate the *Heat*, *Cool*, and *Other* equipment indices used in the SAE approach. The *MetrixND* project files link to the data in these spreadsheets. These project files calcualte the end-use *Usage* variables are constructed and the estimated SAE models.

Each of the nine SAE spreadsheets contains the following tabs:

- **Definitions** - Contains equipment, end use, worksheet, and Census Division definitions.
- **Intensities** - Calculates the annual equipment indices.
- **Shares** - Contains historical and forecasted equipment shares. The default forecasted values are provided by the EIA. The raw EIA projections are provided on the *EIAData* tab.
- **Efficiencies** - Contains historical and forecasted equipment efficiency trends. The forecasted values are based on projections provided by the EIA. The raw EIA projections are provided on the *EIAData* tab.
- **StructuralVars** - Contains historical and forecasted square footage, number of households, building shell efficiency index, and calculation of structural variable. The forecasted values are based on projections provided by the EIA.
- **Calibration** - This tab contains calculations of the base year *Intensity* values used to weight the equipment indices.
- **EIAData** - Contains the raw forecasted data provided by the EIA.
- **MonthlyMults** - Contains monthly multipliers that are used to spread the annual equipment indices across the months.
- **EV** - Worksheet for incorporating electric vehicle (EV) impacts.
- **PV** - Worksheet for incorporating photovoltaic battery (PV) impacts.

The *MetrixND* Project files are linked to the *AnnualIndices*, *ShareUEC*, and *MonthlyMults* tabs in the spreadsheets. Sales, economic, price and weather information for the Census Division is provided in the linkless data table *UtilityData*. In this way, utility specific data and the equipment indices are brought into the project file. The *MetrixND* project files contain the objects described below.

Parameter Tables

- **Elas.** This parameter table includes the values of the elasticities used to calculate the *Usage* variables for each end-use. There are five types of elasticities included on this table.

  - Economic variable elasticities
  - Short-term own price elasticities
  - Short-term cross price elasticities
  - Long-term own price elasticities

- Long-term cross price elasticities

The short-term price elasticities drive the end-use usage equations. The long-term price elasticities drive the Heat, Cool and other appliance indices. The combined price impact is an aggregation of the short and long-term price elasticities. As such, the long-term price elasticities are input as incremental price impact. That is, the long-term price elasticity is the difference between the overall price impact and the short-term price elasticity.

Data Tables

- **AnnualEquipmentIndices** links to the *AnnualIndices* tab for heating and cooling indices, and *ShareUEC* tab for water heating, lighting, and appliances in the SAE spreadsheet.
- **UtilityData** is a linkless data table that contains sales, price, economic and weather data specific to a given Census Division.
- **MonthlyMults** links to the corresponding tab in the SAE spreadsheet.

Transformation Tables

- **EconTrans** computes the average usage, and household size, household income, and price indices used in the usage equations.
- **WeatherTrans** computes the HDD and CDD indices used in the usage equations.
- **ResidentialVars** computes the *Heat*, *Cool* and *Other Usage* variables, as well as the *XHeat*, *XCool* and *XOther* variables that are used in the regression model.
- **BinaryVars** computes the calendar binary variables that could be required in the regression model.
- **AnnualFcst** computes the annual historical and forecast sales and annual change in sales.
- **EndUseFcst** computes the monthly sales forecasts by end uses.

Models

- **ResModel** is the Statistically Adjusted End-Use Model.

Steps to Customize the Files for Your Service Territory

The files that are distributed along with this document contain regional data. If you have more accurate data for your service territory, you are encouraged to tailor the spreadsheets with that information. This section describes the steps needed to customize the files.

Minimum Customization

- Save the *MetrixND* project file and the spreadsheet into the same folder
- Select the spreadsheet and *MetrixND* project file from the appropriate Census Division

- Open the spreadsheet and navigate to the *Calibration* tab
- In cell "B9", replace base year Census Division use-per-customer with observed use-per-customer for your service territory
- Save the spreadsheet and open the *MetrixND* project file
- Click on the *Update All Links* button on the *Menu* bar
- Review the model results

Further Customization of Starting Usage Levels

In addition to the minimum steps listed above, you can also utilize model-based calibration process described above on pages 15-16 to further fine-tune starting year usage estimates to your service territory.

Customizing the End-use Share Paths

You can also install your own share history and forecasts. To do this, navigate to the *Share* tab in the spreadsheet and paste in the values for your region. Make sure that base year shares on the *Calibration* tab reflect changes on the *Shares* tab.

Customizing the End-use Efficiency Paths

Finally, you can override the end-use efficiency paths that are contained on the *Efficiencies* tab of the spreadsheet.

Commercial Statistically Adjusted End-Use (SAE) Spreadsheets – 2018 AEO Update

The 2018 Commercial Statistically Adjusted End-Use (SAE) spreadsheets and models have been updated to reflect the Energy Information Administration's (EIA) 2018 Annual Energy Outlook (AEO). All comparisons within this document compare the 2018 forecast with the 2017 reference case *excluding the CPP impacts*. Elements that have been updated include:

- End-use energy intensity projections
- End-use efficiency projections
- Floor stock projections
- Census Division commercial SAE project files (MetrixND)
- Revised historical saturations and efficiencies

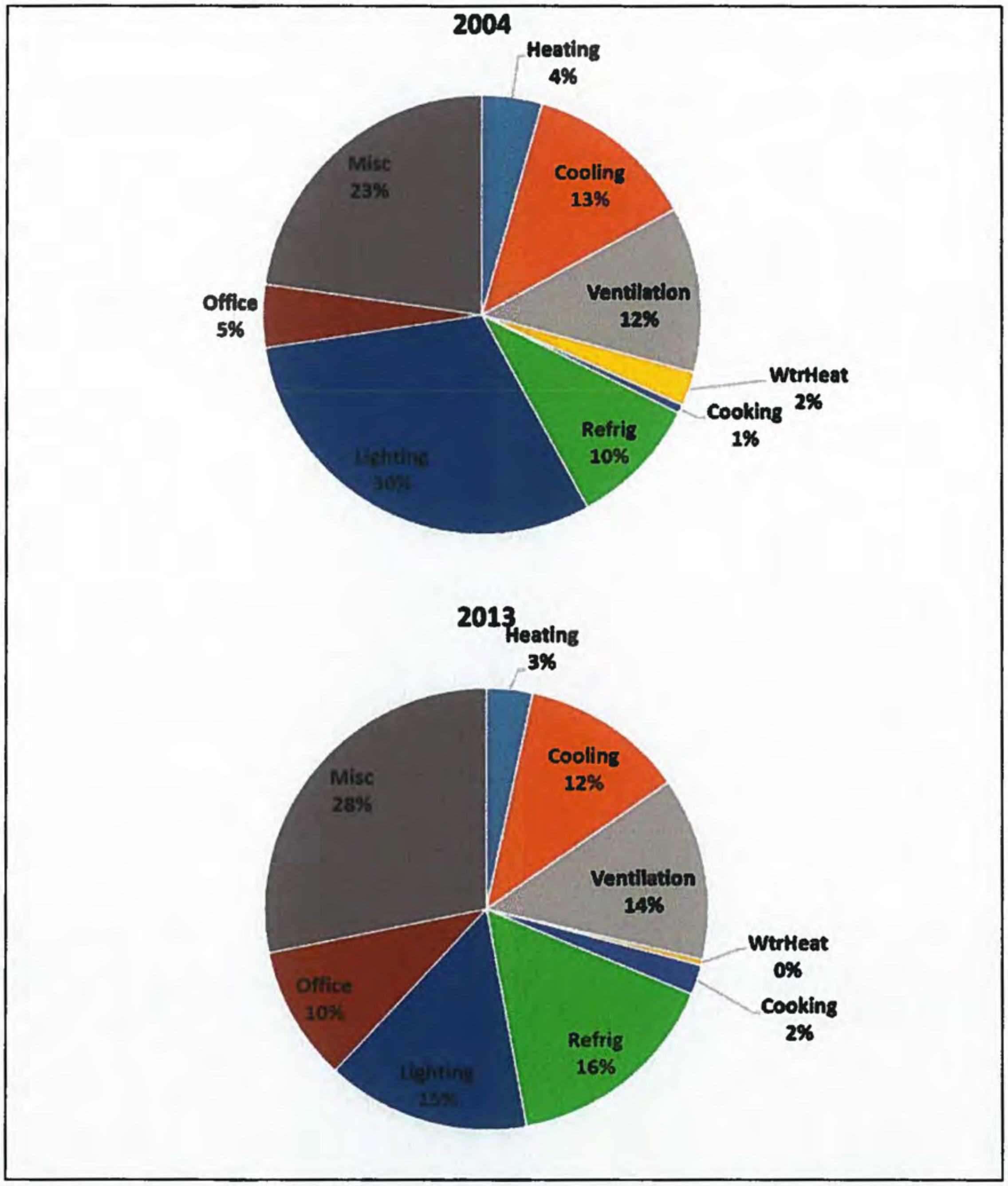
Each year, EIA develops a long-term electric and gas forecast for the commercial sector based on an end-use model, which is a component of the National Energy Modeling System (NEMS). EIA develops forecasts for 11 commercial building types, 9 electric end-uses, and 5 natural gas end-uses. The largest electric end-uses include lighting, cooling, ventilation, refrigeration, and miscellaneous use. On the gas, heating is, by far, the largest end-use, followed by water heating, and cooking.

End-use intensities are key inputs in constructing commercial SAE model variables. End-use intensities are measured on a kWh per square foot basis and natural gas end-uses are on a therms per square foot basis. Other than miscellaneous use, intensities have been declining over the last 10 years and are expected to continue to decline over the next 20 years. The decline in energy intensities are largely driven by end-use efficiency improvements. Factors driving efficiency improvements include new building and end-use standards, the availability of more efficient technology options, declining costs for high efficient technology, and federal, state, and utility programs that encourage and subsidize the adoption of more efficient technology options and building shell improvements.

1.1 2012 CBECS Update

Starting in 2017, the AEO forecast has been updated to reflect the 2012 Commercial Buildings Energy Consumption Survey (CBECS). The forecast base year has been changed from 2004 to 2013. As a result, the composition of commercial building square footage as well as end-use energy consumption has changed. The largest change has been in lighting, in 2004 lighting accounted for almost a third of total usage, by 2013 that number dropped to 15%. Lighting intensity continues to decline through the forecast period with the increased adoption of LED lighting. Figure 1 compares the distribution of end-use consumption between 2004 and 2013.

Figure 1: Base Year Electric End-Use Distribution Comparison



Where lighting has declined from 30% to 15%, the miscellaneous category has increased to represent nearly 30% of commercial use.

1.2 Electric Forecast Updates

End-use energy intensity projections are based on end-use efficiency and commercial equipment saturation. Changes in equipment stock are driven by assumptions about available technology, associated costs, energy prices, and economic conditions. Commercial electric intensities are calculated for the primary end-uses, including:

- Heating
- Cooling
- Ventilation
- Water Heating
- Cooking
- Refrigeration
- Lighting
- Office Equipment (PCs)
- Miscellaneous

Energy intensities indices provided in the SAE spreadsheets are derived from the AEO commercial forecast database. End-use intensity projections are calculated for 11 building types within 9 Census Divisions. The energy intensity (EI) is derived by dividing end-use energy consumption by square footage projections:

$$EI_{bet} = {Energy_{bet}}/{sqft_{bt}}$$

Where:

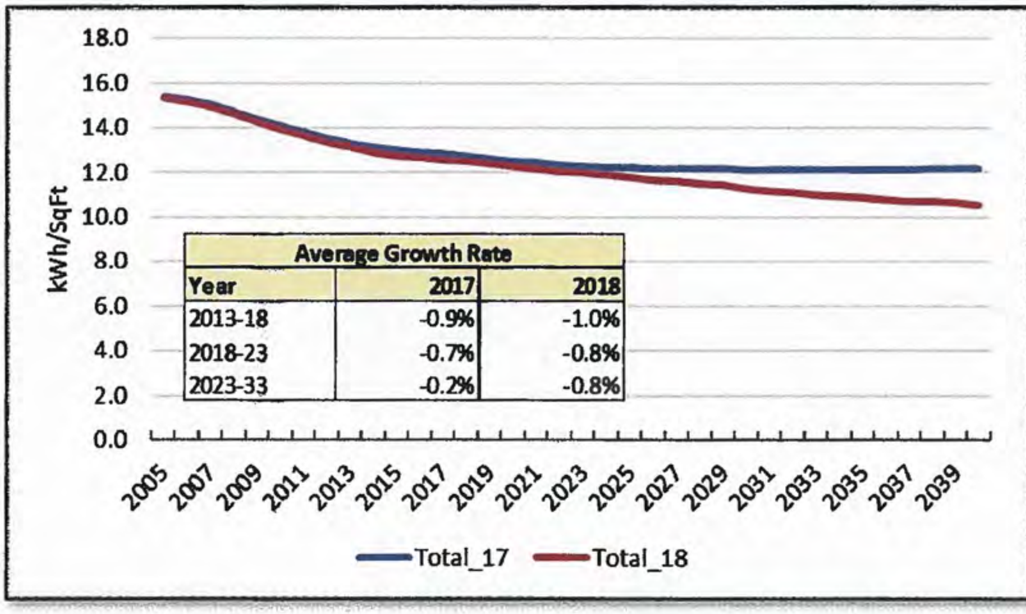
$Energy_{bet}$ = Energy consumption for end-use *e*, building type *b*, year *t*
$Sqft_{bt}$ = Square footage for building type *b* in year *t*

Total end-use energy intensities (across building types) are calculated as a weighted average of the building type intensities where the weights are based on building type square footage:

$$EI_{et} = \sum_b EI_{bet} \times \left({sqft_{bt}}/{\sum_b sqft_{bt}}\right)$$

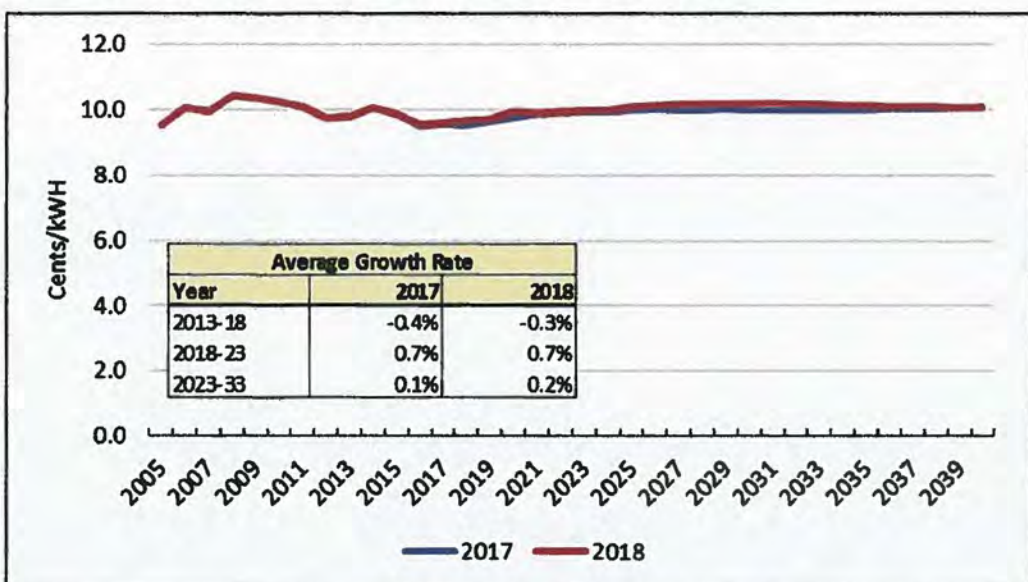
In the current forecast, EIA projects that electric intensity will decline 0.8% annually between 2018 and 2023; this is slightly faster than 0.7% decline projected in the AEO 2017 forecast. A more significant difference occurs after 2025, driven by efficiency improvement in lighting and ventilation, this is covered in greater detail in subsequent sections of this document. Figure 2 compares total commercial electric intensity projections.

Figure 2: Total Commercial Building Electricity Intensity (kWh/SqFt)



In addition to technology options and equipment costs, energy prices are also a key factor in driving equipment efficiency choices. There is very little change in price projections from the 2017 AEO. Figure 3 compares AEO 2017 and 2018 commercial price projections.

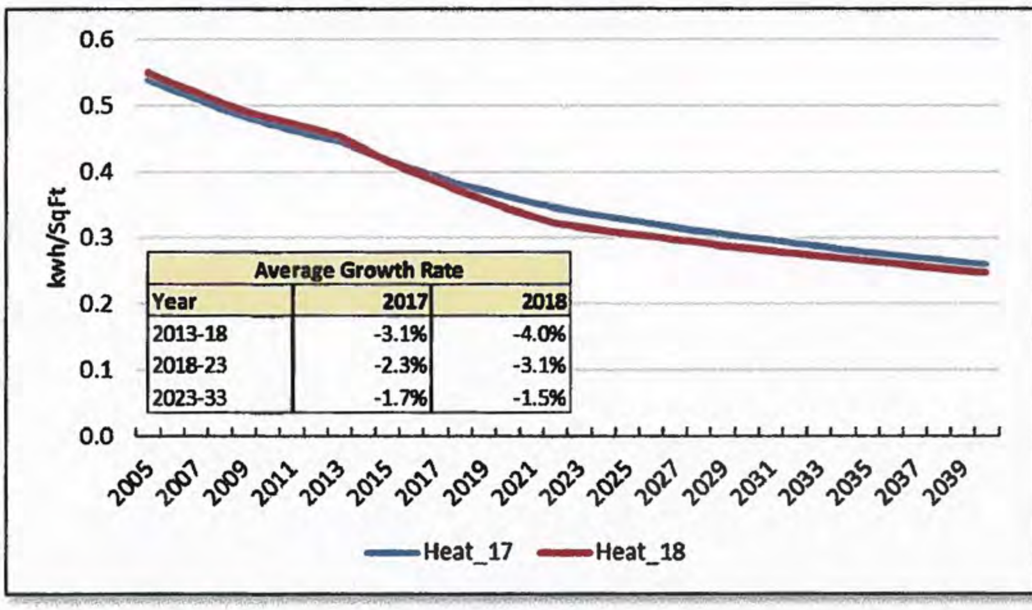
Figure 3: Commercial Electric Prices (real cents per kWh)



Electric Heating

Although electric heating is a relatively small end-use, heating intensity projections contribute to the overall decline in commercial building usage. Electric heating intensity declines on average 3.1% over the next five years and at a slower 1.5% after that. Heating intensities decline significantly faster than the 2017 forecast over the next five years. Figure 4 compares the 2018 and 2017 heating intensity forecasts.

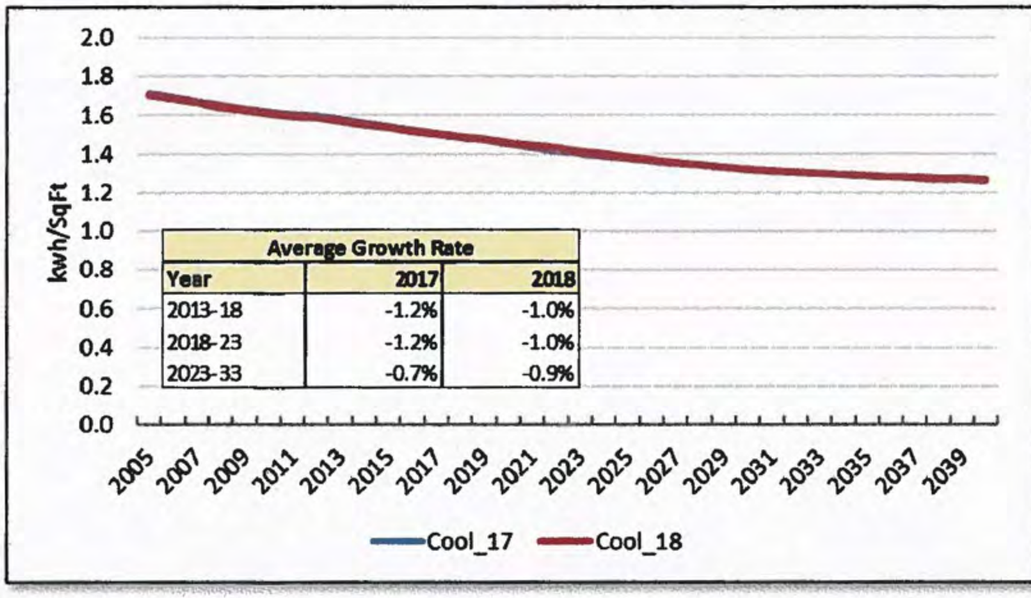
Figure 4: Electric Heating Intensity (kWh/SqFt)



Cooling

Cooling intensity is largely unchanged from 2017 with only a small difference in the near term. Figure 5 compares AEO 2017 and AEO 2018 cooling intensity projections.

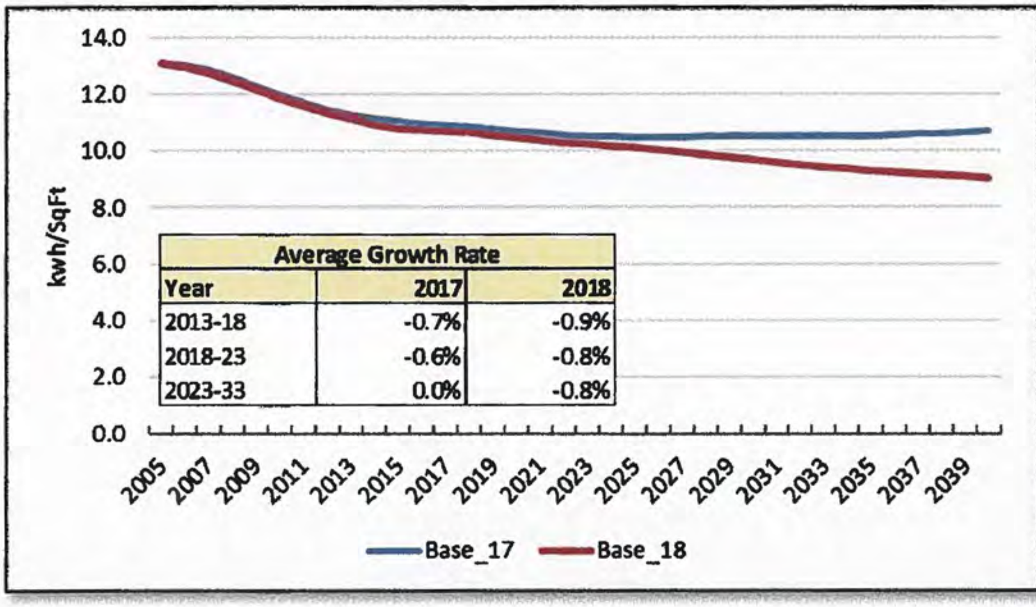
Figure 5: Cooling Intensity (kWh/SqFt)



Electric Other Use

Other large electric end-uses include ventilation, refrigeration, lighting, office equipment and miscellaneous use. The aggregation of these end-use intensities is shown in Figure 6.

Figure 6: Base Intensity (kWh/SqFt)

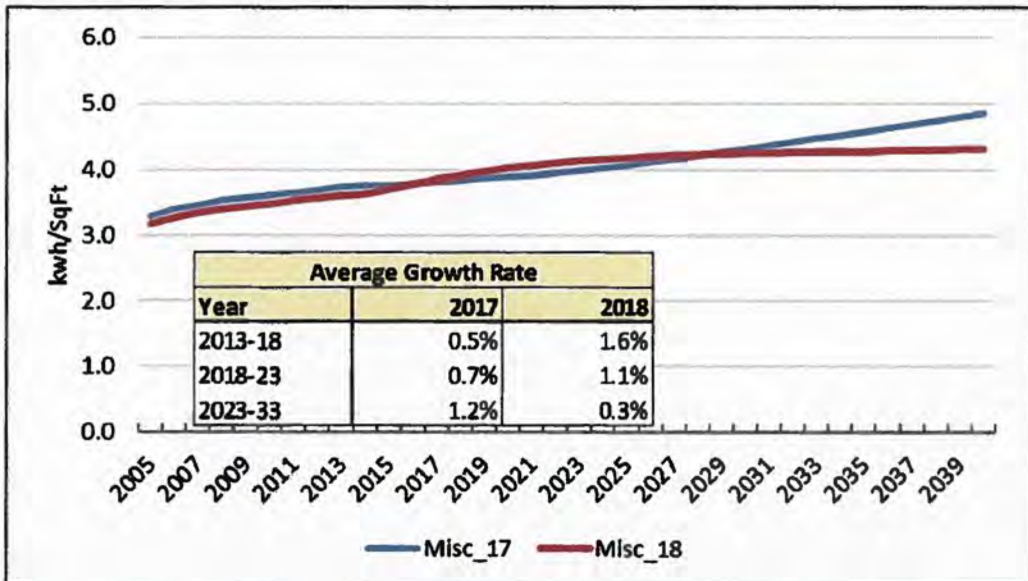


The 2018 base-use intensity declines at a significantly faster rate than the 2017 forecast. This is true for an updated historical period too. The strong base-use intensity decline is largely due to revisions to the methodology used to forecast miscellaneous consumption, and strong lighting and ventilation efficiency projections.

Miscellaneous End-Use

Approximately 30% of commercial electric use is classified as miscellaneous, which includes everything from elevator loads to medical equipment to other office plug-in loads. It is the one end-use where intensity is expected to increase. The AEO 2018 miscellaneous intensity growth is stronger in the near term but flattens after 2025. Starting with the AEO 2018 the EIA indexes miscellaneous consumption to domestic non-manufacturing gross output. In prior years, miscellaneous use was indexed to output for a few service industries. Figure 7 shows the AEO 2017 and AEO 2018 miscellaneous intensity forecasts.

Figure 7: Miscellaneous Electric Intensity (kWh/SqFt)

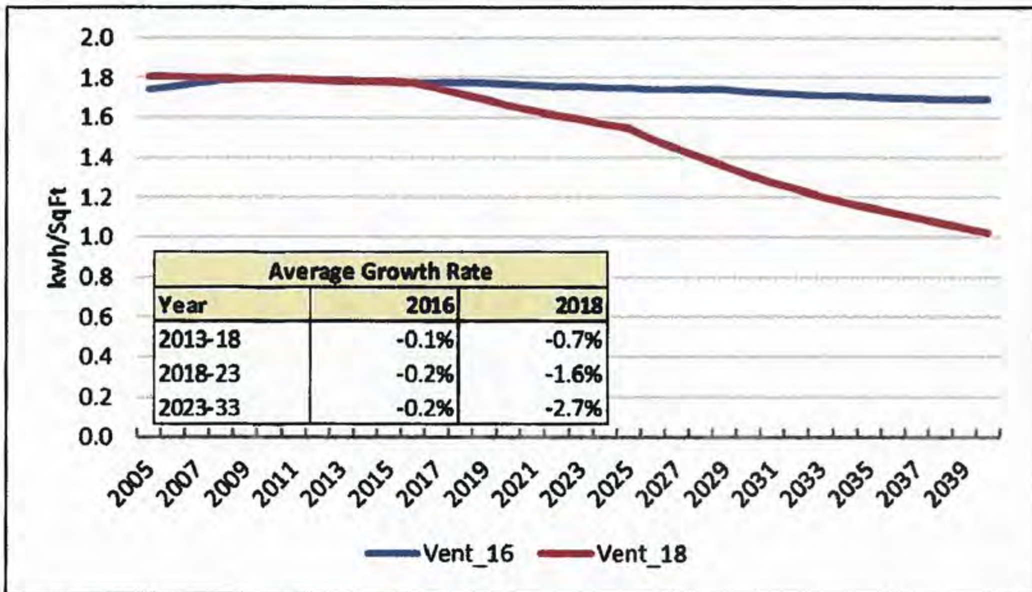


Average Growth Rate		
Year	2017	2018
2013-18	0.5%	1.6%
2018-23	0.7%	1.1%
2023-33	1.2%	0.3%

Ventilation End-Use

Ventilation accounts for rough 15% of commercial building use; it is the fourth largest commercial end-use. As commercial ventilation saturation is nearly a 100 percent, changes in ventilation intensity are largely driven by changes in system efficiency. Beginning in 2017, EIA made a significant change in projected ventilation efficiency gains. EIA now projects ventilation efficiency to improve 2.0% to 3.0% per year compared with 0.2% annual improvement in the 2016 forecast. Figure 8 compares ventilation intensity projections.

Figure 8: Ventilation Intensity (kWh/SqFt)

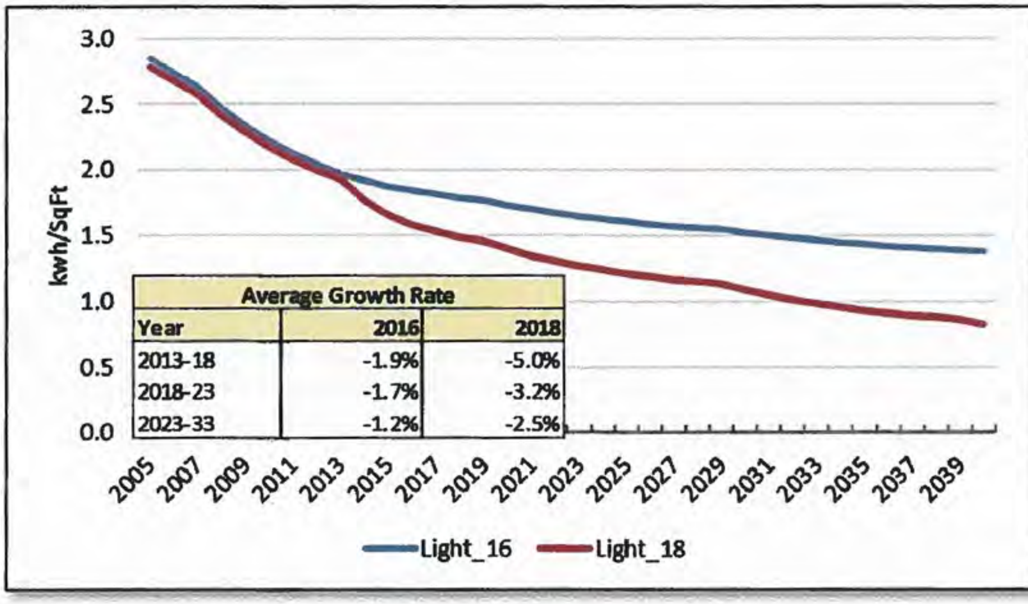


The stronger efficiency improvements assume that commercial customers will work to meet the new ASHRAE ventilation standards. Given the relative size of ventilation load, the new ventilation intensity has a significant impact on commercial sales when incorporated into the SAE forecast model. We have not been comfortable with the intensity change and to date have not incorporated the intensities into the SAE spreadsheets. This year the new ventilation intensity is included, but we are also providing the 2016 intensity. We recommend using the 2016 ventilation intensity projection until we gain a better understanding as to how the ventilation stock efficiency is calculated and can back out the embedded EE program savings.

Lighting End-Use

Commercial lighting, which in 2004 accounted for 30% of total consumption, now accounts for roughly 15% of commercial building usage. The decline in lighting as share of consumption usage has been driven by strong commercial lighting efficiency improvements. Like ventilation, starting in 2017 EIA significantly increased commercial lighting efficiency projections. Figure 9 compares the 2016 and 2018 lighting intensity projections.

Figure 9: Lighting Intensity (kWh/SqFt)



As with ventilation, 3.2% decline in average lighting intensity seems overly optimistic. It's likely that EE program savings are contributing to the strong decline. Until we can assess the impact of the embedded EE program savings, we recommend using the 2016 commercial lighting intensity projections.

Solar Adjustment

The 2018 end-use intensity forecasts also incorporate EIA's commercial own-use solar load forecast (own-use is defined as load that displaces customer use vs. sold back to the utility). For our purposes, since most utilities have their own solar load forecast, EIA's solar load forecast is added back in to SAE indices. The end-uses impacted by solar are cooling and miscellaneous. Figure 10 and Figure 11 compare the solar adjusted intensities.

Figure 10: Solar Adjustment Cooling

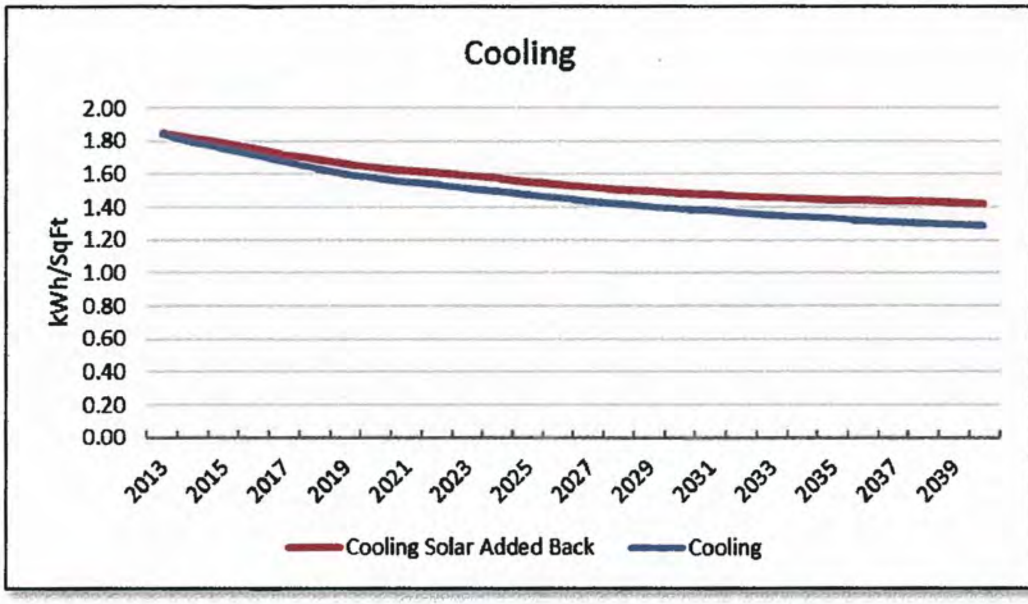
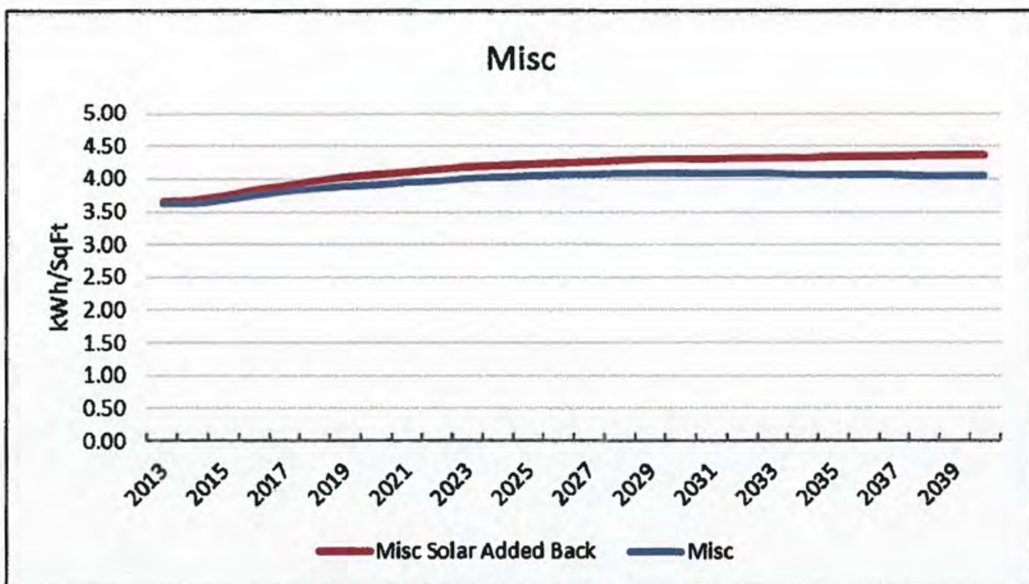


Figure 11:Solar Adjustment Miscellaneous



1.3 Gas Forecast Updates

Commercial gas intensities are calculated for the primary end-uses, including:

- Space Heating

- Space Cooling
- Water Heating
- Cooking
- Miscellaneous

Figure 12 shows the distribution of commercial gas consumption by end-use.

Figure 12: Gas End-Use Distribution

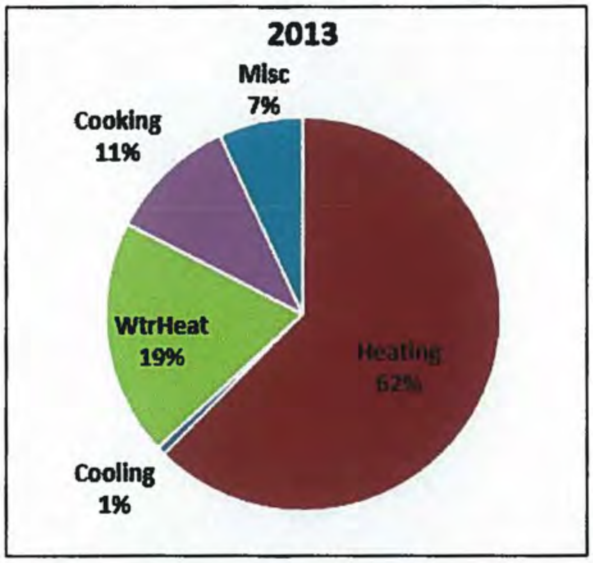
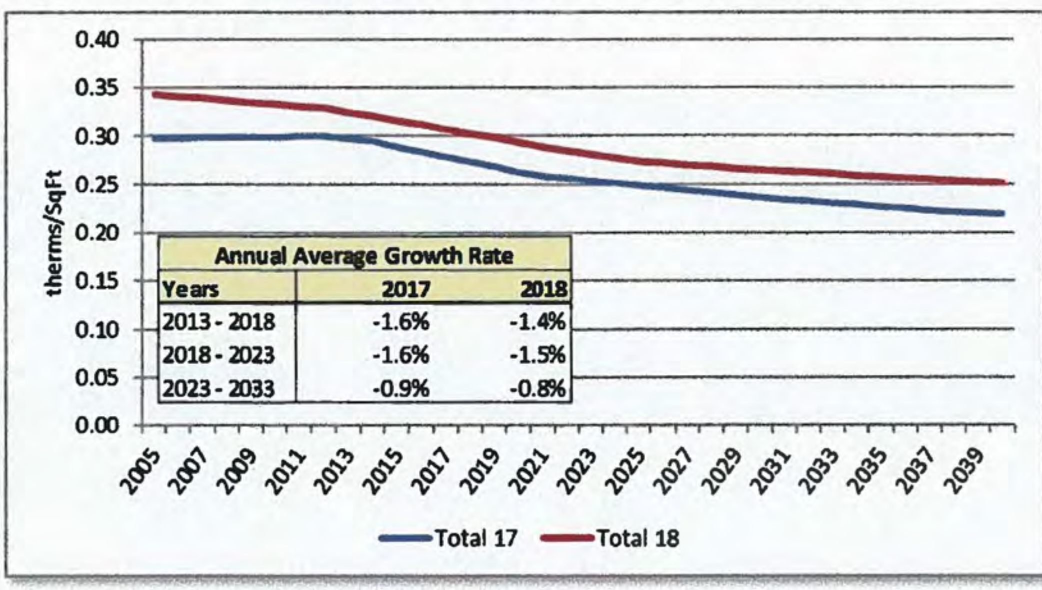


Figure 13 compares the 2017 and 2018 total commercial building gas intensity.

Figure 13: Total Commercial Gas Intensity Forecast (therm/sqft)



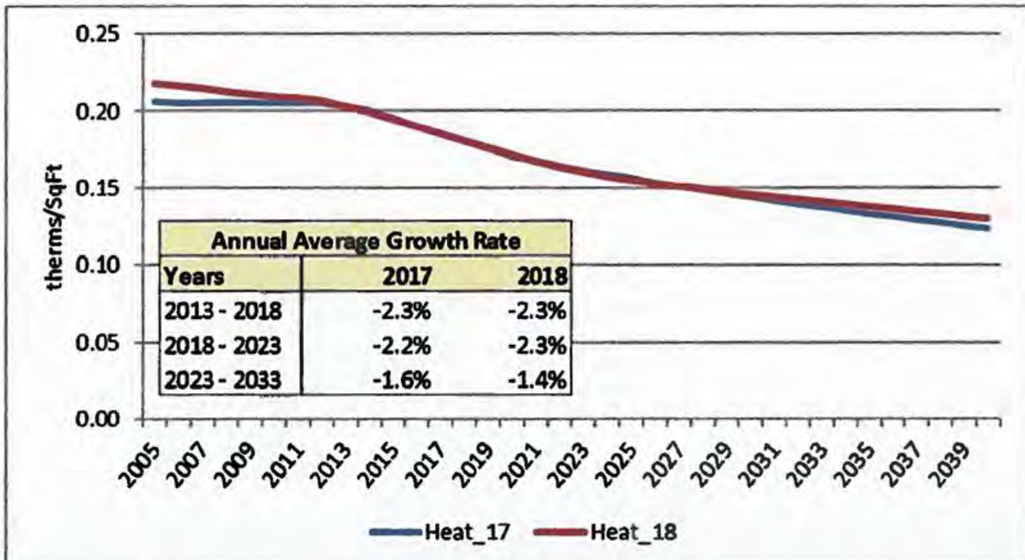
Annual Average Growth Rate		
Years	2017	2018
2013 - 2018	-1.6%	-1.4%
2018 - 2023	-1.6%	-1.5%
2023 - 2033	-0.9%	-0.8%

Gas intensity (therm per sqft) is expected decline on average 1.5% per year through 2023 and 0.8% between 2023 and 2033; this is a little weaker than in the 2017 forecast. Near-term gas intensities are relatively aggressive and likely incorporate EIA's assumption of EE program savings. The largest contributor to this decline is the heating intensity projections.

Gas Heating

Natural gas is the predominant energy source for commercial heating. Heating intensity is expected to decline at 2.3% per year through 2023. While efficiency gains do put some downward pressure on the down intensity the major driver is the implied decrease in saturations. There is very little change from the 2017 AEO. Figure 14 compares gas heating intensity projections.

Figure 14: Gas Heating Intensity (therm/sqft)

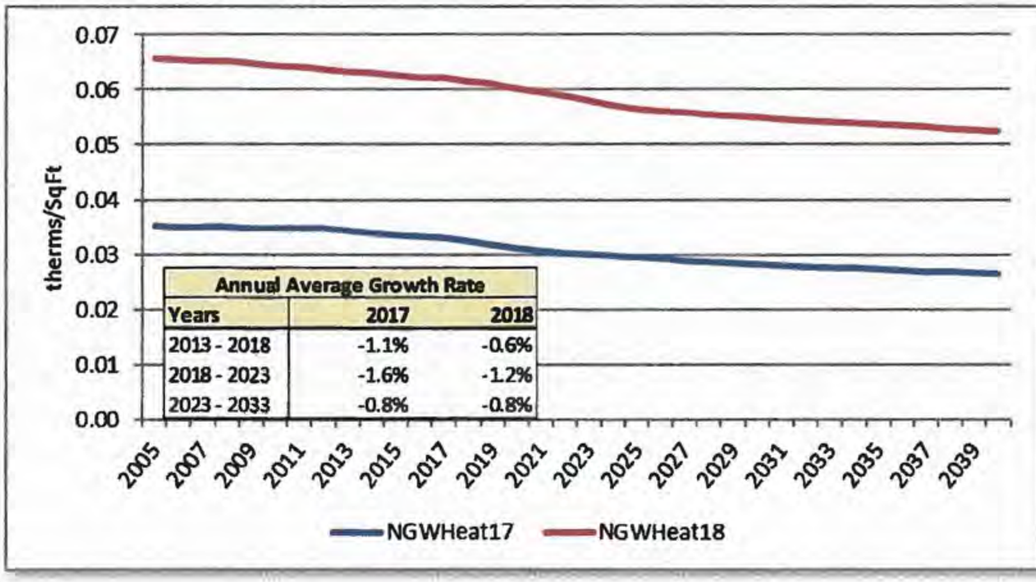


Annual Average Growth Rate		
Years	2017	2018
2013 - 2018	-2.3%	-2.3%
2018 - 2023	-2.2%	-2.3%
2023 - 2033	-1.6%	-1.4%

Gas Other End-Uses

After space heating, gas water heating is the second largest gas end-use, accounting for approximately 20% of commercial gas use. There are significant differences between the 2018 and 2017 forecast. The lower 2018 intensity estimate is due to revision in the historical consumption data in the 2013 base-year. The 2018 intensity declines at a slower rate as a result of slightly higher increase in gas water heating saturation. Figure 15 compares the 2017 and 2018 gas water heating intensity projections.

Figure 15: Gas Water Heating Intensity Projections (therm/sqft)



1.4 SAE Forecast Model Updates

MetrixND SAE models are constructed for each Census Division. The set of project files include simple floor stock models designed to mimic the EIA commercial sales forecast. In the floor stock models, monthly commercial sales are defined as a function of square footage (SqFt), end-use energy intensities (CoolEI, HeatEI and OtherEI), and monthly heating and cooling degree-day indices (HDDIndex, CDDIndex):

$$Sales_t = b_0 + b_1 \times (CoolEI_t \times SqFt_t \times CDDIndex_t) \\ + b_2 \times (HeatEI_t \times SqFt_t \times HDDIndex_t) + b_3 \times (OtherEI_t \times SqFt_t) + e_t$$

The regional models incorporate EIA's 2018 end-use intensity and square footage projections. The models can be calibrated to an individual utility service area by replacing EIA historical and forecasted square footage with utility-specific square footage estimates. A standard approach for developing a square footage forecast is to estimate a square footage model as a function of commercial employment:

$$SqFt_{t=}a_0 + a_1 \times ComEmploy_t + e_t$$

For most utilities, historical floor stock data is difficult to construct. Further, the simple floor stock model may not adequately capture the impact of short-term variations in economic activity and rate changes. The new project files also include the SAE model specifications from earlier years. In the SAE specification, estimates of long-term monthly end-use energy are imported from the SAE spreadsheet, and interacted with GDP, price, and weather conditions. An elasticity that is consistent with forecasts derived from the simple stock model is imposed on GDP. A description of the SAE model specification is outlined in Appendix A.

1.5 Excel File Updates

The 2018 commercial files, gas and electric, now contain a **Shares** worksheet, as they have in previous years. This allows users to change assumptions on relative end-use saturations, which impact calculated intensities.

The 2015 and prior SAE files contained separate Indoor and Outdoor Lighting end-uses, which have been aggregated to total Lighting starting with the 2017 files. Additionally, the non-weather sensitive end-uses, which in the past were aggregated and labeled "NonHVAC", are now labeled "Base". We felt this was a more accurate description considering ventilation is included in the aggregation. MetrixND file links will need to be edited in order for imports to work properly.

Appendix A: Commercial Statistically Adjusted End-Use Model

The traditional approach to forecasting monthly sales for a customer class is to develop an econometric model that relates monthly sales to weather, seasonal variables, and economic conditions. From a forecasting perspective, econometric models are well suited to identifying historical trends and to projecting these trends into the future. In contrast, end-use models are able to incorporate the end-use factors driving energy use. By including end-use structure in an econometric model, the statistically adjusted end-use (SAE) modeling framework exploits the strengths of both approaches.

There are several advantages to the SAE approach.

- The equipment efficiency trends and saturation changes embodied in the long-run end-use forecasts are introduced explicitly into the short-term monthly sales forecast, thereby providing a strong bridge between the two forecasts.
- By explicitly introducing trends in equipment saturations and efficiency levels, SAE models can explain changes in usage levels and weather-sensitivity over time.
- Data for short-term models are often not sufficiently robust to support estimation of a full set of price, economic, and demographic effects. By bundling these factors with equipment-oriented drivers, a rich set of elasticities can be built into the final model.

This document describes this approach, the associated supporting Commercial SAE spreadsheets, and *MetrixND* project files that are used in the implementation. The source for the commercial SAE spreadsheets is the 2018 Annual Energy Outlook (AEO) database provided by the Energy Information Administration (EIA).

1.1 Commercial Statistically Adjusted End-Use Model Framework

The commercial statistically adjusted end-use model framework begins by defining energy use ($USE_{y,m}$) in year (y) and month (m) as the sum of energy used by heating equipment ($Heat_{y,m}$), cooling equipment ($Cool_{y,m}$) and other equipment ($Other_{y,m}$). Formally,

$$USE_{y,m} = Heat_{y,m} + Cool_{y,m} + \mathrm{Other}_{y,m} \qquad (1)$$

Although monthly sales are measured for individual customers, the end-use components are not. Substituting estimates for the end-use elements gives the following econometric equation.

$$USE_m = a + b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + \varepsilon_m \quad (2)$$

Here, $XHeat_m$, $XCool_m$, and $XOther_m$ are explanatory variables constructed from end-use information, weather data, and market data. As will be shown below, the equations used to construct these X-variables are simplified end-use models, and the X-variables are the estimated usage levels for each of the major end-uses based on these models. The estimated model can then be thought of as a statistically adjusted end-use model, where the estimated slopes are the adjustment factors.

Constructing XHeat

As represented in the Commercial SAE spreadsheets, energy use by space heating systems depends on the following types of variables.

- Heating degree days,
- Heating intensity,
- Commercial output and energy price.

The heating variable is represented as the product of an annual equipment index and a monthly usage multiplier. That is,

$$XHeat_{y,m} = HeatIndex_y \times HeatUse_{y,m} \quad (3)$$

Where

- $XHeat_{y,m}$ is estimated heating energy use in year y and month m,
- $HeatIndex_y$ is the annual index of heating equipment, and
- $HeatUse_{y,m}$ is the monthly usage multiplier.

The heating equipment index is composed of electric space heating intensity. The index will change over time with changes in heating intensity. Formally, the equipment index is defined as:

$$HeatIndex_y = HeatSales_{13} \times \frac{(HeatIntensity_y)}{(HeatIntensity_{13})} \quad (4)$$

In this expression, 2013 is used as a base year for normalizing the index. The ratio on the right is equal to 1.0 in 2013. In other years, it will be greater than 1.0 if intensity levels are above their 2004 level.

$$HeatSales_{04} = \left(\frac{kWh}{Sqft}\right)_{Heating} \times \left(\frac{CommercialSales_{13}}{\sum_e kWh/Sqft_e}\right) \tag{5}$$

Here, base-year sales for space heating is the product of the average space heating intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space heating sales value is defined on the *BaseYrInput* tab. The resulting $HeatIndex_y$ value in 2013 will be equal to the estimated annual heating sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Heating system usage levels are impacted on a monthly basis by several factors, including weather, commercial level economic activity, and prices. Using the COMMEND default elasticity parameters, the estimates for space heating equipment usage levels are computed as follows:

$$HeatUse_{y,m} = \left(\frac{WgtHDD_{y,m}}{HDD_{13}}\right) \times \left(\frac{Output_y}{Output_{13}}\right) \times \left(\frac{Price_{y,m}}{Price_{13}}\right)^{-0.18} \tag{6}$$

Where

- *WgtHDD* is the weighted number of heating degree days in year *y* and month *m*. This is constructed as the weighted sum of the current month's HDD and the prior month's HDD. The weights are 75% on the current month and 25% on the prior month
- *HDD* is the annual heating degree days for 2013,
- *Output* is a real commercial output driver in year *y*,
- *Price* is the average real price of electricity in month *m* and year *y*,

By construction, the $HeatUse_{y,m}$ variable has an annual sum that is close to 1.0 in the base year (2013). The first terms, which involve heating degree days, serves to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will reflect changes in commercial output and prices, as transformed through the end-use elasticity parameters. For example, if the real price of electricity goes up 10% relative to the base year value, the price term will contribute a multiplier of about .98 (computed as 1.10 to the -0.18 power).

Constructing XCool

The explanatory variable for cooling loads is constructed in a similar manner. The amount of energy used by cooling systems depends on the following types of variables.

- Cooling degree days,
- Cooling intensity,
- Commercial output and energy price.

The cooling variable is represented as the product of an equipment-based index and monthly usage multiplier. That is,

$$XCool_{y,m} = CoolIndex_y \times CoolUse_{y,m} \tag{7}$$

Where

- $XCool_{y,m}$ is estimated cooling energy use in year y and month m,
- $CoolIndex_y$ is an index of cooling equipment, and
- $CoolUse_{y,m}$ is the monthly usage multiplier.

As with heating, the cooling equipment index depends on equipment saturation levels (*CoolShare*) normalized by operating efficiency levels (*Eff*). Formally, the cooling equipment index is defined as:

$$CoolIndex_y = CoolSales_{13} \times \frac{\left(CoolShare_y / Eff_y\right)}{\left(CoolShare_{13} / Eff_{13}\right)} \tag{8}$$

Data values in 2013 are used as a base year for normalizing the index, and the ratio on the right is equal to 1.0 in 2013. In other years, it will be greater than 1.0 if equipment saturation levels are above their 2013 level. This will be counteracted by higher efficiency levels, which will drive the index downward. Estimates of base year cooling sales are defined as follows.

$$CoolSales_{13} = \left(\frac{kWh}{Sqft}\right)_{Cooling} \times \left(\frac{CommercialSales_{13}}{\sum_e kWh / Sqft_e}\right) \tag{9}$$

Here, base-year sales for space cooling is the product of the average space cooling intensity value and the ratio of total commercial sales in the base year over the sum of the end-use intensity values. In the Commercial SAE Spreadsheets, the space cooling sales value is defined on the *BaseYrInput* tab. The resulting *CoolIndex* value in 2013 will be equal to the estimated annual cooling sales in that year. Variations from this value in other years will be proportional to saturation and efficiency variations around their base values.

Cooling system usage levels are impacted on a monthly basis by several factors, including weather, economic activity levels and prices. Using the COMMEND default parameters, the estimates of cooling equipment usage levels are computed as follows:

$$CoolUse_{y,m} = \left(\frac{WgtCDD_{y,m}}{CDD_{13}}\right) \times \left(\frac{Output_{y}}{Output_{13}}\right) \times \left(\frac{Price_{y,m}}{Price_{13}}\right)^{-0.18} \quad (10)$$

Where

- *WgtCDD* is the weighted number of cooling degree days in year *y* and month *m*. This is constructed as the weighted sum of the current month's CDD and the prior month's CDD. The weights are 75% on the current month and 25% on the prior month.
- *CDD* is the annual cooling degree days for 2013.

By construction, the *CoolUse* variable has an annual sum that is close to 1.0 in the base year (2013). The first two terms, which involve billing days and cooling degree days, serve to allocate annual values to months of the year. The remaining terms average to 1.0 in the base year. In other years, the values will change to reflect changes in commercial output and prices.

Constructing XOther

Monthly estimates of non-weather sensitive sales can be derived in a similar fashion to space heating and cooling. Based on end-use concepts, other sales are driven by:

- Equipment intensities,
- Average number of days in the billing cycle for each month, and
- Real commercial output and real prices.

The explanatory variable for other uses is defined as follows:

$$XOther_{y,m} = OtherIndex_{y,m} \times OtherUse_{y,m} \tag{11}$$

The second term on the right hand side of this expression embodies information about equipment saturation levels and efficiency levels. The equipment index for other uses is defined as follows:

$$OtherIndex_{y,m} = \sum_{Type} Weight_{13}^{Type} \times \left(\frac{Share_{y}^{Type} \big/ Eff_{y}^{Type}}{Share_{13}^{Type} \big/ Eff_{13}^{Type}} \right) \tag{12}$$

Where

- *Weight* is the weight for each equipment type,
- *Share* represents the fraction of floor stock with an equipment type, and
- *Eff* is the average operating efficiency.

This index combines information about trends in saturation levels and efficiency levels for the main equipment categories. The weights are defined as follows.

$$Weight_{13}^{Type} = \left(\frac{kWh}{Sqft} \right)_{Type} \times \left(\frac{CommercialSales_{13}}{\sum_{e} kWh \big/ Sqft_{e}} \right) \tag{13}$$

Further monthly variation is introduced by multiplying by usage factors that cut across all end-uses, constructed as follows:

$$OtherUse_{y,m} = \left(\frac{BDays_{y,m}}{30.44}\right) \times \left(\frac{Output_y}{Output_{13}}\right) \times \left(\frac{Price_{y.m}}{Price_{13}}\right)^{-0.18} \tag{14}$$

In this expression, the elasticities on output and real price are computed from the COMMEND default values.

1.2 Supporting Spreadsheets and *MetrixND* Project Files

The SAE approach described above has been implemented for each of the nine census divisions. A mapping of states to census divisions is presented in Figure 1. This section describes the contents of each file and a procedure for customizing the files for specific utility data. A total of 18 files are provided. These files are listed in Table 1.

Figure 1: Mapping of States to Census Divisions

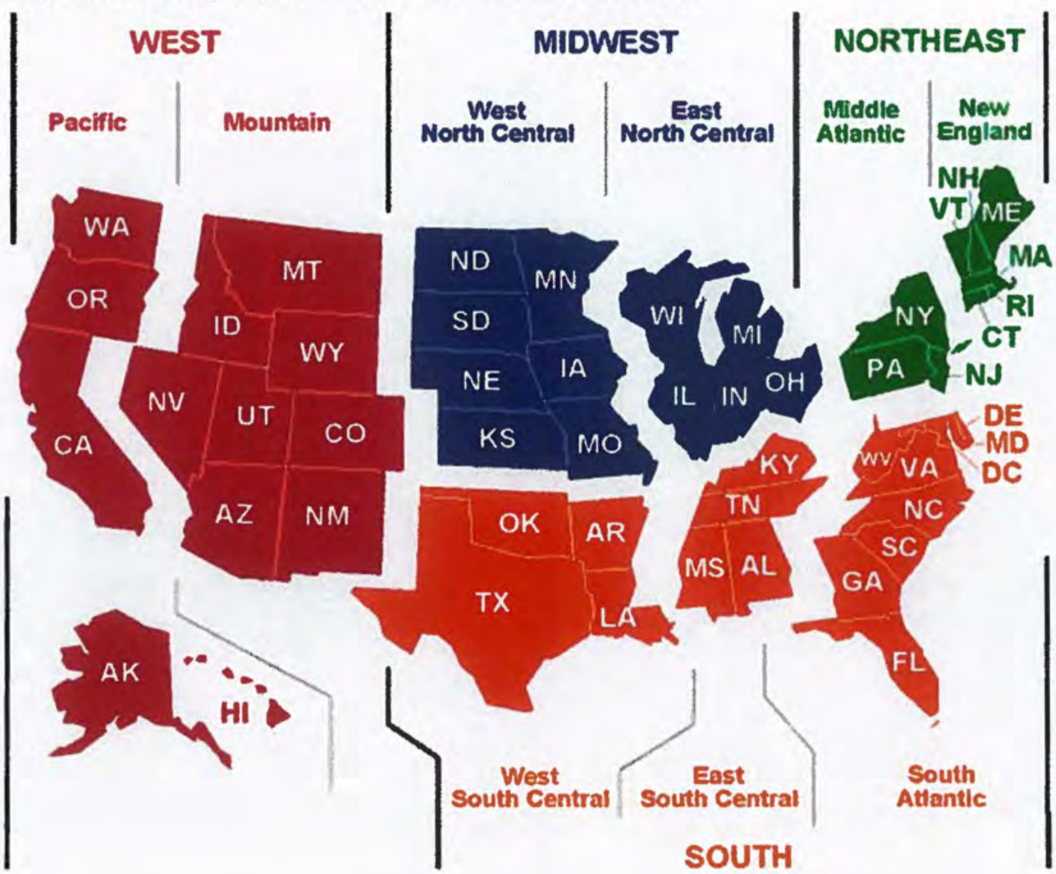


Table 1: List of SAE Files

Spreadsheets	*MetrixND* Project Files
NewEnglandCom18.xls	NewEnglandCom18.ndm
MiddleAtlanticCom18.xls	MiddleAtlanticCom18.ndm
EastNorthCentralCom18.xls	EastNorthCentralCom18.ndm
WestNorthCentralCom18.xls	WestNorthCentralCom18.ndm
SouthAtlanticCom18.xls	SouthAltanticCom18.ndm
EastSouthCentralCom18.xls	EastSouthCentralCom18.ndm
WestSouthCentralCom18.xls	WestSouthCentralCom18.ndm
MountainCom18.xls	MountainCom18.ndm
PacificCom18.xls	PacificCom18.ndm

As defaults, the SAE spreadsheets include regional data, but utility data can be entered to generate the *Heat*, *Cool*, and *Other* equipment indices used in the SAE approach. The data from these spreadsheets are linked to the *MetrixND* project files. In these project files, the end-use *Usage* variables (Equations 6, 10, and 14 above) are constructed and the SAE model is estimated.

The nine spreadsheets contain the following tabs.

- **EIAData** contains the raw forecasted data provided by the EIA
- **BaseYrInput** contains base year Census Division intensities by end-use and building type as well as default building type weights. It also contains functionality for changing the weights to reflect utility service territory.
- **Efficiency** contains historical and forecasted end-use equipment efficiency trends. The forecasted values are based on projections provided by the EIA.
- **Shares.** This tab contains historical and forecasted end-use saturations.
- **Intensity** contains the annual intensity (kWh/sqft) projections by end-use.
- **AnnualIndices** contains the annual *Heat*, *Cool* and *Other* equipment indices.
- **FloorSpace** contains the annual floor space (sqft) projections by end-use.
- **PV** incorporates the impact of photovoltaic batteries into the forecast.
- **Graphs** contains graphs of Efficiency and Intensities, which can be updating by selecting from the list in cell B2.

The *MetrixND* project files contain the following objects.

Parameter Tables

- **Parameters.** This parameter table includes the values of the annual HDD and CDD in 2013 used to calculate the *Usage* variables for each end-use.
- **Elas.** This parameter table includes the values of the elasticities used to calculate the *Usage* variables for each end-use.

Data Tables

- **AnnualIndices.** This data table is linked to the *AnnualIndices* tab in the Commercial SAE spreadsheet and contains sales-adjusted commercial SAE indices.
- **Intensity.** This data table is linked to the *Intensity* tab in the Commercial SAE spreadsheet.
- **FloorSpace.** This data table links to *FloorSpace* tab in the Commercial SAE spreadsheet.
- **UtilityData.** This linkless data table contains Census Division level data. It can be populated with utility-specific data.

Transformation Tables

- **EconTrans.** This transformation table is used to compute the output and price indices used in the usage equations.
- **WeatherTrans.** This transformation table is used to compute the HDD and CDD indices used in the usage equations.
- **CommercialVars.** This transformation table is used to compute the *Heat*, *Cool* and *Other Usage* variables, as well as the *XHeat*, *XCool* and *XOther* variables that are used in the regression model. Structural variables based on the intensity/floor space combination are also calculated here.
- **BinaryVars.** This transformation table is used to compute the calendar binary variables that could be required in the regression model.
- **AnnualFcst.** This transformation table is used to compute the annual historical and forecast sales and annual change in sales.
- **EndUseFcst.** This transformation table breaks the forecast down into its heating, cooling and other components.

Models

- **ComSAE:** The commercial SAE model (energy forecast driven by end-use indices, price, and output projections).
- **ComStruct:** Simple stock model (energy forecast driven by end-use energy intensities, and square footage).

STAFF-DR-02-023

REQUEST:

Refer to the IRP, page 63.

a. Describe the nature of Duke Kentucky's competition and the potential loss of load to these competitors. If applicable, describe the competition both in terms of customer class and technology used to generate energy delivered to these customers.

b. Explain whether the competitive threat is related to those customers expressing a desire for greener energy as noted on page 11.

c. Explain whether any of Duke Kentucky's industrial/manufacturing or large commercial customers have explored generating their own energy in a desire for greener energy. Explain whether any of those customers have taken steps toward self-generated energy.

d. From the perspective of Duke Kentucky's electric business, explain whether Duke Kentucky's natural gas business is considered a competitive threat.

e. Explain whether potentially losing economic development projects (load) to neighboring states or other service territories in Kentucky is considered competitive threat.

RESPONSE:

a. The notion of competition can include other sources of energy that a customer would substitute for Duke Kentucky service in order to meet the desired end-uses.

Larger customers in our industrial or governmental categories with substantial resources to build gas generation or smaller customers with behind-the-meter solar would both qualify under this definition.

b. The description on p. 11 of customers' several goals already mentions wishing to balance desire for sustainability progress with cost sensitivity.

c. Yes – we have had several such customers who have expressed this desire (although their stated preference was for DEK to build/own/maintain the system). One customer has built their own self-generation system, but this serves only a fraction of their need for renewable energy.

d. While gas service and electric service could be viewed as substitutes, Duke Kentucky acknowledges the complementarities between these products as well.

e. For Duke Kentucky, losing economic development projects to a neighboring state or other utilities' service areas within the Commonwealth is always considered a competitive threat. Duke Energy Kentucky prefers to win any economic development project that will add to our customer base.

PERSON RESPONSIBLE: Benjamin W. Passty – a.,b., d.;
Michael Pahutski – c., e.

Duke Energy Kentucky
Case No. 2018-00195
STAFF Second Set Data Requests
Date Received: March 27, 2019

STAFF-DR-02-024

REQUEST:

Refer to the IRP, page 63; subsection 4. Supplement all of the discussions of Planning and Forecasting models with the model equations and a more robust technical discussion to explain how each of the variables and models is constructed and function.

RESPONSE:

General Notes on the time series modeling techniques are already provided in the IRP text in page 63-64. The model equations are based on exposing MWH sales for each customer class to the data described in section 3 (which begins on page 59). An exception is the equation for predicting residential Usage-per-customer: the forecast for this equation is multiplied by the forecast for the number of residential customers to produce the final forecast for residential MWH. In order to make the estimating equations clear, tables of the major customer class model coefficients are provided in attachment bwp-NUM.

The SAE terms that appear in the Residential and Commercial equations are described in detail in the attachments provided from ITRON (please see staff-dr-02-022 Attachment 1.pdf and staff-dr-02-022 Attachment 2.pdf). For these equations, parametrized elasticities are applied to the economic drivers as well as price variables according to the table below in order to calculate the SAE terms in the equations, which are named *XHeat_, XCool_, or XOther_,* depending on the end-uses represented.

	Residential	Commercial
Price	-0.08	-0.11
Econ Driver 1: Real Median HH Income	0.35	0.35
Econ Driver 2: Total Employment	--	0.33
Econ Driver 3: Average HH Size	0.29	--

PERSON RESPONSIBLE: Benjamin W. B. Passty

STAFF-DR-02-025

REQUEST:

Refer to the IRP, page 79.

a. Explain the expected life of the new landfill at East Bend Station.

b. Explain whether the potential environmental costs discussed in this section are included in the forecasts.

RESPONSE:

a. The expected life of the new landfill at East Bend based on an average annual waste generated and placed of 786,500 CY per year is approximately 37.5 years.

b. Yes. As stated on page 79 of the IRP:
"Ongoing routine future landfill cell development costs were included in the analysis in this IRP. Lastly, looking further into the future of potential wastewater quality requirements, ongoing evolution of the ELG for additional and more stringent discharge limitations (such as for bromides), may ultimately necessitate additional waste processing changes and/or equipment installations. *A placeholder for such project cost* was included in the IRP analysis for East Bend in the early-2030's timeframe."

PERSON RESPONSIBLE: Greg Cecil – a.
Scott Park – b.

Duke Energy Kentucky
Case No. 2018-00195
STAFF Second Set Data Requests
Date Received: March 27, 2019

STAFF-DR-02-026

REQUEST:

Refer to Duke Kentucky's response to the Attorney General's First Request for Information (Attorney General's First Request), Item 2. Discuss in detail the "candidate technologies" under the proposed Affordable Clean Energy (ACE) rule and how Duke Kentucky plans to comply with the ACE rule.

RESPONSE:

Under the proposed Affordable Clean Energy (ACE) rule, EPA proposes, to identify "heat rate improvements" as the "Best System of Emissions Reductions" or BSER. In addition to improved O&M Practices, EPA also proposed a list of "candidate technologies" that would be evaluated at each generating unit to determine if it is appropriate to implement. States are expected to evaluate each of the candidate technologies when establishing a standard of performance for any particular source. The States in applying a standard of performance may take into consideration, among other factors, the remaining useful life of the existing source to which the standard would apply. EPA's proposed candidate technologies include the following:

1. Neural Network/Intelligent Sootblowers – Neural Networks are computer software systems that tie into the plant's distributed control systems. They analyze the performance of power plants at different operating loads and conditions. They operate in a predictive mode and advise the operator on adjustments to controls settings that could improve efficiency such as during rapid load changes. They also

strategically operate soot blowers which clean heat transfer surfaces thus optimizing the steam or compressed air required.

2. Boiler Feed Pump Improvements – Boiler feed pumps consume a large fraction of the auxiliary power used within a power plant. These pumps can wear over time and lose efficiency. Routine maintenance overhauls and/or upgrades can improve their efficiency.
3. Air Heater & Duct Leakage Control – Regenerative air heaters improve power plant efficiency by recovering heat from the flue gas for use in pre-heating the incoming combustion air. Inherently air heaters have some degree of air leakage into the flue gas which reduces efficiency. Maintenance and/or improvement to sealing systems can reduce this leakage and thereby improve performance.
4. Variable Frequency Drives (VFD) on Induced Draft (ID) Fans – ID fans remove the flue gases from the boiler. Because of their large size, they consume a large amount of power to operate. Utilizing VFDs would improve efficiency by reducing the speed of the ID fan at lower loads.
5. Blade Path Upgrades (Steam Turbine) – Steam turbines convert the thermal energy in steam into mechanical energy used to drive the electric generator. Steam turbines are routinely overhauled to maintain their efficiency. During overhauls, certain turbines can realize improvements in efficiency by improving the design of the turbine blades and/or the flow of steam through the machine.
6. Redesign/Replace Economizer – Economizers are the last stage of boiler tubing and are designed to recover waste heat from the flue gas before it passes into the air heater. As with most other heat transfer surface, the performance of economizer may decrease with time.

EPA has stated that not all of these proposed technologies may apply to all power plants, or they may be limited in scope. This is the case with East Bend since Duke Energy Kentucky's maintenance of East Bend has included various actions in each of these subject areas. After EPA finalized the ACE rule, Kentucky will then need to develop its "State Implementation Plan." Only at that time will Duke Energy Kentucky be able to work with the state to determine the cost effectiveness of each measure and evaluate it potentials applicability.

PERSON RESPONSIBLE: J. Michael Geers

Duke Energy Kentucky
Case No. 2018-00195
STAFF Second Set Data Requests
Date Received: March 27, 2019

STAFF-DR-02-027

REQUEST:

Refer to Duke Kentucky's response to the Attorney General's First Request, Item 11. Further, define and explain the federal restrictions related to affiliate transactions and how they would impact partnering with other Duke Energy Corporation affiliates in procuring supply-side and storage resources.

RESPONSE:

The Federal Energy Regulatory Commission's ("FERC") affiliate restriction rules are codified at 18 C.FR. §§ 35.39 and 35.44. The rules restrict transactions between a franchised public utility with captive customers and a market-regulated power sales affiliate. For example, under FERC's rules, wholesale sales of power between a franchised public utility with captive customers and any of its market-regulated power sales affiliates must be pre-approved by FERC. The terms of Duke Energy Kentucky's and Duke Energy Ohio's FERC-jurisdictional market-based rate tariffs would apply to market-based wholesale sales to market-regulated power sales affiliates.

PERSON RESPONSIBLE: Molly Suda