FILE

285

PUCO EXHIBIT FILING

Date of Hearing: 10-14-15

Case No. 14-1693-EL-RDR, 14-1694-EL-AAM

PUCO Case Caption: In the Matter of the Application Seeking approval of Ohio Power Company's Proposal to Enter into an affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider.

In the Matter of the Application of Ohio Power Company for approval of Certain ~~Accounts~~ Accounting authority.

List of exhibits being filed: Volume X

IGS 6-7

AEP 14-15-16-17-18-19

Reporter's Signature: [signature]

Date Submitted: 10-26-15

BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

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In the Matter of the Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to R.C. 4928.143 in the Form of an Electric Security Plan. : Case No. 14-1297-EL-SSO

\- - -

PROCEEDINGS

before Mr. Gregory Price, Ms. Mandy Chiles, and Ms. Megan Addison, Attorney Examiners, at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-A, Columbus, Ohio, called at 1:00 p.m. on Tuesday, October 13, 2015.

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VOLUME XXVII

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Edward W. Hill Errata Sheet

Direct Testimony Filed December 22, 2014

Page	Line	Change	Reason
2	3-7	My name is Edward W. Hill. I am Profess of Public Affairs and City and Regional Planning at the John Glenn College of Public Affairs at The Ohio State University. I am also a member of the Faculty of the Discovery Theme in Materials Science and Manufacturing Sustainability and affiliated with the Ohio Manufacturing Institute. My business address is 310P Page Hall, 1810 College Road, Columbus, Ohio 43210.	Update position, title and business address
2	19	I was a member of the Cleveland State University faculty from 1985 until my retirement in June 2015. At the time of my retirement I was Dean of the Maxine Goodman Levin College of Urban Affairs and Professor and Distinguished Scholar of Economic Development.	Update employment to include former position titles
2	21	And "was" Adjunct Professor in Public Administration at South China University of Technology.	Change to past tense
4	10-11	Change "reports" to "report" and change "are" to "is"	Clarification

Supplemental Testimony Filed May 11, 2015

Page	Line	Change	Reason
2	3-6	My name is Edward W. Hill. I am Profess of Public Affairs and City and Regional Planning at the John Glenn College of Public Affairs at The Ohio State University. I am also a member of the Faculty of the Discovery Theme in Materials Science and Manufacturing Sustainability and affiliated with the Ohio Manufacturing Institute. My business address is 310P Page Hall, 1810 College Road, Columbus, Ohio 43210.	Update position, title and business address
13	18	Add a space between the words "Companies" and "in"	Punctuation
19	20	Add a comma before the word "which" and	Misspelling and

EXHIBIT
PENGAD 800-631-6989
OMAEG
20

		change the word "high" to "higher"	punctuation

Second Supplemental Testimony Filed August 10, 2015

Page	Line	Change	Reason
2	3-5	My name is Edward W. Hill. I am Professor of Public Affairs and City and Regional Planning at the John Glenn College of Public Affairs at The Ohio State University. I am also a member of the Faculty of the Discovery Theme in Materials Science and Manufacturing Sustainability and affiliated with the Ohio Manufacturing Institute. My business address is 310P Page Hall, 1810 College Road, Columbus, Ohio 43210.	Update position, title and business address
8	FN 15	Add "supplemental stipulation at 1,5; second supplemental stipulation at 1, 2"	Clarification
8	FN17	Add "supplemental stipulation at 1,5; second supplemental stipulation at 1, 2"	Clarification
17	1	Change "their" to "the"	Misspelling
21	11	Add the word "net" before the word "costs"	Clarification
24	3	Should reference "Ms. Mikkelson's third and fourth supplemental	Clarification
24	4	Change "Parities" to "Parties"	Misspelling
28	FN 43 – line 4	Change "ration" to "ratio"	Misspelling

FILE

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Case No. 14-1693-EL-RDR, 14-1694-EL-AAM

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Reporter's Signature: [signature]
Date Submitted: 10-26-15

BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

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In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider.	: Case No. 14-1693-EL-RDR
In the Matter of the Application of Ohio Power Company for Approval of Certain Accounting Authority.	: Case No. 14-1694-EL-AAM

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PROCEEDINGS

before Ms. Greta See and Ms. Sarah Parrot, Attorney Examiners, at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-D, Columbus, Ohio, called at 9:00 a.m. on Wednesday, October 14, 2015.

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VOLUME X

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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider	)	Case No. 14-1693-EL-RDR
In the Matter of the Application of Ohio Power Company for Approval of Certain Accounting Authority	)	Case No. 14-1694-EL-AAM

DIRECT TESTIMONY OF PAUL LEANZA

On behalf of Interstate Gas Supply, Inc.

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Please introduce yourself.

A. My name is Paul Leanza. I am employed by Interstate Gas Supply, Inc. ("IGS" or "IGS Energy") as Gas Supply Director. My business address is 6100 Emerald Parkway, Dublin, Ohio 43016.

Q. Please describe your educational background and work history.

A. I received a BSBA degree from The Ohio State University in 1989 and have worked exclusively in the energy industry since 1991. My experience includes positions on both the regulated utility side of the business and non-regulated side including wholesale, retail, and trading for both natural gas and power. I am well versed in futures, swaps, and options and currently execute or oversee all NYMEX future and swap transactions and manage the fixed price position for Interstate Gas Supply, Inc.. As the Director for the Northeast Desk at Enron Energy Services I was responsible for purchasing and selling physical supplies under short and long term contractual arrangements including fixed and floating pricing for fixed and variable volumes. The position also included the management of storage contracts and supply peaking arrangements. My experience also includes power and gas trading at AEP Energy Services where I traded power in the NYISO region and traded natural gas in the Northeast region.

Q. What is the purpose of your testimony?

A. In this proceeding, the Ohio Power Company ("AEP") is asking AEP ratepayers to guaranteed cost recovery, plus a rate of return, for approximately 3,100 MW of AEP Generation Resources ("AEPGR") coal fired generation.[1] As part of its application AEP submitted testimony claiming that its proposal will help protect Ohio ratepayers from increased natural gas prices, and volatility in the natural gas market, which AEP claims will likely lead to increase cost of electric generation. In my testimony I explain that AEP's projections for natural gas prices are contrary to current market prices and futures contract prices. Further, I explain, contrary to the statements made by AEP, the current production trends in the natural gas industry are likely to place a cap on gas prices in the future as explained further in my testimony. Further these trends are likely to result in less price volatility in Ohio for the foreseeable future. Thus, the Commission should not rely on AEP's predictions with respect to natural gas prices.

II. AEP'S NATURAL GAS PROJECTIONS

Q. Has AEP made natural gas projections to support its PPA Application?

A. Yes. In Figure 1 of his testimony AEP witness Bletzacker projects Henry Hub natural gas prices from 2014 through 2030. According to forecasts supplied by Mr. Bletzacker, AEP projects natural gas prices to be at $5.47 per mmBtu in 2015, and steadily rise to $8.52 per mmBTU in 2030.

Q. Why are AEP's natural gas projections important to its PPA Proposal?

[1] The Coal Plants subject to the PPA Proposal are units at the Cardinal, Conesville, Stuart and Zimmer generation facilities ("PPA Units").

A. AEP's natural gas forecasts are important because, historically, the price of natural gas is strongly correlated with electric prices. As Mr. Bletzacker notes in his testimony "natural gas prices will set Ohio's on-peak power prices for the foreseeable future. Natural gas prices are a key component in determining the supply stack, or merit order, for the dispatch of generating units." Mr. Bletzacker further notes that a "$1 per mmBTU swing in gas prices would result in a $7 to $8 per MWh swing in combined cycle natural gas generation costs." Thus, as Mr. Bletzacker notes there is a strong correlation between the price of natural gas and the electric revenue AEP ratepayers will be able to realize under the PPA agreements for AEPGR's coal fired generation.

Q. Is your company familiar with the natural gas markets in Ohio?

A. Yes. IGS has been buying and selling natural gas in Ohio for over 25 years. In the mid-1980s IGS started out as a natural gas supplier selling to large industrial customers in Ohio. IGS has since expanded its geographic footprint and now sells natural gas in multiple states throughout the Midwest and other areas of the country to residential, commercial and industrial customers. IGS also has extensive experience buying, selling, transporting, and storing natural gas on pipelines throughout the Northeast, Midwest, and Gulf regions.

Q. Do you believe Mr. Bletzacker's natural gas forecasts are accurate?

A. No. Henry Hub natural gas futures prices are publicly published by the Chicago Mercantile Exchange (CME). A futures contract allows a buyer to purchase natural gas today for delivery at some point in the future. Mr. Bletzacker's forecasts do not reflect current market prices for natural gas, nor do they reflect the NYMEX futures prices for natural gas. Further, Mr. Bletzacker's forecasts are not supported by natural gas price projections published by the U.S. Energy Information Agency ("EIA").

Q. How do Mr. Bletzacker's forecasts compare with EIA forecasts?

A. Mr. Bletzacker's forecasts are significantly higher than all but the "High Oil Price" of the forecasts in the scenarios provided by the EIA in its Annual Energy Outlook 2015, which was released on April 14, 2015. All four EIA scenarios are below Mr. Bletzecker's forecast through 2022. Mr. Bletzacker forecasts natural gas prices to reach \$8.52 cents an mmBTU by 2030. As you can see in the Figure 1 below, the EIA has four price cases for natural gas that go out to 2040. The "Reference Case" or base case which estimates natural gas prices to be \$7.967 in 2030.[2] The highest price scenario or "High Oil Price" case estimates natural gas to be \$11.048 by 2030. The "Low Oil" price scenario predicts \$7.687 by 2030 and the "High Oil and Gas Resource" case presents prices at \$5.139. Thus Bletzacker's forecasts for 2030 exceed all but the highest cost scenario of the EIA and is over one and half times the price of gas in the low cost EIA scenario.

[2] Mr. Bletzecker's forecast is presented in nominal dollars. Because the EIA's forecast is presented in 2013 dollars, in Figure 1 below, I have converted the EIA's forecast to nominal dollars by utilizing the inflation rate of 2% assumed by the EIA.

Figure 1

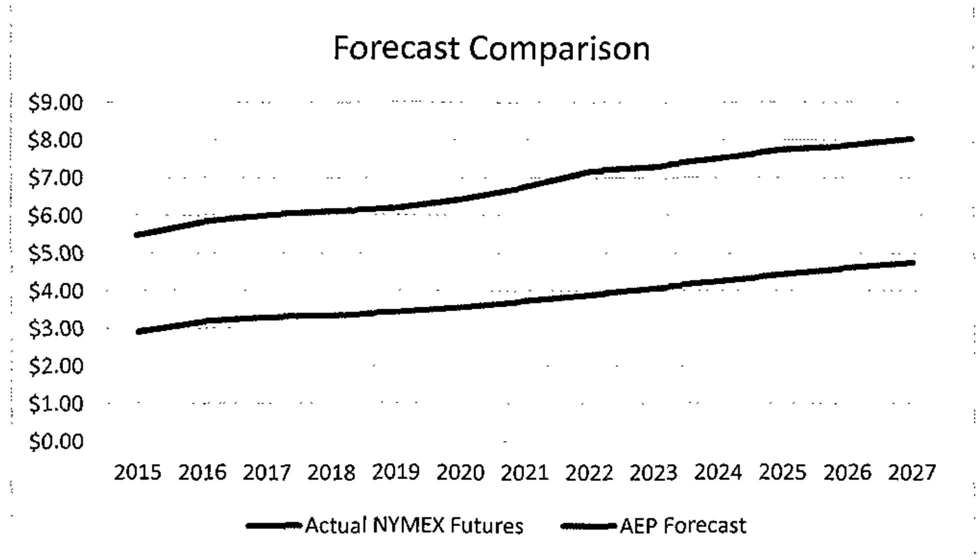
Figure ES2. Average Henry Hub spot prices for natural gas in four cases				
Year	Reference	High Oil Price	Low Oil Price	High Oil and Ga
2014	4.457	4.396	4.478	4.233
2015	3.839	3.537	3.745	3.267
2016	3.926	3.555	4.086	3.449
2017	4.113	3.929	4.427	3.713
2018	4.648	4.350	4.670	3.577
2019	5.124	4.752	4.842	3.559
2020	5.606	5.295	4.939	3.584
2021	5.882	5.917	5.085	3.796
2022	6.083	6.465	5.235	3.896
2023	6.400	7.338	5.681	4.059
2024	6.652	7.945	6.030	4.165
2025	6.925	8.497	6.354	4.325
2026	7.335	9.133	6.766	4.476
2027	7.481	9.500	7.284	4.684
2028	7.631	9.798	7.510	4.953
2029	7.839	10.419	7.482	5.024
2030	7.967	11.048	7.687	5.139

Q. How do Mr. Bletzacker's projections deviate from current natural gas market prices?

A. Mr. Bletzacker predicts a substantially higher price for natural gas than current market prices and the NYMEX futures price. Specifically, Mr. Bletzacker predicts 2015 gas prices of $5.47 per mmBtu, but a December 2015 NYMEX contract for natural gas can now be purchased for under $2.95 per mmBTU. Furthermore, if you average all the prompt month NYMEX natural gas settlements from January 1, 2015, to September 4, 2015, you end up with an average settlement of under $2.80 which is roughly half of Mr. Bletzacker's forecasted price. In 2027 (which is the farthest year out that natural gas futures prices are published), Mr. Bletzacker projects Henry Hub gas to be trading at $8.04 cents an mmBTU, yet the average monthly futures price for 2027, settled under $4.50 on September

10, 2015. Figure 2 below is a graph comparing Mr. Bletzacker's natural gas forecasts with the actual NYMEX futures prices.[3]

Figure 2



Q. Do Mr. Bletzacker's price projections correspond with the EIA long term outlook?

A. No. Reviewing Mr. Bletzacker's price projections for 2016 through 2019, it's clear that his prices are nowhere near current market conditions or EIA projections. The NYMEX natural gas settlement price averages for 2016, 2017, 2018, & 2019, as of September 10, 2015, were $2.97, $3.143, $3.205, & $3.265 respectively. The current market indicates that Mr. Bletzacker's CSAPR forecast is currently off by 100% when compared to current market prices. The

[3] The December prop month price for each year published by NYMEX was used for the Actual NYMEX Futures data. Source: http://www.cmegroup.com/trading/energy/natural-gas/natural-gas_quotes_settlements_futures.html

"Reference Case" EIA forecast indicates prices for 2016, 2017, 2018, & 2019, at $3.926, $4.113, $4.648, & $5.214 respectfully which again are well under Mr. Bletzacker's forecasts.[4]

Q. Is there any reason to believe Mr. Bletzacker's projections?

A. No. First, we know for a fact that Mr. Bletzacker's 2015 natural gas market projections are wrong. In his forecasts, Mr. Bletzacker's 2015 natural gas price is nearly double of what current spot natural gas is trading at today. Second, there are long term production trends in the natural gas markets that indicate that we will not see the high natural gas prices Mr. Bletzacker projects. Specifically with the development of horizontal drilling technology, there is now an abundance of natural gas available in the United States. In fact, since 2000, the EIA proven reserves estimates have increased from approximately 177,000 BCF to 338,000 BCF which is the highest level of proven reserves in U.S history.[5] And much of the proven, yet untapped, reserves are in the Marcellus and Utica shale which is located in Ohio and surrounding states. Thus, there is little reason to believe that Ohio will face a scarcity of natural gas driving up prices as Mr. Bletzacker predicts.

Q. Are there other reasons to doubt Mr. Bletzacker predictions?

A. Yes. Mr. Bletzacker's forecast predicts natural gas prices to rise at a rate significantly higher than the current rate of inflation. Using the current NYMEX

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[4] Source: http://www.eia.gov/forecasts/aeo/executive_summary.cfm. These numbers are adjusted for 2% inflation.

[5] Source: http://www.eia.gov/dnav/ng/hist/rngr11nus_1a.htm

price of $2.71 per mmBTU, natural gas would have to increase at an average annual rate of approximately 7.5% to reach Mr. Blezacker's $8.52 per mmBTU price in 2030. Currently the rate of inflation is only 1.64%, thus a 7.5% increase of natural gas prices year-over-year is not a reasonable expectation given the much lower rate of inflation.[6]

Q. Is there reason to believe that Mr. Bletzacker has also overstated the volatility we are likely to see in the natural gas markets?

A. Yes. In his testimony Mr. Bletzacker states "near-term natural gas prices will remain volatile as they are primarily affected by weather's deviation from normal (known as 'heating degree-day departure') which then results in deficit or surplus levels of natural gas storage in inventory. It is likely, in the event of a colder-than-normal heating season, that natural gas spot prices could exceed $8 /mmBTU." However, last winter Ohio experienced an extreme cold winter yet we did not see the significant volatility last winter that Mr. Bletzacker predicted.

Q. Can you please explain how the natural gas markets in Ohio reacted last winter?

A. Yes. The winter of 2014-2015 in Ohio was significantly colder than normal with temperatures similar to what we saw in the 2013-2014 polar vortex winter.[7]

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[6] Source: https://www.statbureau.org/en/united-states/inflation

[7] In Ohio, according to National Oceanic and Atmospheric Administration's ("NOAA") state by state heating degree day ("HDD") record, the winter of the Polar Vortex, defined as October, 2013 through April, 2014 was only three tenths of a degree per day colder, than this past winter, defined as October, 2014 through April 2015. Both winters were large deviations from normal. The Polar Vortex winter

However, the natural gas markets did not react last winter as Mr. Bletzacker predicted even in the face of extreme cold weather. Mr. Bletzacker testifies that daily cash prices are likely to exceed $8 a mmBTU during colder than normal winters. However, during January and February of 2015, which were the coldest months of the winter, the prompt month NYMEX traded around $3 per mmBTU, and throughout the winter the daily cash midpoint price for Columbia Gas, Appalachia, as published by Platts Gas Daily, never settled above $ 4.50 per mmBTU. Further, the average daily Henry Hub Spot Price , as referenced by the EIA, during the 2014-2015 winter (November through March) was $3.25 per mmBTU.[8] Mr. Bletzacker also predicted that natural gas prices would rise to $30 per mmBTU during colder than normal winters at certain local trading hubs. Again, Mr. Bletzacker predictions were incorrect, as the local hub prices did not reach nearly the $30 per mmBTU level anywhere in Ohio, even during the coldest days of the winter.

Q. *Is there a reason to believe that the trend towards lower volatility in Ohio natural gas prices is likely to continue?*

A. Yes. The amount of natural gas production throughout the United States has increased substantially even over the last five years. Further, much of that production has come from the Marcellus shale, which is located in Pennsylvania, West Virginia, New York and to a lesser extent, Ohio. In fact, as shown in Figure 3, according to a Bentek Energy report published in Platts Gas Daily, the

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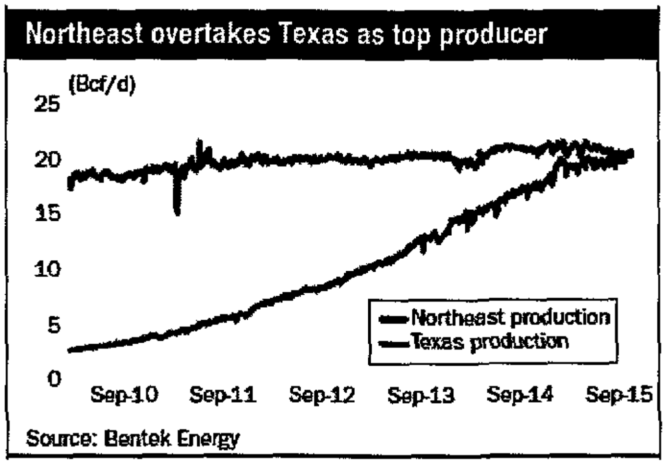
accumulated 108% of the normal HDD count and this past winter accumulated 107% of the normal HDD count Source: http://www.cpc.noaa.gov/products/analysis_monitoring/cdus/degree_days

[8] Source: http://www.eia.gov/dnav/ng/ng_pri_fut_s1_d.htm

Northeast surpassed Texas as the largest production region in the US by producing 20.37 BCF and is expected to average 21.1 BCF/day through the end of the year.

Figure 3



This increased production in and around Ohio has not only led to decreased prices, but it has also led to decreased volatility in natural gas markets given there are more opportunities to deliver gas from diverse range of sources. Thus, volatility in natural gas prices has decreased substantially even over the last few years. Moreover, given the long term trends in natural gas markets, this decreased volatility in natural gas pricing is likely to continue for the foreseeable future. Further, Bentek indicates the Northeast region, on an annual basis, has recently moved from a net importer of natural gas to a net exporter. In fact Bentek projects that the Northeast will be exporting roughly 10 BCF/day out of the Northeast region by 2020.

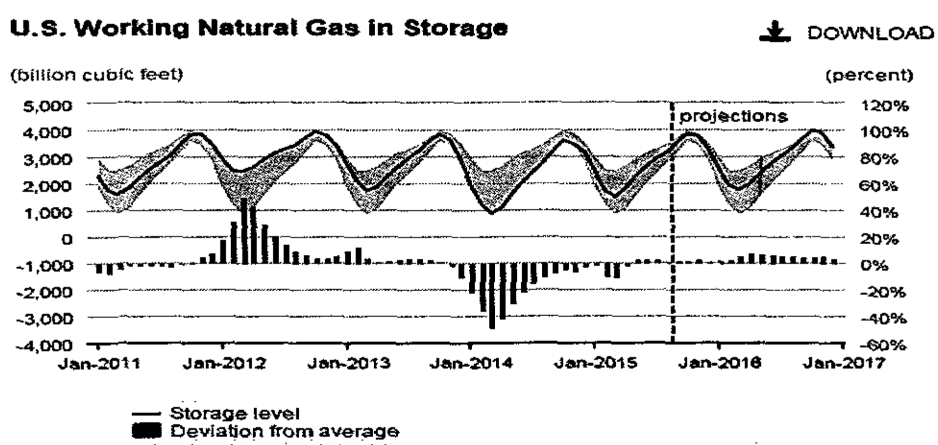
Q. Does storage inventory data also indicate lower expected volatility in the natural gas markets?

A. Yes. Natural gas storage plays an important role in price volatility. This year the natural gas industry is poised to have the largest storage balance in history at roughly 4 TCF. As you can see from the latest EIA graph below, Figure 4, not only will the balance this year be a record or extremely close but the US will struggle to not break another record next year.

Figure 4[9]

Natural Gas Inventories

On August 28, natural gas working inventories totaled 3,193 Bcf, 495 Bcf (18%) above the level at the same time in 2014 and 122 Bcf (4%) above the five-year average for that week. EIA projects end-of-October 2015 inventories will total 3,840 Bcf, which would be 43 Bcf above the five-year average.



eia Source: Short-Term Energy Outlook, September 2015

Note: Colored band around storage levels represents the range between the minimum and maximum from Jan. 2010 - Dec. 2014.

Q. Was the polar vortex prices indicative of volatility expected in the future?

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[9] http://www.eia.gov/forecasts/steo/report/natgas.cfm. The Short-term outlook also indicates that natural gas prices will be approximately $3.20 per mmbtu in 2016

A. No. First, it is important to keep the polar vortex in perspective. The polar vortex was the coldest winter that Ohio had experienced in over thirty years.[10] While there was increased volatility during that winter the average daily Henry Hub Spot Price, as referenced by the EIA for the period November 2013 through March 2014, was still only $4.68 per mmBTU for the winter.[11] Also, much has changed in the Ohio gas markets even since the polar vortex. Production in the Marcellus and Utica shale regions has increased substantially. Additional pipeline has been also been added which has increased liquidity in the markets and reduced daily and geographic volatility. Again, we saw this decreased volatility play out during the 2014-2015 winter which was nearly as cold as the 2013-2014 winter where we experienced the polar vortex.

Q. Has volatility also been reduced at Ohio specific trading hubs?

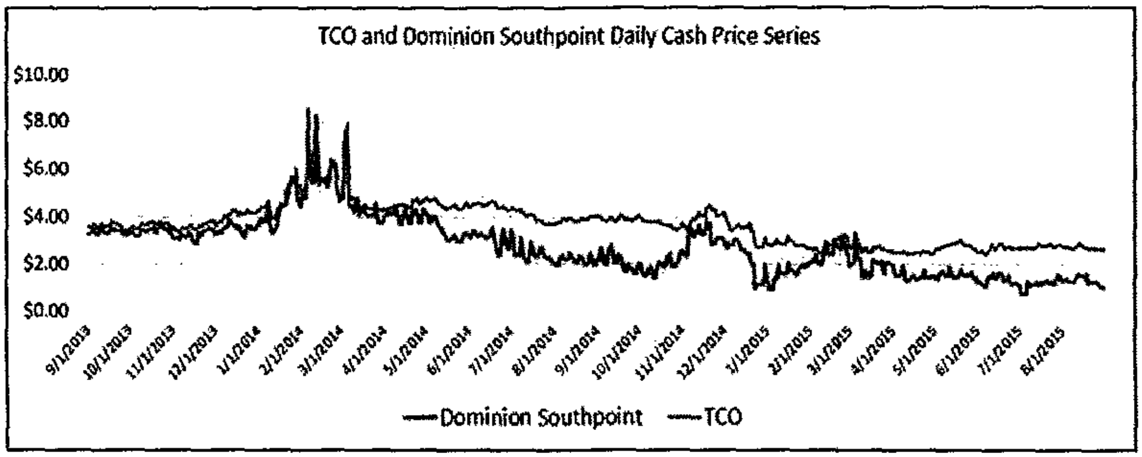
A. Yes. The Columbia Gas Pool (also known as TCO IPP) is generally considered the most liquid trading hub for supplies moving into Ohio. Columbia has over a thousand miles of pipeline in Ohio with hundreds of physical interconnects along with over 100 BCF of underground storage capacity in Ohio. Depending on specific plant location, some facilities receive supplies from Dominion Transmission which has a liquid trading point called the Dominion South Point pool. As you can see from Figure 5, which shows the daily midpoint cash prices as defined by Platts Gas Daily, both TCO & Dominion South Point did in fact see

[10] In Ohio, according to NOAA's monthly statewide temperature reporting, the winter of the Polar Vortex, defined as October, 2013 through April, 2014 was the coldest winter in the last 30 years, where the temperature for each winter is defined as the average of the monthly average temperatures reported by NOAA in each winter. This past winter in Ohio, as defined as October, 2014 through April 2015 was the third coldest winter in the last thirty years. Source: http://www.ncdc.noaa.gov/cag/

[11] Source: Source: http://www.eia.gov/dnav/ng/ng_pri_fut_s1_d.htm

elevated prices and increased volatility during the polar vortex winter. During the following winter, however, which was only marginally milder, there was dramatically reduced volatility and very little price increases especially during the extreme cold periods of January and February 2015.

Figure 5



Q. Does this conclude your testimony?

A. Yes it does.

The undersigned hereby certifies that a copy of the foregoing *Direct Testimony of Paul Leanza* was served this 11th day of September 2015 via electronic mail upon the following:

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BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider	))))))	Case No. 14-1693-EL-RDR
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DIRECT TESTIMONY OF PAUL LEANZA

On behalf of Interstate Gas Supply, Inc.

forecasts do not reflect current market prices for natural gas, nor do they reflect the NYMEX futures prices for natural gas. Further, Mr. Bletzacker's forecasts are not supported by natural gas price projections published by the U.S. Energy Information Agency ("EIA").

Q. How do Mr. Bletzacker's forecasts compare with EIA forecasts?

A. Mr. Bletzacker's forecasts are significantly higher than all but the "High Oil Price" of the forecasts in the scenarios provided by the EIA in its Annual Energy Outlook 2015, which was released on April 14, 2015. All four EIA scenarios are below Mr. Bletzecker's forecast through 2022. Mr. Bletzacker forecasts natural gas prices to reach $8.52 cents an mmBTU by 2030. As you can see in the Figure 1 below, the EIA has four price cases for natural gas that go out to 2040. The "Reference Case" or base case which estimates natural gas prices to be $7~~5~~.967~~9~~ in 2030.[2] The highest price scenario or "High Oil Price" case estimates natural gas to be $11~~7~~.048~~89~~ by 2030. The "Low Oil" price scenario predicts $7~~5~~.687~~49~~ by 2030 and the "High Oil and Gas Resource" case presents prices at $5~~3~~.139~~67~~. Thus Bletzacker's forecasts for 2030 exceed all but~~even~~ the highest cost scenario of the EIA and is over one and half times~~double~~ the price of gas in the low cost EIA scenario.

[2] Mr. Bletzecker's forecast is presented in nominal dollars. Because the EIA's forecast is presented in 2013 dollars, in Figure 1 below, I have converted the EIA's forecast to nominal dollars by utilizing the inflation rate of 2% assumed by the EIA.

Figure 1

Figure ES2. Average Henry Hub spot prices for natural gas in four cases				
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2017	4.113	3.929	4.427	3.713
2018	4.648	4.350	4.670	3.577
2019	5.124	4.752	4.842	3.559
2020	5.606	5.295	4.939	3.584
2021	5.882	5.917	5.085	3.796
2022	6.083	6.465	5.235	3.896
2023	6.400	7.338	5.681	4.059
2024	6.652	7.945	6.030	4.165
2025	6.925	8.497	6.354	4.325
2026	7.335	9.133	6.766	4.476
2027	7.481	9.500	7.284	4.684
2028	7.631	9.798	7.510	4.953
2029	7.839	10.419	7.482	5.024
2030	7.967	11.048	7.687	5.139

Q. How do Mr. Bletzacker's projections deviate from current natural gas market prices?

A. Mr. Bletzacker predicts a substantially higher price for natural gas than current market prices and the NYMEX futures price. Specifically, Mr. Bletzacker predicts 2015 gas prices of $5.47 per mmBtu, but a December 2015 NYMEX contract for natural gas can now be purchased for under $2.95 per mmBTU. Furthermore, if you average all the prompt month NYMEX natural gas settlements from January 1, 2015, to September 4, 2015, you end up with an average settlement of under $2.80 which is roughly half of Mr. Bletzacker's forecasted price. In 2027 (which is the farthest year out that natural gas futures prices are published), Mr. Bletzacker projects Henry Hub gas to be trading at $8.04 cents an mmBTU, yet the average monthly futures price for 2027, settled under $4.50 on September

"Reference Case" EIA forecast indicates prices for 2016, 2017, 2018, & 2019, at $3.926~~70~~, $4.~~3~~113~~.80~~, $4.648~~21~~, & $5.214~~4.55~~ respectfully which again are well under Mr. Bletzacker's forecasts.[4]

Q. Is there any reason to believe Mr. Bletzacker's projections?

A. No. First, we know for a fact that Mr. Bletzacker's 2015 natural gas market projections are wrong. In his forecasts, Mr. Bletzacker's 2015 natural gas price is nearly double of what current spot natural gas is trading at today. Second, there are long term production trends in the natural gas markets that indicate that we will not see the high natural gas prices Mr. Bletzacker projects. Specifically with the development of horizontal drilling technology, there is now an abundance of natural gas available in the United States. In fact, since 2000, the EIA proven reserves estimates have increased from approximately 177,000 BCF to 338,000 BCF which is the highest level of proven reserves in U.S history.[5] And much of the proven, yet untapped, reserves are in the Marcellus and Utica shale which is located in Ohio and surrounding states. Thus, there is little reason to believe that Ohio will face a scarcity of natural gas driving up prices as Mr. Bletzacker predicts.

Q. Are there other reasons to doubt Mr. Bletzacker predictions?

A. Yes. Mr. Bletzacker's forecast predicts natural gas prices to rise at a rate significantly higher than the current rate of inflation. Using the current NYMEX

[4] *Source: http://www.eia.gov/forecasts/aeo/executive_summary.cfm. These numbers are adjusted for 2% inflation.*

[5] Source: http://www.eia.gov/dnav/ng/hist/rngr11nus_1a.htm

Electric Markets, Price Trends, and Electric Choice

BEFORE THE MICHIGAN HOUSE ENERGY AND TECHNOLOGY COMMITTEE
MARCH 12, 2013

Ken Rose
Independent Consultant and
Senior Fellow with the Institute of Public Utilities
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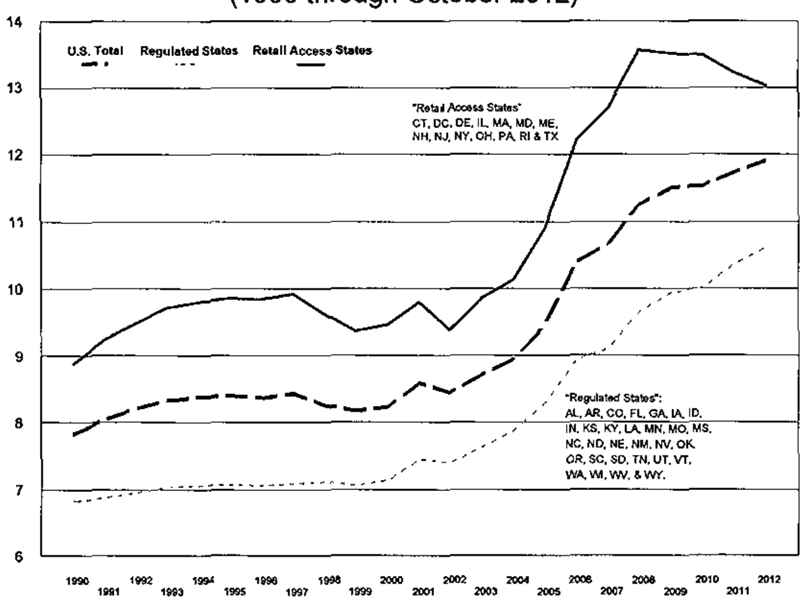
Some National Price Trends

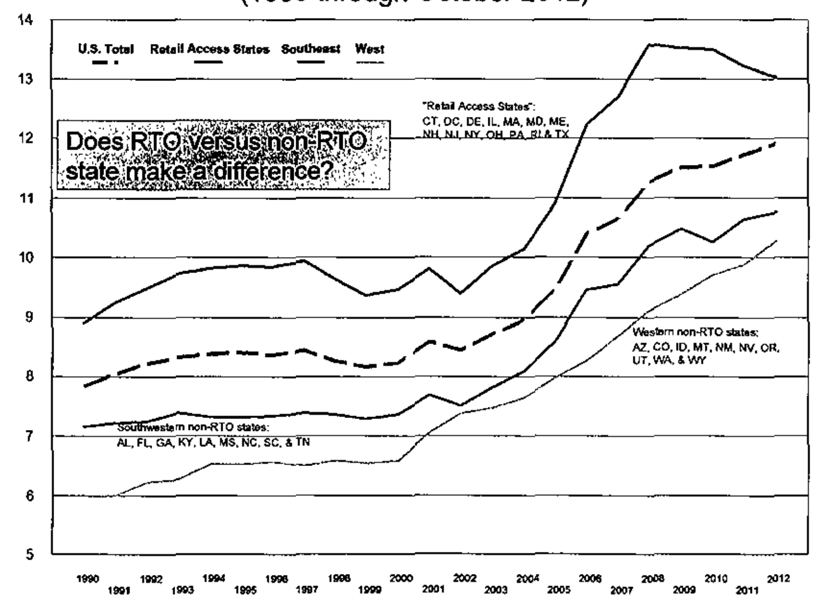
- Generally, all regions of the country are seeing higher prices since early 2000s
- Wholesale prices have fallen since 2008, and been roughly steady since
- Restructured state prices increased rapidly from 2002 until 2008, and have since leveled off (small decrease)
- For states that still regulate, prices continue to increase, but are still below states that restructured

Figure 1. Weighted annual averages for all states, regulated states and states that ended price caps for residential customers (1990 through October 2012)



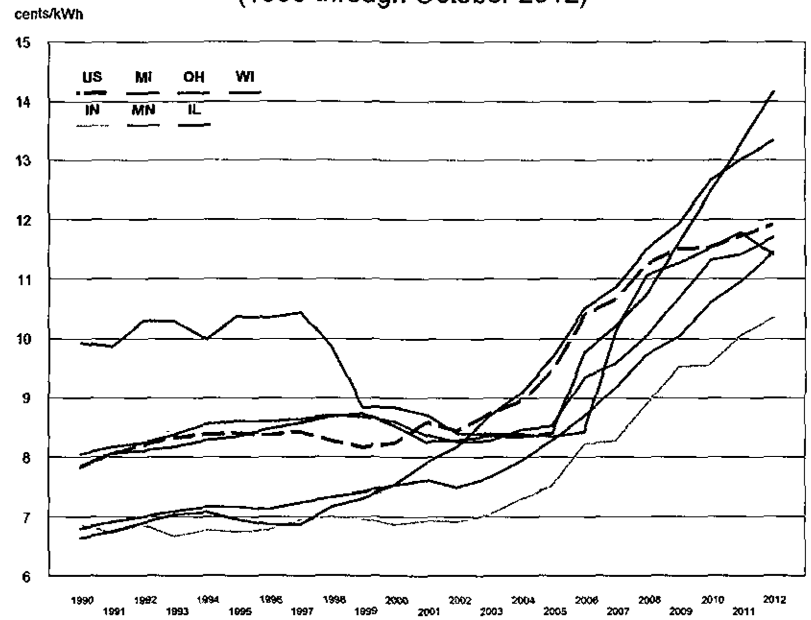
Data source: DOE/EIA.

Figure 2. Weighted annual averages for all states, non-RTO states and states that ended price caps for residential customers (1990 through October 2012)



Data source: DOE/EIA.

Figure 3. Weighted annual averages for Michigan and neighboring states
(1990 through October 2012)



Data source: DOE/EIA.

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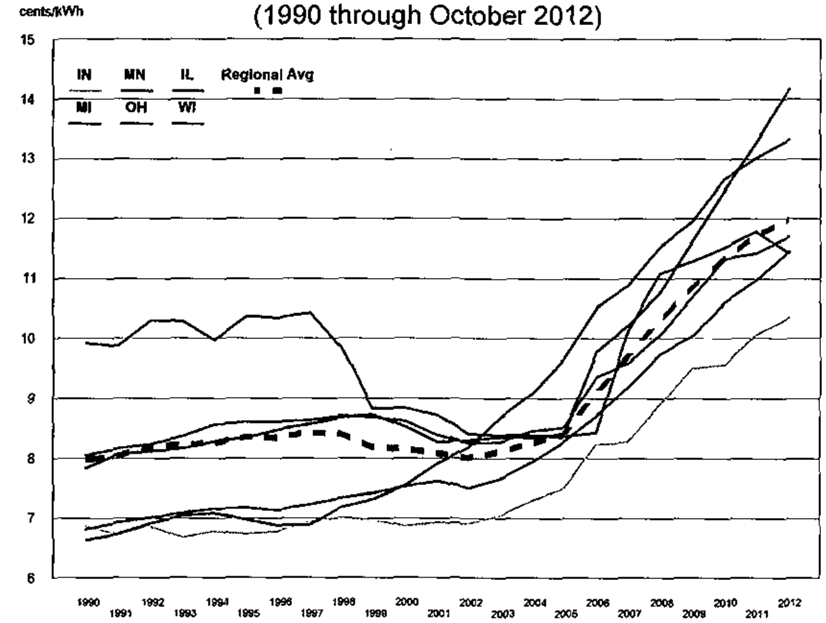
Figure 4. Weighted annual averages for Michigan, neighboring states, and *regional weighted average*.
(1990 through October 2012)



Data source: DOE/EIA.

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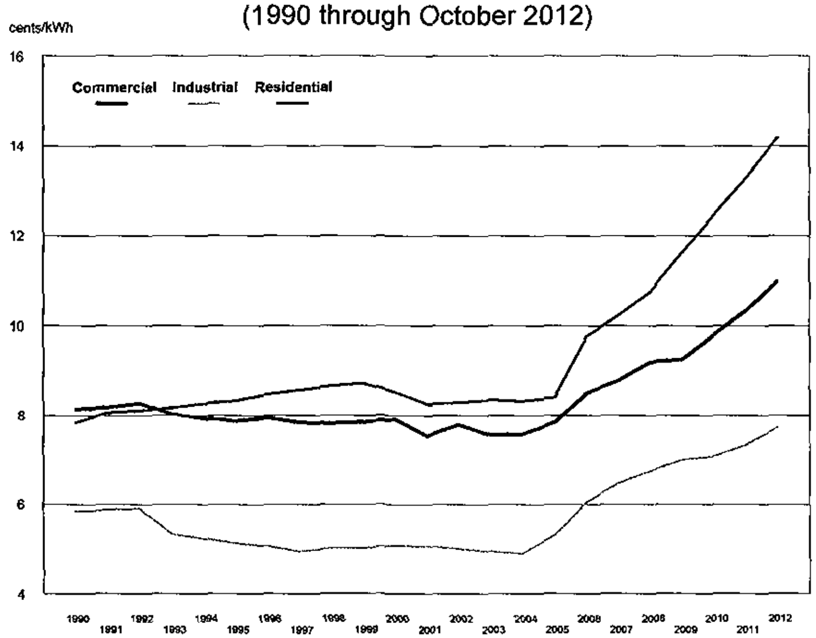
Figure 5. Michigan average prices by sector
(1990 through October 2012)



Data source: DOE/EIA.

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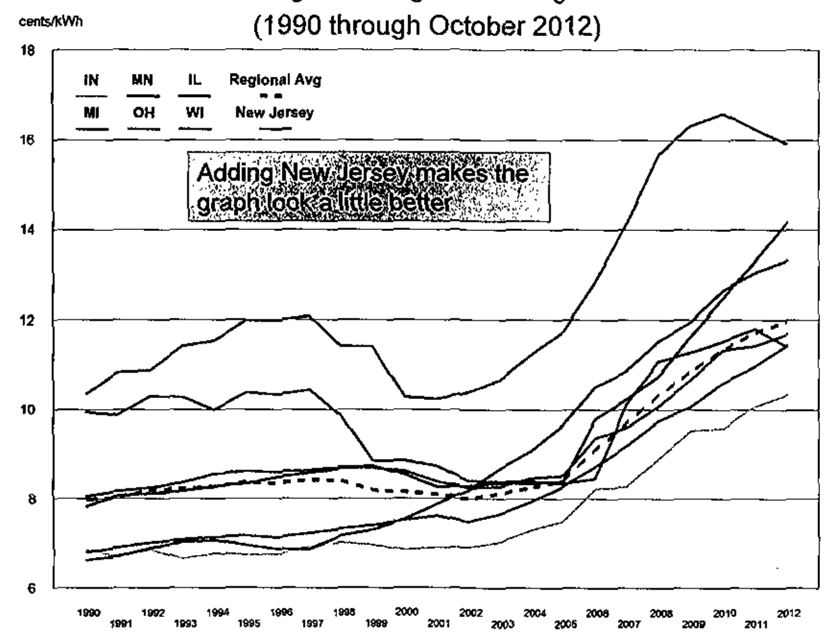
Figure 6. Weighted annual averages for Michigan, neighboring states, and regional weighted average.
(1990 through October 2012)



Data source: DOE/EIA.

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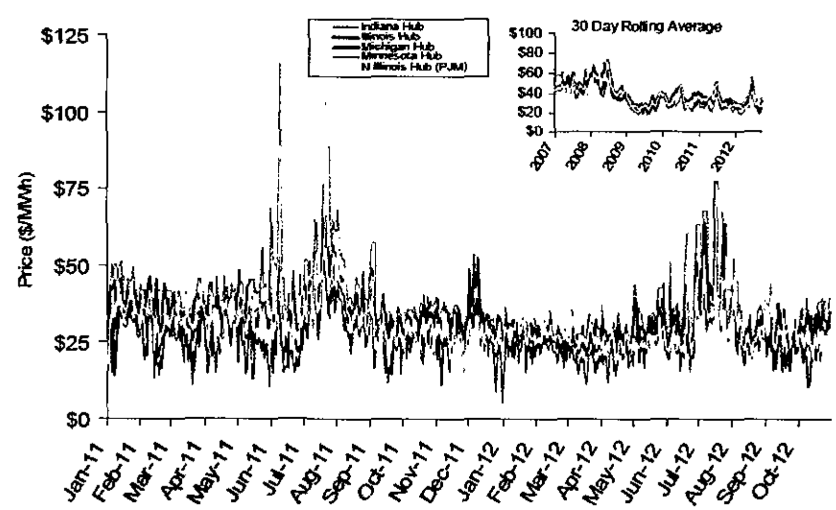
Why is Michigan and other states seeing higher prices (even though fuel prices have been falling)

- First . . .
  - Wholesale market prices?
  - Declining sales (MWh sold)?
  - EPA compliance costs?
  - Fuel costs?

Federal Energy Regulatory Commission • Market Oversight • www.ferc.gov/oversight

Daily Average of MISO Day-Ahead Prices - All Hours



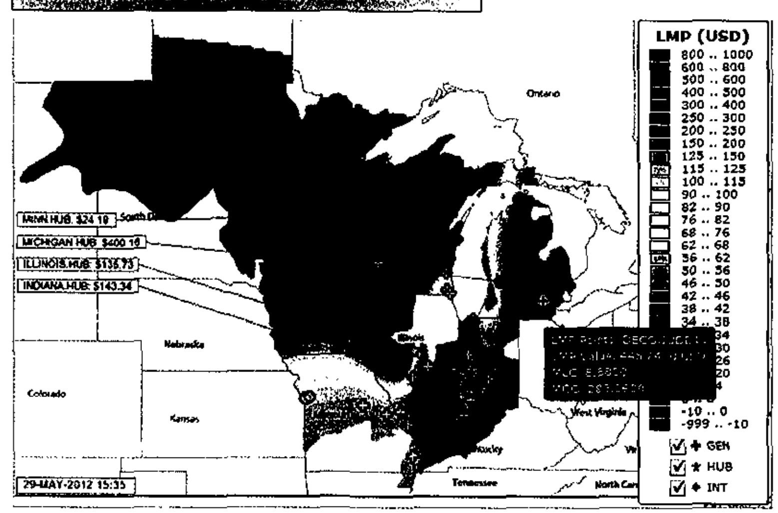
Source: FERC, November 2012, Derived from *Bloomberg data.*

Midwest Annual Average Bilateral Prices

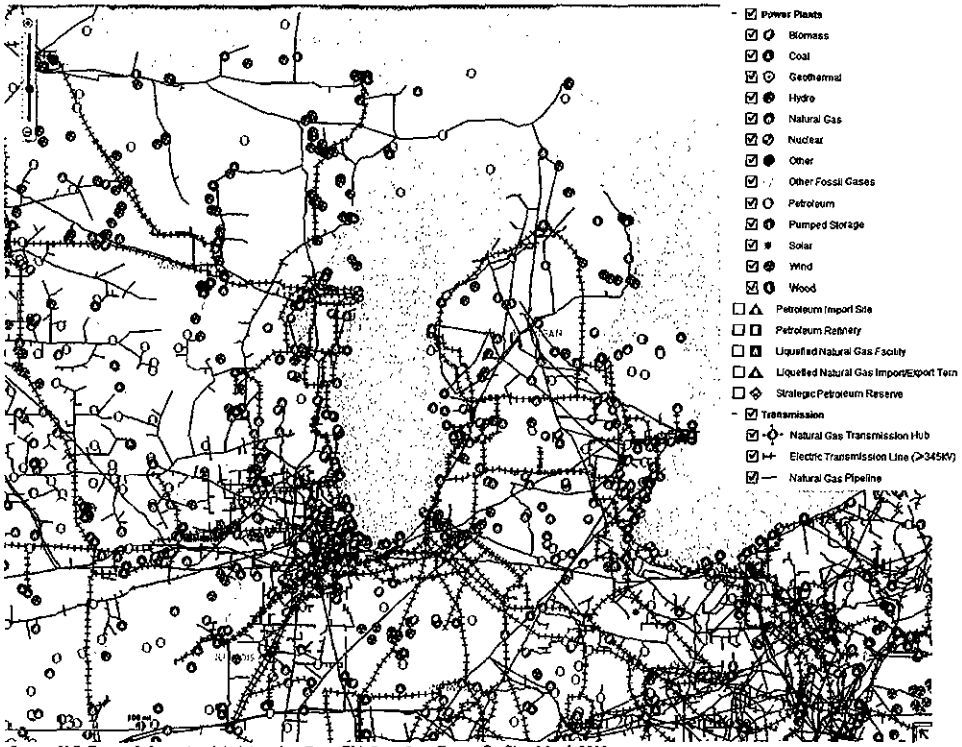
Annual Average Day Ahead On Peak Prices ($/MWh)	2007	2008	2009	2010	2011	5-Year Avg
Cinergy	$61.20	$66.88	$34.65	$41.51	$41.17	$51.20
Michigan Hub	$64.43	$69.15	$36.56	$43.68	$42.73	$53.81
Minnesota Hub	$72.32	$67.46	$32.09	$36.86	$34.57	$53.62
NI Hub	$58.93	$66.13	$34.47	$40.85	$40.31	$50.57
Illinois Hub	$59.88	$62.52	$31.36	$38.22	$38.12	$48.65
MAPP South	$61.18	$69.18	$33.31	$37.60	$35.48	$51.28

Source: FERC, November 2012, Derived from the *Platts data.*

Peak prices on May 29th 2012 . . .

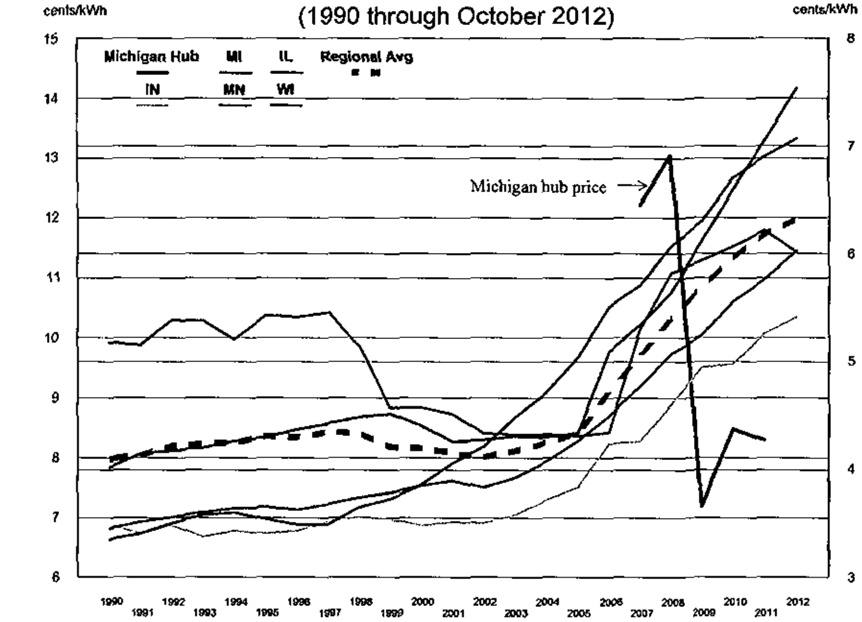


May. 29, 2012 - Interval 15:35 EST



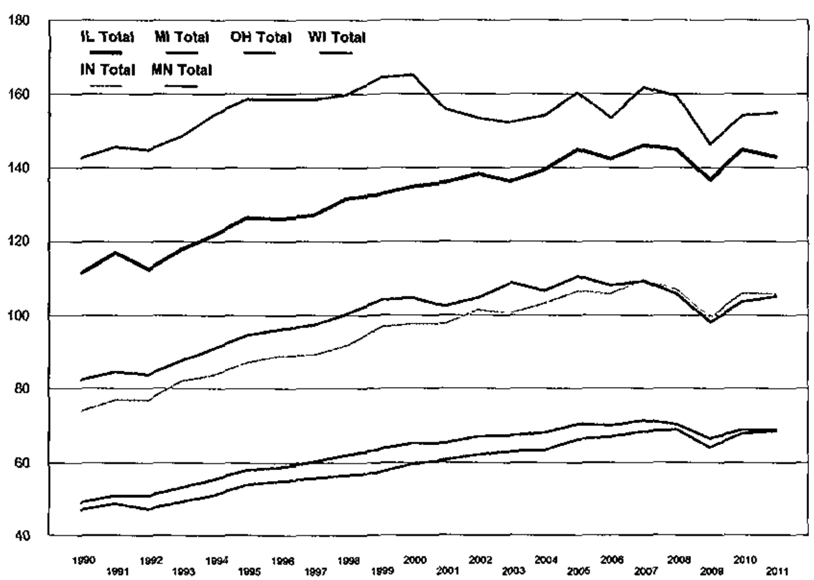
Source: U.S. Energy Information Administration, From EIA *Beta*, State Energy Profiles, March 2013.

Figure 7. Weighted annual averages for Michigan, neighboring states, regional weighted average, and MISO annual average bilateral price. (1990 through October 2012)



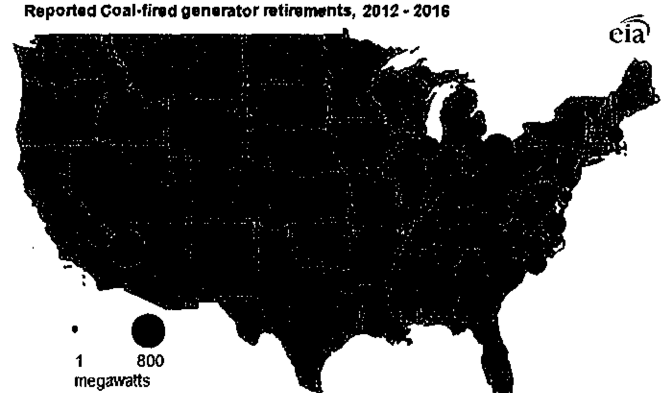
Data source: DOE/EIA.

Figure 8. All sector sales for Michigan, neighboring states, and regional weighted average. (1990 through October 2012)



Data source: DOE/EIA.

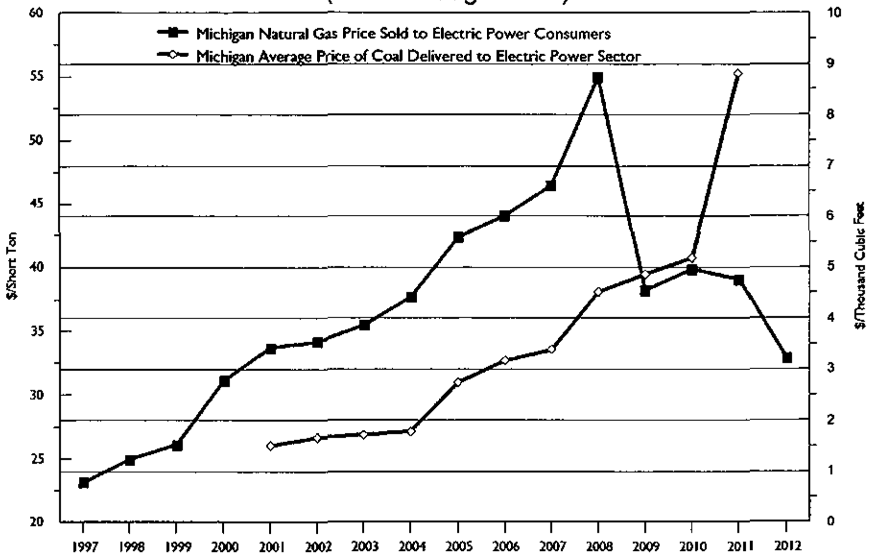
Reported Coal-fired generator retirements, 2012 - 2016

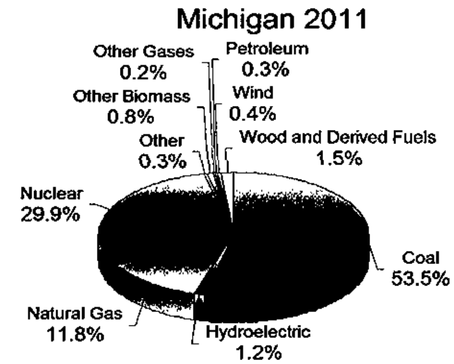


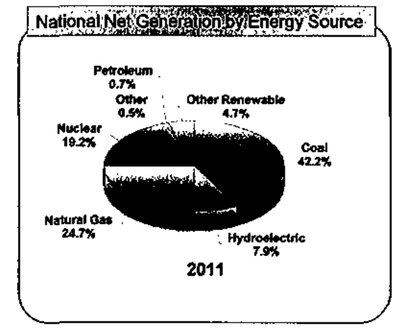
	Existing Coal Capacity[1]	Reported coal generator retirements						
		Historical			Planned			
		2009	2010	2011	2012	2013	2014	2015
Total Net Summer Capacity (MW)	317,489	529	1,528	2,517	8,890	2,098	4,715	9,865
Number Of Units	1,387	12	35	31	57	14	34	61
Average Net Summer Capacity (MW)	228	44	44	81	156	150	139	162
Average Tested Heat Rate (Btu/kWh)	11,281	12,200	12,879	10,714	10,897	13,922	11,067	10,659
Average Age at Retirement	N/A	50	54	62	56	55	57	57

[1] Reflects all coal units that existed at year-end 2011.
Source: U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."
Note: Data for 2009 through 2011 represent actual retirements. Data for 2012 through 2015 represent planned retirements, as reported to EIA. Data for 2011 through 2015 are early-release data and not fully vetted. Capacity values represent net summer capacity.

Figure 9. Michigan's electric power sector natural gas and coal prices. (1997 through 2012)

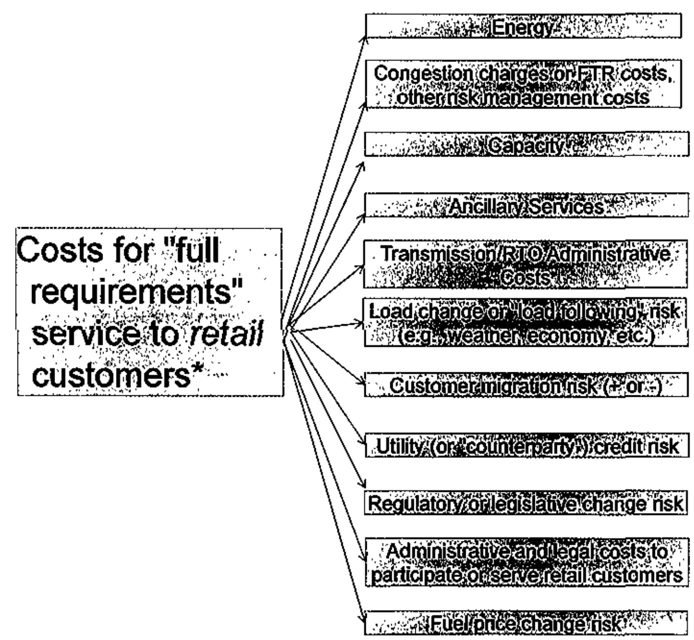






Why is Michigan and other states seeing higher prices

- These factors contribute to higher prices, but don't seem to explain all the variation
  - Wholesale market prices
  - Declining sales (MWh sold)
  - EPA compliance costs
- Even though natural gas prices have been falling, coal is going in the opposite direction
- What about new capacity costs?
  - Not by itself, EIA is showing about 365 MW in the pipeline for Michigan (probably more being considered, but not far along in planning)
- Other RTO market and non-market costs? (next slide)



✓The sum of the parts may be greater than the whole (due to new costs and risks)

✓Some of these costs did not exist with regulation

*Not all costs may apply in all cases.

McDonald's Big Mac® Unbundled

two all beef patties — Beef, salt, black pepper.

special sauce — Soybean oil, pickle relish [diced pickles, high fructose corn syrup, sugar, vinegar, corn syrup, salt, calcium chloride, xanthan gum, potassium sorbate (preservative), spice extractives, polysorbate 80], distilled vinegar, water, egg yolks, high fructose corn syrup, onion powder, mustard seed, salt, spices, *propylene glycol* alginate, sodium benzoate (preservative), mustard bran, sugar, garlic powder, vegetable protein (hydrolyzed corn, soy and wheat), *caramel color*, extractives of paprika, soy lecithin, turmeric (color), calcium disodium EDTA (protect flavor).

lettuce

cheese — Milk, water, *milkfat*, *cheese culture*, sodium citrate, salt, citric acid, sorbic acid (preservative), sodium phosphate, artificial color, lactic acid, acetic acid, enzymes, soy lecithin (added for slice separation).

pickles — Cucumbers, water, *distilled* vinegar, salt, *calcium chloride*, alum, potassium sorbate (preservative), natural flavors (plant source), polysorbate 80, extractives of *turmeric* (color).

onions

on a sesame seed bun — Enriched flour (bleached wheat flour, malted barley flour, niacin, reduced iron, thiamin *mononitrate*, *riboflavin*, *folic* acid, *enzymes*), water, high fructose corn syrup, sugar, soybean oil and/or partially hydrogenated soybean oil, contains 2% *or less* of the following: salt, calcium sulfate, calcium carbonate, wheat gluten, ammonium sulfate, ammonium chloride, dough conditioners (sodium stearoyl lactylate, datem, ascorbic acid, azodicarbonamide, mono- and diglycerides, *ethoxylated monoglycerides*, monocalcium phosphate, enzymes, guar gum, calcium peroxide, soy flour), calcium propionate and sodium propionate (preservatives), soy lecithin, sesame seed.

- One bundled Big Mac cost about $3.50*
- What would it cost unbundled?

*Prices vary by location

Benefits & Costs of an RTO Structure

Benefits

- Capital efficiencies (no over-capitalization from ROR regulation)
- Operational efficiencies (lower operating costs)
- Savings from scale economies from operating a large RTO
- Less regulatory compliance cost (warning: may be higher!)
- Can facilitate variable resource integration (however, can be accomplished by other means)

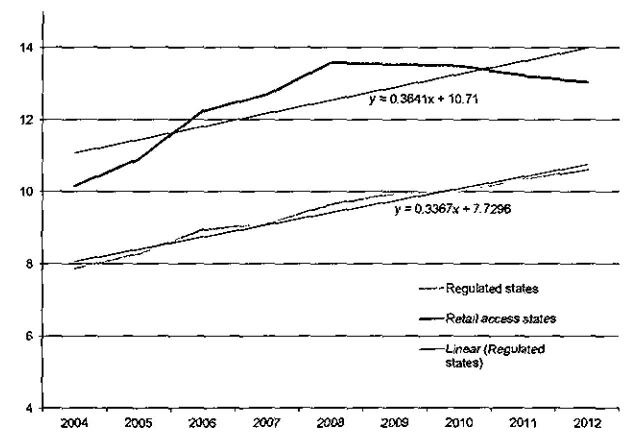
Costs

- De-integration costs, from loss of vertical economies (when one decentralized entity *supplied all* products and services, i.e., Big Mac example)
- Market power (made worse from any increase in market concentration)
  - cannot assume bidders will *bid their cost*
  - cannot assume mkt monitoring *will fix it*
- *RTO operation (or administrative)* costs
- *Business costs of market participants* incurred to deal with ISO/RTO complexity
- Possible underinvestment in infrastructure (e.g., transmission)
- Higher transmission congestion *associated with trading* over a larger *footprint*

Wrapping up . . .

- Not saying that one option is clearly worse or better than the other – *retail access v regulation*, but
  - . . . there appears to be no clear benefit for retail customers, unless you look at just the last couple years, with retail choice – and that *could* quickly change if natural gas *prices increase again* (as they have in the not too distant past)
  - cost-based regulation was no simple matter, but if the "restructured" model can't beat it, then *something's wrong*
- Not always sure what "competition" *has* to do with what we have *been doing* the past 20 years
  - replaced a complex, cumbersome, and expensive regulatory system with a complex, cumbersome, and expensive "*deregulatory*" system
  - the current RTO (wholesale) and retail access-based *model* is *a composite* of different markets, that are highly regulated and frequently adjusted by FERC and the states
- Most of the country is facing the same cost *pressures* (environmental, capacity, flat demand, *renewable* costs)

Figure 10. From another perspective . . .



- Just looking from 2004 through 2012, the average rate of change is not that different between the two groups of states
- So . . . it's fair to ask where's the savings?

Figure 11.

Even Texas (yes, Texas) follows the same trend line over the entire time period

Maybe it doesn't matter what we do . . . because of the underlying economics of the industry

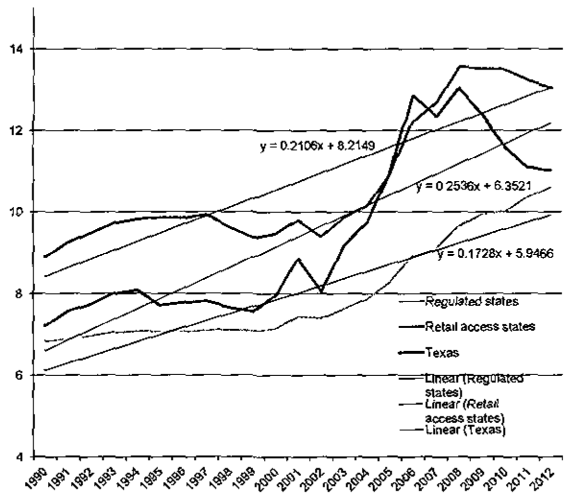
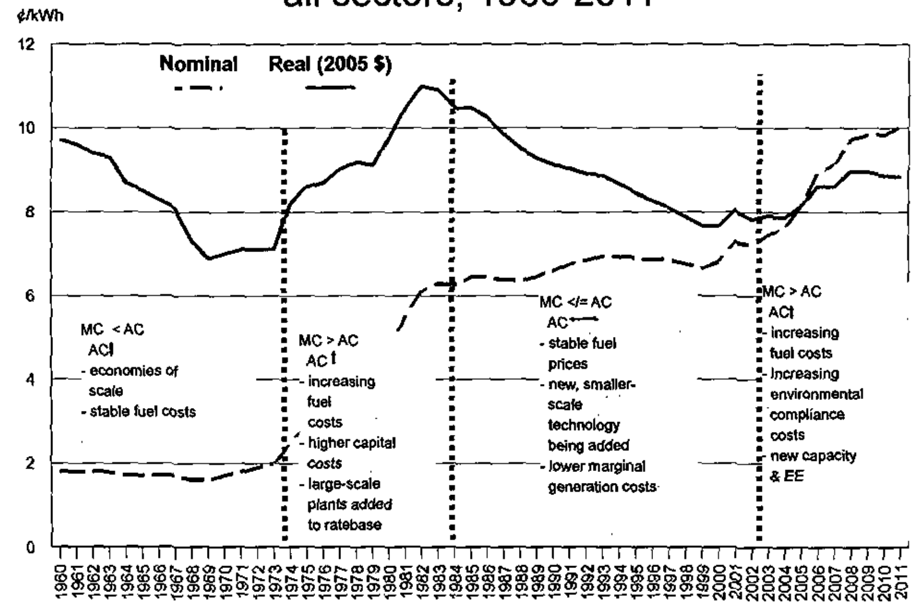


Figure 12. Average retail price of electricity, all sectors, 1960-2011



Data source: DOE/EIA.

THOMSON REUTERS STREETEVENTS

EDITED TRANSCRIPT

DYN - Dynegy Inc Corporate Investor Day

EVENT DATE/TIME: JUNE 25, 2015 / 12:00PM GMT

EXHIBIT

PENGAD 800-631-6989

AEP 15

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CORPORATE PARTICIPANTS

Bob Flexon *Dynegy Inc. - President & CEO*

Carolyn Burke *Dynegy Inc. - EVP, Business Operations & Systems*

Julius Cox *Dynegy Inc. - CAO*

Jeff Coyle *Dynegy Inc. - VP Operations Support*

Sheree Petrone *Dynegy Inc. - EVP, Retail*

Hank Jones *Dynegy Inc. - Chief Commercial Officer*

Clint Freeland *Dynegy Inc. - CFO*

Andy Smith *Dynegy Inc. - Managing Director, IR*

CONFERENCE CALL PARTICIPANTS

Julien Dumoulin-Smith *- Analyst*

Mark Fisher *AF Capital - Analyst*

Eric Flown *Goldman Sachs - Analyst*

Greg Gordon *Evercore ISI - Analyst*

Michael Lapides *Goldman Sachs - Analyst*

Stacey Nemeroff *Bloomberg Intelligence - Analyst*

Felix Carmen *Visium Asset Management - Analyst*

Jeff Cramer *Morgan Stanley - Analyst*

Mitchell Moss *Lord Abbett - Analyst*

Angie Storozynski *Macquarie - Analyst*

William Frohnhoefer *BTIG - Analyst*

Evan Kramer *Silver Point - Analyst*

PRESENTATION

Bob Flexon *- Dynegy Inc. - President & CEO*

Good morning, everybody. Thanks to everyone for coming. And safety is such a core value at Dynegy, I don't want folks to look at this room and think this is how we typically run our business. I think we put every tripping hazard we possibly could -- a lot of congested chairs, monitors, stage, so just please be careful as you try to navigate the room here.

Over the course of the day you're going to hear from the management team and I'll kick it off and then following me will be Carolyn Burke, immediately to my left, who will cover the integration, PRIDE and synergies. Julius Cox, to my right, will do the regulatory overview. I'm zigzagging here because when we had rehearsals watching Julius and Jeff Coyle get by each other on the stage, it wasn't pretty, so we had to separate. So Jeff Coyle is going to be doing the operation support after Julius.

Then we're going to take a break. I'm sorry, right before the break we'll do a quick Q&A. And in the Q&A what we are going to attempt to do is focus it on the topics that were covered primarily by Carolyn, Julius and Jeff. And then after the break we'll come back with Sheree covering retail, Hank on commercial, Clint on financial. I'll do a wrap-up and then we'll have a Q&A session that will cover any topics that you like to go through.

So with that will get into the presentation. Our first Investor Day meeting was held on January 13 of 2013 and Dynegy at the time was a very different Company. We think today that our generation portfolio since that time has increased by 16,000 megawatts. PJM is now our largest market rather than MISO and our combined cycle fleet has more than doubled in size and we now have the largest -- we are now the largest merchant combined cycle fleet in PJM and ISO-New England.

EBITDA in 2013 was $227 million and back then we identified a path at our meeting on how we could reach $500 million in EBITDA. The levers at the time that we saw that we needed to achieve that level was executing around PRIDE, the expected impact that we felt was forthcoming around retirements and the impact that would have on energy prices and capacity prices, reaching a settlement in California for the [tolling] agreement that had previously been canceled and probably most leveraging was how can we effectively allocate capital through the balance sheet capacity that we had that was a result of our restructuring.

So now in 2015 after we've executed in these areas, EBITDA is expected to be more than 300% higher than what it was in 2013. That more than doubles the $500 million target that we had put out there on an annualized basis. And during that same time period, our share count has only increased by 28% or 40% on a fully diluted basis.

At our 2013 meeting, we also identified we needed to develop and start a retail business. We were starting from Ground Zero on retail. Today our retail business serves over 22 million megawatt hours of load per year and it provides a very cost-effective hedging for a portion of our wholesale fleet while adding incremental earnings and EBITDA.

So Dynegy today is no longer dependent on just two assets. Our portfolio today offers several advantages versus what we had in 2013. We've increased the combined cycle portfolio from 4900 megawatts to over 9900 megawatts. Our capacity revenues in 2016 will represent approximately 32% of our gross margin versus 12% in 2014. And we have a lower cost generation fleet as a result of unequaled access to low-cost fuel and then the efficiencies that we've developed through our PRIDE program.

So while much has changed since January of 2013, our investment thesis at Dynegy remains the same. We're an attractive value-oriented investment opportunity with a very compelling risk return profile. The portfolio has multiple avenues for upside from having high-quality assets in markets where supply is contracting, market reforms are now taking place and improved capacity values and higher energy prices are now being realized. And PRIDE keeps us focused on improving the value of our fleet.

Access to lower-cost fuels due to our advantaged locational position of the gas fleet to the Marcellus and Utica reserves and the lower delivered coal costs that we have for our coal fleet provides a layer of protection from downside risk that enables our portfolio to generate very positive cash flows in virtually any natural gas price environment.

The expected free cash flow generation from the portfolio over the next three years is expected to be about $2 billion and allows us to meet our obligations while having access to substantial discretionary capital that can be allocated to what we view as the best risk-adjusted return opportunities. This includes returning capital to shareholders.

In 2013, the anticipated market catalyst that we saw forthcoming was the structural changes taking place to generation supply leading to tightening reserve margins. We are now in that cycle where coal-based generation and to a lesser extent nuclear assets are being replaced by natural gas fire generation and renewable generation, so 2015 really brings a very substantial change in generation mix.

2015 will have the most coal retirement ever and that's primarily in the markets in which Dynegy participates. It will be the most gas burn for power generation that's driven across all markets and this will be the year that will have the most renewable build ever and that's primarily concentrated in the Southwest and the West which is away from Dynegy's core portfolio.

So these changes have created a more volatile and a less stable power market and we anticipated this as we approached 2015. We deployed our balance sheet capacity to reshape our portfolio by expanding into markets where these fundamental changes were occurring. We increased our gas-fired generation assets in markets that have well defined capacity markets leading to a more balanced revenue mix from the portfolio.

So while 2015 will likely be the watershed year of change, there's a second wave of retirements that we see coming. With the declining reserve margins, ISO-New England and PJM have both recognized the need for what we refer to as quality megawatts. These are megawatts that can be relied upon for reliability to meet the most challenging events and conditions. These performance incentive reforms in these two markets reward the overachievers and it penalizes the underachievers.

So older assets, or assets that do not have certainty of fuel supply, or long ramping time, intermittent assets and demand response will be facing increasing pressure to meet the same standards as traditional fossil fire generation and nuclear generation or be forced to exit the market.

They'll either need to exit the market due to lack of compensation or to avoid the risk of the penalties. So this is going to put additional pressure on reserve margins benefiting generators like Dynegy that have a portfolio that can meet the stricter standards. We can capitalize on this through better plan availability that Jeff will be covering later this morning and through lower-cost expansions and uprates, which both Hank and I will be discussing.

So as I touched on earlier, our portfolio today has far greater an unequaled relative presence in PJM and ISO-New England, arguably the most attractive markets for an IPP that's giving the market fundamentals and reforms that are underway. Our expansion into these markets in advance of the market reforms is very well-timed. In addition as Hank will cover, MISO capacity remains tight and potentially may lead to capacity prices clearing at administrative caps similar to what ISO-New England experienced.

As compared to January of 2013, the demand for Dynegy capacity in MISO has significantly increased as has the prices the counterparties are willing to pay. If the overall system in MISO experiences a shortfall during the annual capacity auction, the administrative cap for MISO is about $250 per megawatt day.

As I highlighted on the prior slide, Dynegy has a differential exposure versus its two closest peers to higher capacity revenues via our relative position in PGM and ISO-New England while having no ERCOT exposure and minimal California exposure. And with approximately one-third of our gross margin in 2016 coming from capacity revenues this allows us to carry a more open energy position, which is consistent with our view that power price volatility should lead to higher energy revenues.

So when we originally launched PRIDE in 2011, we had a goal that was twofold. First, develop the internal skill sets to continuously innovate and improve the efficiency of the Company and drive higher cash flows, which is different from cost-cutting programs that others pursue. The second goal was to design and build a very scalable platform that could quickly absorb and serve as a platform for an expanding portfolio.

By the end of 2015, the cumulative compilation of PRIDE to EBITDA will reach $218 million. With minimal investment required, PRIDE projects have very compelling and very outsized returns and the doubling of our portfolio just two months ago offers areas of opportunities that we'll be announcing new targets for later this year.

Carolyn will show how leveraging our scale has led to significant reductions in our overhead costs per megawatt hour generated.

The integration of the Duke and ECP acquisitions is substantially complete. In just a couple of months, we absorbed two portfolios simultaneously doubling the size of the Company while continuously identifying synergies and capturing additional savings through PRIDE.

We had near flawless execution that we demonstrated our ability to quickly integrate and realize the benefit from these two transformative acquisitions. Carolyn will provide a more in-depth review of the integration status, the benefits achieved and the statistics that illustrate our accomplishments by our integration teams.

The glory part of M&A, which is the deal, isn't particularly unique from one company to another. Anyone can pretty much buy assets. What separates companies in an M&A process is the speed of the integration process and what happens after the deals close. At Dynegy we follow a very structured approach to find synergy and PRIDE opportunities.

We established a project in change management office to drive speed, to drive consistency and efficiency of the integration and we utilize dedicated, trained internal resources to perform our PRIDE projects and to perform the integration rather than handing the keys over to consultants.

PRIDE and our synergy projects are continuously tracked; they're audited and the responsibilities are assigned to the highest levels in the Company, so the very individuals that are here with me today.

Reliability is a key focal point of our PRIDE efforts offering substantial upside through increased plan availability. Our units have been benchmarked against similar units and we target top decile operating performance when compared to peer units. The Zimmer coal plant that we acquired from Duke has the most potential gains that we can make through improved reliability. Our portfolio has locational advantages for fuel sourcing.

The gas fleet with its access to Marcellus and Utica gas procures a substantial portion of its natural gas requirements at locations that have a negative basis to Henry Hub which results in higher spark spreads. The coal portfolio also benefits from access to lower-cost fuel utilizing PRB and Illinois basin coal as well as the favorable coal transportation contracts that we're able to negotiate with the rail companies as a result of our scale.

The Environmental Compliance rules recently, or about to be connected, that are the most impactful to the Company's assets and environmental spend are the 316(b) Rule which deals with water intake, effluent limitation guidelines, which addresses wastewater streams and coal combustion residuals rule for the treatment of handling of coal ash and ash impoundments. Jeff will provide the detailed discussion on the impact of these rules and our compliance plans.

The expenditures associated with these rules will occur over many years and into the next decade. Over the next three years, the expenditures are not significant and overall very manageable given the Company's outlook for free cash flow generation.

The portfolio's access to lower-cost fuels, greater exposure to capacity markets, cost and reliability benefits driven through PRIDE and manageable CapEx spend results in positive free cash flow generation in a wide range of commodity environments. In the current commodity environment, our combined cycle units in PJM and ISO-New England run as baseload units with high-capacity factors similar to our baseload coal unit.

Within PJM as gas prices climb from current levels, any reduction in the capacity factors of our combined cycle units will be offset by higher margins from our coal fleet. And to the extent there are natural gas price declines, the spark spreads of the gas units in PJM would likely expand offsetting lost margin from the coal units. The PJM portfolio as constructed imbeds a natural hedge providing protection in a falling commodity environment. The MISO coal fleet as in prior years continues to be the major beneficiary of rising natural gas prices.

As we assess our future capital allocation alternatives and plans, we do so with confidence of maintaining a strong balance sheet and liquidity position that is within our targeted metrics with ample liquidity to meet our daily operating needs. Clint will address our balance sheet management later in the presentation.

So as we evaluate capital allocation alternatives there are a series of low cost and high return expansions in uprates in our core markets. Dynegy is GE's largest LTSA customer and we've developed a very effective partnering relationship with GE that has created several of these uprate opportunities in our combined cycle fleet.

And within MISO, we are just days away from bringing 235 megawatts of combustion turbines online at a cost of less than $5 per KW. This is comprised of five mothballed peaking units that were part of the IPH acquisition and they will be able to sell not only into the MISO market but also to two other adjacent markets.

In PJM, New York-ISO, and ISO-New England, several of our existing combined cycle units are set for uprates adding an additional 450 megawatts at a fraction of new build costs and in significantly less time. In some instances, the capital that's associated with these uprates is deferred beyond the completion of the uprate.

We recently acquired the development rights to Burke Hollow. It's a 750 megawatt fully permitted site that's on the same plot of land as our Ontelaunee plant. No decision has been made at this time to initiate construction. Our immediate objective was to obtain the option as we assess the opportunity. Having an existing 550 megawatt unit on the same site brings economies of scale that no other competitor would have thus presenting a very attractive investment opportunity for the Company to consider.

Much of the Company's success since 2013 can be attributed to the prudent allocation of capital and over the next three years we estimate that as much as $2 billion of cash will be available for allocation. Safety, environmental and reliability investments remain a first order of allocation. Our PRIDE investment opportunities have very compelling IRRs and short payback periods and require limited capital investment.

The vast majority of the unallocated cash will be used for share repurchases or discretionary investments to the extent that the discretionary investments have a return profile that exceeds that of share repurchases on a risk-adjusted basis.

Debt levels will continuously be managed to the targeted metrics that Clint will be covering and once we get through the summer season and the upcoming capacity auctions in PJM, we'll be better positioned to formally announce and initiate the first phase of our capital allocation plans.

While Dynegy's equity price has dramatically outperformed its two closest peers since the 2013 investor meeting, the outlook remains equally bullish. So when taking into consideration the markets that each of the companies have exposure to combined with the quality and the quantity of the assets in these markets that Dynegy's valuation by comparison is inexpensive.

The free cash flow yield which potentially reaches the midteens provides a solid footing for further share price appreciation over the forecast period.

And Dynegy has become much more than a natural gas play and to illustrate this on January 17, 2013, the [Valve 13] natural gas strip was $3.67 per million BTU. Today the settled [Valve] 15 natural gas strip is $2.86 per million BTU, which is 22% lower. Our equity performance over this same timeframe increased approximately 66% where the share price of our other two closest peer companies Calpine and NRG have essentially achieved no price appreciation.

Our portfolio additions in attractive markets with locational advantage, generation asset retirements, capacity market reforms, our self-improvement efforts through PRIDE and synergy capture are not dependent on natural gas to drive value. Earnings in free cash flow growth is being realized from a series of different catalysts many of which have now been triggered.

And without new generation in the intermediate term to offset the retirements that are now occurring within our core markets, the fundamentals for the Company are very promising. Our coal generation fleet continues to provide substantial upside in a rising natural gas market where our gas fleet with its locational advantages provides substantial cash flows in the current natural gas environment.

So as we go into the various presentations today, the theme of a transforming marketplace coupled with the regulatory environment will be highlighted several times. Our portfolio has been shaped and positioned to be a beneficiary of these changes.

PRIDE continues on and later this year we will launch the next chapter of PRIDE with new targets and with upwards of $2 billion of cash expected to be available for allocation over the next three years, we look to build on our track record of creating shareholder value by prudently allocating capital to the best risk-adjusted return opportunities.

Now I will hand it over to Carolyn who will talk about the integration of synergies and PRIDE.

Carolyn Burke - *Dynegy Inc. - EVP, Business Operations & Systems*

Good morning, everybody. My name is Carolyn Burke. I am currently the Executive Vice President for Business Operations and Systems. Most recently though I ran the integration for the EquiPower and Duke assets and that along with PRIDE and the synergies is what I will be speaking to you about today.

Now I know you'd like me to all just jump straight to the synergy numbers but please let me take you through our approach to the integrations. It is because of the approach that we employed with the integration that we feel so confident in our ability to capture the synergies that we're announcing today. The primary reason many M&A deals do not deliver longer-term value is because they fail to integrate the hard assets, the systems and the plants with the soft assets, the people and the process in a timely manner.

They fail to leverage the timing, momentum and excitement around a transaction, i.e., they just take too darn long. And when it takes too long, it adds cost, it adds complexity and it adds uncertainty to an organization.

A couple of points on this slide that were particularly leveraging to us. Speed over elegance. We always planned for a December 1 Duke and a January 1 EquiPower go live date. While aggressive, we were ready on those dates and the fact that we had more time simply meant that we were more ready.

We accelerated certain system conversions and shortened the transition service agreement with Duke from six months to three months. This not only decreased the amount of cost by 50% to less than $3 million, but it accelerated the change in management that you need to achieve the synergies. And it let us focus on exactly that, achieving synergies.

Dedicated IMO teams; our first priority was maintaining our core business. We did not want the integration to distract us from running our legacy plans and commercializing the assets with the same level of excellence that we did before the integration. As such, we set up dedicated teams to focus on the integration and backfilled where necessary.

IT strategy; we actually defined our IT strategy during the due diligence period, i.e., before we even announced the acquisition in August. A key philosophy for us at Dynegy is one team and one goal and as an integration team, we added one system. We live by this religiously. We will not maintain more than two systems for any significant period of time. It's costly, it prevents the changed management that you need and it does not allow for a scalable platform for future growth. As of July 1, we will go down to just two duplicative systems and they will both be eliminated by year end.

Slide 23 describe some of the activities and the goals of the integration team. We had one primary goal, no disruption to the business. And on day one, our traders traded, our plants operated, the accountants started closing the books on Q1, and communications between the ISOs, the plants and our commercial floor flowed smoothly. Yet behind the scenes, we had converted over 118 system applications, with just five applications not fully converted. And again on July 1, we'll be down to two.

On the employee front, we had on-boarded and trained nearly 1000 employees onto our platform and onto our systems and today we have a retention rate of 99.4% and we intend to maintain that.

On the commercial side, we moved over 3000 trades and 150 wholesale contracts yet day one was like any other day and the last three months have been just like that. Given this sort of seamless cut over, transition costs tend to be low and in this case again, less than $3 million.

This discipline has also served us very well with our PRIDE program, which has reaped significant benefits to the bottom line. On slide 24, we show the trends in O&M and G&A costs in 2010, the original baseline year for our PRIDE program through an average of our planning horizon, 2016 to 2018. From 2010 through 2013, we focused on streamlining our G&A costs through a variety of PRIDE initiatives.

We reduced our real estate footprint; we decreased our burden costs and we maintained a flat organizational structure. We've carried each one of these initiatives through each acquisition and our overall G&A per megawatt hours has been reduced by 70%.

That same vigilance on cost effectiveness is applied to our O&M costs. Here too despite the swings in outage costs, the trend is favorable over the 2010 to the forecasted planning period. Similar to G&A spend, the initial O&M reductions were focused on reducing non-value added spend through a variety of PRIDE programs.

We consolidated regional offices, we reduced plant insurance premiums and property taxes, we renegotiated certain water contracts and we looked at our outage spend very carefully. In 2014, we began to see the favorable impact of the increased scale with the IPH acquisition and in addition to that, the successful renewal of our coal co union contract.

In 2016 and beyond with the ECP and the Duke acquisitions, our portfolio and cost structure is benefiting from a less cost intensive gas fleet balancing out our coal fleet and maintaining a relatively flat O&M cost structure.

It is important to note that you do not see a 70% decrease in O&M like you do in the G&A. Rather we leverage our PRIDE savings to offset other investments and other increases in our plants to maintain the reliability and safety and that's why you see a much more moderate 10% reduction over the same time period.

So now I can move on to synergies. We are very pleased to announce that we have increased our EBITDA synergies today to $130 million. At the time of the announcement, we had identified $40 million in EBITDA improvements and had assumed the elimination of all Duke corporate G&A. The $90 million increase is driven primarily by the improved rail pricing at three of our coal plants as well as the associated gross margin from those plants thanks to the improved dispatch due to lower fuel costs.

Additionally, we have included approximately $20 million in gross margin from various uprates at our newly acquired PJM and New England-ISO CCGT plant and another $10 million in gross margin due to the improved reliability at the acquired fleet.

Given the ongoing PRIDE program, we wanted to clarify how we're managing synergies versus PRIDE. First, we're tracking synergies very similar to PRIDE, fixed cash costs, gross margin improvements and one-time improvements in the balance sheet.

Synergies are improvements that will be realized during the time period of 2015 through 2018 and have been identified as of today, June 25. Now we will of course continue to look for improvements in the newly combined businesses but any project that's identified after today will be labeled PRIDE. And we will report progress on both our synergy targets and our PRIDE targets at the next earnings call. We will also announce PRIDE targets at the third-quarter earnings call for 2016.

There are a number of projects that we have identified through the synergy program that have not yet been fully vetted or quantified at this point. Refined coal is a perfect example. We will begin testing refined coal at the Ohio plants over the coming months. In 2014, refined coal brought $14 million of improved EBITDA to the IPH fleet and an additional $4 million to the coal co fleet, again in 2014. In 2015, we're actually forecasting an incremental $10 million of improvement to the coal co plant.

If testing proves out at the Ohio plants, we would announce that improvement through the PRIDE program. Other projects under study include changing the fuel mix at our Ohio plants and reviewing the barge transportation rates.

Finally with the exception of the LTSAs, we have yet to complete our review of the combined fleets' purchasing power but we do know this, our annual non-labor O&M and CapEx spend is nearly $650 million. If we target just 3% of that in savings, which is significantly below the benchmark for most M&A transactions, we would be looking at another $20 million of improvement. So more to come at the third quarter earnings call on that.

Slide 26 provides a breakdown of the breadth and depth of the synergies. And again, I will just highlight a few things here. In the by source category, the fuel and fuel transport includes the coal contracts and the improved dispatch that I spoke to earlier but it also includes improved gas contracts and pipeline optimization projects. These savings are largely due to our increased purchasing power and taking advantage of the proximity of our plant sites.

Procurement synergies are savings from renegotiating better rates at our plant insurance providers and our LTSA provider. With the LTSA renegotiations, Marty Daley and his team have done an absolutely fantastic job in securing major savings for our newly acquired CCGT fleet. There's a $9 million benefit in maintenance CapEx and O&M. There's another $10 million in improved gross margin from the increased dispatch thanks to the lower cost structure and there's approximately $25 million in reduced future outage spend.

Additionally, collateral outstanding to our LTSA provider was reduced by $120 million, previously announced as part of our balance sheet target.

Finally, by leveraging the combined fleet in the LTSA renegotiation, we are on track with 260 megawatts of uprate projects at our newly acquired New England-ISO and PJM gas plants. Hank will speak to those later in the presentation.

But please note any uprates associated with our legacy Dynegy plant will be part of the PRIDE program. They are not part of the synergy program.

The by status category, what does this mean? The 75% of our synergies are secured. That means all actions have been taken and there is little to no risk that we will be able to achieve these synergies. We've signed new contracts, we've implemented any changes in our operating procedures and we've received any necessary external or internal approvals.

The remaining 25% of the synergies we consider identified and in process. We have quantified the synergy and we've initiated steps to achieve it but the synergy itself is dependent on forward pricing and the final favorable impact will not be known until sometime in the future; for instance, the value of the uprates in the PJM performance capacity market.

Cost to achieve these synergies are reasonable. In 2015, approximately half of the $31 million is related to severance and the other half is related to uprate CapEx. The balance in 2016 forward is all driven by uprate CapEx. The majority of our synergies requires little to no investment.

So in closing, I just want to reiterate that we have executed on a very complex transaction, closing two transactions back-to-back with no disruption to the business. We have leveraged our platform with the additional scale and we have confidence that it can manage the forecasted growth in both our retail and our wholesale businesses. We are on target for $130 million in EBITDA and $375 million in balance sheet synergies, significantly beating our earlier expectations and we will continue to carry on the work in our synergy program well into 2016 and beyond with our PRIDE program.

With that I'm going to turn it over to Mr. Julius Cox and he'll cover regulatory policy.

Julius Cox - *Dynegy Inc. - CAO*

Thank you, Carolyn. Good morning, I'm Julius Cox, Dynegy's Chief Administrative Officer. Our approach to regulatory remains consistent. We want to focus our efforts on helping to make appropriate environmental policies and advocating for constructive market design. We accomplish this at the federal, state and local levels through advocacy, outreach, education and by forming partnerships with our peers and other key stakeholders.

As this slide shows, there are a number of examples of how our regulatory efforts have had a positive impact on our business. We've been active in both Illinois and Ohio in terms of advocating against out-of-market subsidies.

In Illinois, we took on the responsibility to educate consumers and policymakers through our PR campaign and by putting boots on the ground at the state capital. In April, Bob and our regulatory team met with state legislators. We wanted to provide a dissenting view to Exelon's request for out-of-market subsidies, which we believe would have a destructive impact on the market. We've also proposed broader solutions for the state of Illinois, which I will cover a bit later.

In Ohio, we provided a drastically different and a much more bullish view of their competitive market. We believe these efforts help to create an extremely high approval bar for AEP and FE to overcome in their request for out-of-market PPAs.

In MISO, we're continuing to bring attention to the need for market reform. Our team has continued to educate stakeholders on a number of key issues including the fact that electricity rates charged by regulated utilities include capacity costs of nearly $300 per megawatt day. We've also worked to educate MISO and state officials with respect to the fact that while Zone 4 separated in the most recent MISO auction, the results are very much consistent with competitive markets, including those in PJM.

Here's another way to think about how an effective regulatory function should set its priorities. We protect the interest of our business and investors by making an impact on markets and policy matters that drive costs and revenues. Previously we've talked about our efforts and the potential impact at Dynegy with respect to pending regulations, market design changes and supply/demand fundamentals.

As this slide shows, a number of things that were previously unknown are now known. For example, we're now in the compliance stage for both MATS and CCR and market design changes in PJM and ISO-New England have now occurred. We want to ensure that competitive markets are preserved and that environmental policies don't place an inappropriate burden on our business.

Let's talk about MATS for a moment. The only story with MATS is that there really is no story. As the chart on the right illustrates, the amount of megawatts that are set to retire this year nearly equal the total number of megawatts retired in the previous three years combined. Additionally, plants located in PJM that are set to retire have not participated in any recent forward capacity auctions.

Now the most recent information we have about MATS is that the Supreme Court ruling could be issued as early as this morning. But our belief is that these plants have retired or soon will retire and we don't believe that the Supreme Court ruling will have a significant impact on this.

The real story with respect to plant retirements is that beyond MATS, as Hank will talk about a little bit later, is the second wave of retirements that will be driven by things like the risk of not performing in PJM under CP. For Dynegy, our reliable and well-run fleet is set to capture the opportunities MATS has created with respect to tightening energy and capacity markets.

We've included ELG here since the rule is not yet finalized. This serves as another illustration of where our repertory efforts are focused in helping to develop appropriate policies. We're actively engaged in helping to shape the final ELG rule by providing comments to the US EPA and our advocacy efforts through our trade associations. With ELG expected to be finalized in September, we will soon move to the compliance stage. In a moment Jeff will provide an update on our spend profile and as he will show, we believe the assumptions we've made remain consistent with prior expectations.

As currently proposed, the Clean Power Plan contains a number of points that we believe to be unworkable. For example, improving coal plant heat rates by 6% is not technically feasible. Additionally, the plan would likely result in several unintended consequences with respect to state emission limits. As this illustration tries to show, neighboring states like New Jersey and Pennsylvania have vastly different emission rates. Even when you have plants on other side of the state line, they are separated by less than 10 miles.

Now that would actually benefit our Ontelaunee and Liberty plants that reside in Pennsylvania because they would be in a position to export power into PJM. But the result of the current proposed emission limits will likely result in shifting generation and jobs from one state to another without having much of an impact on lowering CO2 emissions.

With our reshaped portfolio -- while the inconsistencies in the plan fail to be addressed, we are positioning Dynegy to manage any risk. With our reshaped portfolio, a much larger percentage of our fleet is in areas like Pennsylvania and New England where we believe the emission limits can be more reasonably met.

Additionally, our strategy for beneficial reuse of CCR serves as a program to offset CO2 emissions. And we continue to work within key states to identify appropriate compliance pathways.

As Bob covered in his earlier remarks, with 90% of our generation in PJM, ISO-New England, New York and MISO, Dynegy is the IPP best positioned in the highest value markets. For regulatory, this heat map serves as a roadmap for how and where we should focus our time and resources. The map helps to highlight gaps that we should be working to address in the markets where we operate.

Along those lines the next few slides talk about market design in the two markets we have our largest concentration of megawatts, that's PJM and MISO.

As many anticipated a few weeks ago, FERC accepted Capacity Performance in PJM. Given our deep presence in PJM, it comes as no surprise that we were strong proponents of CP. To this end along with one of our peers, we jointly filed comments in support of CP. We also met with FERC's staff to discuss the proposal prior to its initial filing.

Now there has been some concern about the impact the balancing factor would have on Capacity payments under CP. But even with a balancing factor of 85%, the default offer cap is still likely to be more than $270 per megawatt day.

With our diverse and reliable portfolio in PJM, we're in a better position than any other IPP to capture the upside CP provides for reliable performance.

Here's where the leverage of our PJM portfolio is realized under CP. As you can see in this example, under a forced outage scenario that lasts 8 hours, an owner with a single plant faces a penalty of nearly $16 million. That penalty then gets shared as a bonus by plants that are over performing.

Under the same scenario if you have a portfolio of plants even with a plant that is underperforming, plants that are overperforming are in position to receive a bonus. In this example, the overperforming plants share in the bonus which helps to offset the penalty incurred by Plant A.

Now there are countless scenarios under CP but the point here is that having more plants allows you to mitigate risk and provides more opportunities to be rewarded.

It's also important to consider CP as a potential barrier to entry. Financing new build in PJM may be more difficult given the downside risk of not performing under CP. And with our fleet of 60 units across PJM, we have a diverse and reliable portfolio that will mitigate risk and allow us to capture additional opportunities for upside.

Let's shift gears and talk about MISO. As you are likely aware, the MISO default offer cap link to PJMs RTO capacity price. For MISO, this is meant to represent the lost opportunity cost of not exporting capacity to PJM. As you can see on this slide, the starting point for MISO's 2016/2017 planning year reference point is the RTO clearing price in PJM's base residual auction.

Now taking the current RTO clearing price for 2016/2017 and using last year's transmission cost of $19 per megawatt day, you get a reference price of about $80 and a default offer cap of about $100 per megawatt day. But a few points to be made here.

First, either the incremental or the transition auction in PJM may clear above the BRA. And under the tariff, the MISO Market Monitor has the latitude to reassess the reference price under a variety of circumstances.

Secondly, [as a net] increase we will request to make facility-based offers in excess of the cap and our commercial and regulatory teams are working to evaluate the exemption request process.

Finally, as Hank will address in more detail, if reserved margins at MISO for the 2016, 2017 planning year continue to decrease and the system is short, the actual clearing price of next year's auction could result in CONE, or nearly $250 per megawatt day.

We've been increasingly [commenting] to the market dynamics in MISO. Illinois is the lone wolf in terms of market participants. It is surrounded by vertically integrated utilities in the other 14 MISO states. And as I mentioned earlier, regulated utilities in MISO earn on average more than $300 per megawatt day for capacity that's baked into their rates. These utilities do not rely on the auction as an economic mechanism. Instead, utilities use the auction to balance load and demand, so they bid everything in at zero to ensure all megawatts clear the auction.

In Zone 4 as this chart illustrates, we estimate our weighted average capacity price of less than $60 per megawatt day. But the real story here is this, if you take the clearing price of $150 per megawatt day and southern Illinois, as well as the $136 per megawatt day in northern Illinois PJM and contrast that against the $300 per megawatt day that vertically integrated utilities are receiving for capacity, that's a signal that competitive markets are actually resulting in lower prices for consumers. But it also highlights the inconsistency in the MISO market construct and we believe that this uneven playing field has to be addressed.

Finally, despite the potential for reserve margin shortfalls, MISO's capacity market does not send us effective signals to incent new build. Given these factors in the longer term, the status quo market construct in Illinois needs to be improved. If Illinois wants to ensure that it has a [new] generation at reasonable and just rates for both consumers and suppliers, we believe there are number of options that should be considered.

Illinois is caught in the middle between a regulated utility model and a competitive market model. The current hybrid market construct faces a number of challenges. Last week Bob spoke at MISO's annual meeting continuing to highlight these very same points and we will also outline options that should be considered.

One such option would be for Illinois to move back to a fully regulated model. Obviously this is not our preferred option as we continue to believe that competitive markets are more efficient and deliver the lowest cost to consumers. But you can't ignore the challenges of the hybrid model and the increasing volatility it exposes consumers to.

Ideally Illinois will move to a completely competitive market model and this could be accomplished in a couple different ways including by moving southern Illinois into PJM. This would allow all of MISO to be on a vertically integrated model while also putting the entire state of Illinois under the same market construct.

Another Illinois only solution would be to create a Zone 4 capacity construct and while there are a number of things to consider with pursuing this path, it would serve to recognize the unique and competitive nature of Zone 4 as compared to others.

Under either scenario we believe that preserving competitive markets reward the most effective suppliers and results in lower prices for consumers. And while we remain bullish about tightening capacity markets in Illinois, the status quo is not sustainable in the long run. If change doesn't occur, the result will likely be increased risk of further retirements which will only serve to create even more volatility for consumers.

In closing, for Dynegy our regulatory rule is to advocate for constructive market design that supports competition. We protect the business by engaging key stakeholders in developing policies that result in appropriate environmental regulations. We focus our efforts on the markets where we operate like PJM and ISO-New England which provide for upside with their market design and in markets like MISO where we will continue to encourage taking the necessary steps to address any gaps.

With that I will turn it over to Jeff Coyle to cover operations support.

Jeff Coyle - *Dynegy Inc. - VP Operations Support*

Thank you, Julius. Good morning, everyone. I'm Jeff Coyle, Vice President of Operations Support. My team provides services to the generating fleets in the areas of safety, environmental compliance, marketing of CCRs, and reliability and today I would like to give you our status and our plans in these areas.

Let me start with safety, which is our highest value at Dynegy. Dynegy has been on a track of improving performance in this area with an exception in last year when we went from top quartile performance down to average performance in our industry. This was unacceptable to us and we've invested significant effort to understand and to address the situation.

Our safety incidents continue to be mostly sprains and strains and most occur when employees are performing routine tasks, ones they do regularly and repeatedly. We conclude that we do a pretty good job on the complex involved tasks that we do but sometimes we let our guard down on the day-to-day activities. In response, we focused on complacency awareness and injury prevention for our personnel in our plants.

We've also addressed -- placed additional emphasis on summer preparation and winter preparation for safety in our plants. And as a result, we had no weather-related incidents in the past year and for the first time in our recollection, no injuries from slips on ice and snow.

Another important initiative for us is obtaining voluntary or OSHA voluntary protection program status for our facilities. We presently have six sites with this certification, an additional six sites that have either made their application or in the process of application. We think this is important because it requires plans to have and to demonstrate an excellent program for safety and health that involves both management and employees.

Only a small percentage of power plants have this accreditation and they typically obtain a lost workday incident rate less than 50% of industry averages.

Today we're not yet achieving our goal of top decile safety performance but we do believe that we will get there with a consistent program of continuous improvement and proactive efforts.

Let's turn to reliability. Reliability is also another key initiative for us. Our gas plants have performed very well in the area of reliability with historic equivalent availability performance in the upper 80s and lower 90s and end market availability in the mid to upper 90s.

The units recently acquired from Duke and ECP also have a similar performance history. For this fleet, we're targeting equivalent availability to be above 90% and end market availability to be 98% for both of these fleets, or all of these fleets through the end of the decade and we'll continue to invest in the units to achieve this objective.

Moving to coal, in 2014, coal segment performed a detailed benchmarking of their units against industry and determined that while some of the units also performed very well against their peers, there were some opportunities on specific units. As a general rule, 90% equivalent availability for coal-fired boilers constitutes top decile performance against their peers of similar size and type.

As a fleet, the coal co units have performed in the mid-80s. IPH units have performed typically in the low 80s and legacy Duke fleet in the low 70s.

Last year we looked and identified several high payback projects that we could advance into the year. IPH was in their first year as part of Dynegy became much of that opportunity. From our initial work on this fleet, we saw equivalent availability improve by 3.4% over prior year results and that translated to an improvement of more than $6 million for the remainder of the year.

As we move into 2015, it's easy to see the boiler tube leaks on our coal-fired boilers remain our greatest opportunity area with losses here three times that of the next largest contributing factor. We calculate our opportunity costs for our legacy Dynegy and IPH fleets in 2014 was in the range of $44 million and of course this would move higher with the new plant additions that we've recently made. We are responding to this opportunity by working with the plants to perform a section-by-section review of each boiler to quantify the number, location and cause of the leaks that we've had.

We will use this technical information along with our commercial and asset management teams to assure that we have our resources properly prioritized and have the work reflected in our budgets and our outage schedules.

Additionally, our teams are exploring other timely repairs and operational changes to extend the life of equipment that will allow us to delay or negate near-term capital expenditures and the associated outages that go with them.

Overall, we are targeting to get our coal-fired fleet to 90% equivalent availability by the end of this decade.

Last year we also rolled out a fleet initiative for gas and coal to improve preventative maintenance activities. We started with our highest priority areas, which included safety, environmental compliance and critical equipment to assure we have right activities taking place in a timely manner. And when we talk about the critical equipment, those are the pieces that if there were a failure would constitute immediate production loss, either a forced outage or forced type of derate.

We completed our first work in 2014 and in 2015 and years beyond, we just continue to drill down further into our other systems and make our preventative maintenance systems more robust.

Now maybe this all sounds a little basic and in some ways it is but it does take the coordinated efforts of many to get this right.

Moving to environmental compliance, certainly in years past our focus has been heavily weighted toward compliance with a myriad of federal and state air in emissions regulations. We've invested in plant equipment and made operational changes and we're in compliance with the existing major rules. This compliance extends to the plants that we recently acquired from Duke and ECP.

Now our focus starts to turn to the three recent and pending rules: 316(b), ELG and CCR. The rules themselves, 316(b), also known as the water intake rule, is designed to protect aquatic organisms at plants that draw cooling water from lakes and rivers considered waters of the US. This rule was signed last April and requires compliance within two years after each plant's water discharge permit, known as the NPDS permit, is renewed.

Effluent Limitation Guidelines, what we call the ELG rule, sets more stringent guidelines on power plant water discharges. This rule has not been signed yet though we expect signature to occur on or before September 30 of this year.

And the Coal Combustion Residuals rule, what we call CCR, was signed last December and published in the Federal Register this past April. This rule regulates landfills and surface impoundments that contain combustion residuals and also defines the beneficial reuse criteria for these products.

Let's dive a little deeper into each of the rules. 316(b); our view of this rule remains essentially the same as last year but there are some positive aspects that I'd like to point out.

First, the majority of our fleet is already compliant. Our gas plants including our new acquisitions, utilize cooling towers and many take their makeup from municipal water sources which makes them exempt from the rule. For our gas plants that do draw from waters of the US, we'll need to perform some low-cost studies over the next few years but the draw rate and velocity of that water is so low that we don't anticipate any issues that will require mitigation.

Additionally, our Moss Landing gas plant will be compliant with 316(b) as it will already comply with the more stringent California Once-Through Cooling rule.

In total our view is that nine of our 35 plants will require some level of capital expenditure. These are the coal-fired plants without cooling towers located on lakes and rivers considered waters of the US. Last year at Investor Day, we estimated the cost of $50 million over a five-year period for this work. This year we're reflecting $60 million over a seven-year period with most of that spend occurring after 2019.

The main change in our number is the addition of work at our Steward and Kincaid stations which were recently added to the portfolio.

ELG; our view of this rule also remains essentially unchanged from last year. We believe the rule will issue with language similar to previous guidance provided by EPA. As a result of this, we also expect our compliance strategies to remain the same although we will have some additional work at our newly acquired plants. This rule applies to all plants but we do not anticipate mitigation will be necessary at any of the gas facilities.

On the coal side, you'll see on the slide where we anticipate capital expenditures will be required. Most of the costs will be associated a conversion of bottom ash conveyor systems from wet to dry operation on units that are greater than 400 megawatts in size. We'll also have some costs for treatment of scrubber wastewater on the wet scrubber systems located on the Ohio facilities.

In addition, we have a number of smaller capital projects expected to be $2 million or less per site that are shown as red crosshatch on the chart.

Last year we were estimating $125 million over a five-year period for this work. This year we're estimating $290 million over an eight-year compliance period with most of that spend occurring between the years 2018 and 2023. Again the main difference is the work required at the acquired coal plants.

The numbers in our budget exist today as engineering estimates and they are based on conservative assumptions. Once the rule is finalized, we'll begin to perform the detailed engineering and we'll refine our costs accordingly.

CCR; the clock for this rule began running on April 17 when it was published in the Federal Register. The final language in the rule allows us to demonstrate compliance of our impoundments for groundwater, location and structural safety requirements. Any site that meets the requirements can continue to remain open and receive material.

The slide on the screen shows the major milestones that are in front of us. 2015 starts off very busy as we initiate the key monitoring, record-keeping and reporting requirements. Our preparations are already well underway and we're on track to complete all of this required work. We're also now proceeding with analysis of structural integrity, groundwater and location restrictions that must be completed in years 2016 through 2018 respectively and we're also on schedule with this work.

So what does this mean for Dynegy? We have 46 CCR sites spread across our different coal plants. Three of these are closed or otherwise maintained facilities and are exempt from the CCR rule. They require no additional action or spend. Eight are landfills, typically newer facilities with liners. They'll need to go through the testing that was discussed on the prior slide but we believe they are low risk and will likely remain in service until they are fully utilized and are closed according to their original schedule. 13 are inactive facilities.

And we have some flexibility here around their closure. We will have a decision point in October where we can either elect to close some of these within three years to limit our exposure to future monitoring and maintenance requirements, or we can just take them through CCR analysis.

And then finally, we have the 22 active surface impoundments that are receiving CCR products today. These plus any of the 13 inactive facilities will go through the CCR analysis. Again, any site that passes its testing can remain open and continue to receive material.

If a site does not pass this testing, we have another decision point and can choose to either mitigate or proceed to close. At this time, we have not reflected any dollars in our budget to mitigate the issues. Without the analysis in hand, we simply can't reasonably estimate these costs.

However, we may find that some mitigations are prudent and will allow the impoundments to stay open and defer the asset retirement obligations for closure to a later time.

You can see we have a lot of work ahead of us and that's why we're are getting an early start on our testing. If we determine impoundments need to close, we have time to mitigate or make alternative arrangements for the CCRs without the detrimentally impacting plant operations.

This next slide summarizes the key assumptions and points from the environmental section. Overall we're estimating approximately $108 million of spend between years 2016 and 2018 and approximately $600 million in spend between years 2019 and 2023. These numbers contain our capital spend plus our asset retirement obligations for closures of the landfills and surface impoundments. We think this contains conservative assumptions and we may be able to reduce these project costs as we perform the detailed engineering.

We also believe the number of our impoundments will demonstrate compliance with the CCR rule and will be able to remain in service. And this of course will allow the associated ARO dollars to be shifted to a later time.

Coal combustion byproducts; before the acquisitions, our legacy Dynegy and IPH fleets produced about 1.5 million tons of coal combustion residuals each year and we were recycling about 30% of that total. Last year we announced our plan to beneficially reuse 100% of our CCR production by year 2020. This benefits us in multiple ways but especially by reducing the future cost for landfill construction and maintenance.

Our new acquisitions complement this strategy very well. Even though today's combined fleet produces 3.5 million tons of CCR annually, the group is now recycling 56% of that total production. That's mostly fly ash and gypsum today. In comparison you can see that the industry average is in the low to mid 40s.

By realizing our goal and beneficially reusing that additional 44% on top of the 56% used already, we can avoid approximately $30 million per year in future landfill construction, operation and eventual closure costs.

This year we expect to move at least 61% of our production and that represents 175,000 ton increase over last year and we'll keep stepping up from there as we develop additional avenues in the market.

To do this we have recently developed a CCR marketing team and have charged them with improving our CCR utilization. We've also tasked this team with the development of new product opportunities.

Last year I alluded to a potential product opportunity during my presentation and I'm happy to report back to you today that we've just signed an agreement with a third party to build a fly ash processing plant at our Duck Creek Station. We'll sell our ash to this vendor and they'll mill it to improve flow, strength and set time properties that are desired by the concrete industry. We believe this will help create a larger market demand and more movement of product into the marketplace.

Construction is slated to begin later this year and be in service by the second quarter of next year. Within three years, the vendor has committed to take 80% of the fly ash generated by Duck Creek Station. This will be a first of a kind system in the Midwest and based on our experiences from this system, we may also move ash from some of our other nearby plants through this facility.

Another expected benefit to this work is the carbon offset. We anticipate this milled product can replace up to 60% of Portland cement and concrete and since the cement manufacturing process itself creates significant CO2, use of milled fly ash can reduce overall CO2 emissions.

In summary, our team is actively responding to the requirements of the new and pending CCR and water rules. We're developing plans for all of our plant sites and we are on track with our planning and execution of the work. We don't envision any of these rules will negatively impact the operation at any site. The expected spend is manageable and limited to the near-term.

And finally, our CCR marketing team benefits Dynegy by requiring fewer future landfills to be constructed, maintained and eventually closed.

With that, I will turn the podium back over to Bob.

Bob Flexon - *Dynegy Inc. - President & CEO*

Thank you, Jeff. So what will do is we will spend about 15 minutes or so on Q&A that will follow it with a break. I would also say that available for questions, we have Catherine Callaway, our General Counsel; Mario Alonso, who heads up strategy and M&A who we're not going to let answer any questions; Dan Thompson, runs our coal operation and to my right we've got Dean Ellis who works with Julius on regulatory and Marty Daley, who does the gas operations.

So with that, I open it to the audience here for questions on the first half of the presentations.

QUESTIONS AND ANSWERS

Julien Dumoulin-Smith - - *Analyst*

Good morning. Julien (inaudible) at [UBS]. So first to touch on the capacity market development, I'd be curious, what are your expectations on the transition option. (inaudible) So I'd be curious what you expect for your portfolio, (inaudible) cleared, uncleared, etc.? And then on MISO if you could elaborate, what has enabled you to bid above the market level, if you could talk a little bit to the strategy (inaudible)?

Bob Flexon - *Dynegy Inc. - President & CEO*

Sure. On the capacity performance piece for PJM, Hank will get into more of that in his discussion. I think the high level response that I'd give you on that is that we're doing an asset-by-asset review and where these things clear and the like will always depend on how people approach the auction and bidding behavior. For us we have to bid all of our units into the CP -- the auction in 2018/2019, I guess for the transitional, it's voluntary whether you do or whether you don't. We plan to certainly bid in the majority. There's certain units that have access to fuel issues, particularly around the peaking units. And in any bids that we make for the capacity auction in 2018/2019 would be certainly risk adjusted.

We'd have to look at it from a standpoint of there are certain units that if they are going to clear, it is going to require either a level of investment or a risk premium in case it actually does clear. So a portion of our assets will be like that and if everybody takes a similar approach, then you would expect that you'd get some significant uplift in the market.

If others are in there just as basically price takers and think we will play the odds and hopefully there's a shortage event and I don't get hit by it, then you would have a very different result in the auction. But if you have a shortage event that lasts eight hours and you fail to perform, that's roughly an $85 per megawatt day penalty. So call it 16 hours, you're at 170. So the risk penalties are very significant so our view is that we're going to take it very seriously on a risk adjusted approach on how we bid in assets and whether others do that or not, we'll see.

For the transition auction again, a majority of our assets will be bit into it. Hank will talk maybe a little bit more about that when we come back to that later on in the final Q&A session to follow up on that.

On MISO, as Julius highlighted that for next year the MISO limitation around the adjacent market tariff is $59 plus the transport to get the energy in there, which if you do the math it's roughly $78 or so a megawatt day, would be the reference price. You can go for unit specific exemptions, things like take Newton scrubber as an example that has a large CapEx spend coming its way, so you can build that into an exception request into the Market Monitor.

And whether or not they approve it, it's up to them but we would look at each unit specifically as to its CapEx requirements, it's cash flow and we would make justification to the Market Monitor and they would have to decide I think within a certain period of time prior to the auction whether or not we get the exemption to bid above or not.

Hank, is there anything you would add to that or Dean or Julius --?

Julien Dumoulin-Smith - - *Analyst*

Maybe a quick comment to go with that. How much of your capacity (inaudible) tricky but could potentially clear the auction (inaudible)?

Bob Flexon - *Dynegy Inc. - President & CEO*

Are you talking MISO?

Julien Dumoulin-Smith - - *Analyst*

MISO, exactly.

Bob Flexon - *Dynegy Inc. - President & CEO*

How much can potentially clear?

Julien Dumoulin-Smith - - *Analyst*

Yes, exactly. In terms of what commitments again versus retail obligations, etc., how much --?

Bob Flexon - *Dynegy Inc. - President & CEO*

So I guess the length that we have right now for the capacity is about 80% or so for next year. Is it 60%, 80%?

Unidentified Company Representative

Yes, it's 60% to 80%.

Bob Flexon - *Dynegy Inc. - President & CEO*

If you think about IPH, IPH will have about 60% of its capacity spoken for via retail. And then the DMG fleet will be -- the legacy Dynegy coal plants would be largely open. There are some bilaterals that have been done. IPH has some wholesale contracts but I think between the two fleets you are probably around 60% -- 50%, 60% (inaudible) an auction. You look at this year we failed to clear about 3000 megawatts in the auction out of 6400 megawatts. I'd assume it would be somewhere in the same neighborhood as that.

Mark Fisher - *AF Capital - Analyst*

[Mark Fisher] with [AF] Capital. On the compliance side, the timeline that you are doing, does that dictate or is it similar at all to prior compliance deadlines where there are long lead times? In other words, is this something that your competitors are going to have to start thinking about for upcoming auctions?

Bob Flexon - *Dynegy Inc. - President & CEO*

Are you talking on the -- not the environmental compliance --?

Mark Fisher - *AF Capital - Analyst*

Yes, the three (multiple speakers) --

Bob Flexon - *Dynegy Inc. - President & CEO*

Oh, the environmental compliance. Yes, these are all dictated by statutory dates.

Mark Fisher - *AF Capital - Analyst*

In terms of spending though, are these similar lead-times that you've seen before?

Bob Flexon - *Dynegy Inc. - President & CEO*

Absolutely.

Eric Flown - *Goldman Sachs - Analyst*

Eric [Flown] from Goldman Sachs Asset Management. A question on the slide 38. Can you help us bridge your guys' expectations for the MISO reserve margin versus what came out two weeks ago as they are showing that that is probably not going to happen until 2020?

Bob Flexon - *Dynegy Inc. - President & CEO*

I'll let Hank provide a little bit of additional color on this and again he goes into it in his section but the high level is, MISO adjusted three things to take a deficit to a small surplus. They did the pencil whipping where you take your reserve margin and you lower it a little bit, so that gives you a little bit.

You take your demand growth and you lower it a little bit so that lowers demand and then they have capacity additions of about 3800 megawatts or so and of that 3800 megawatts, half of it is the new nuclear unit being built in Detroit in two year's time. They haven't broken ground on it yet so I'm going to put that in the somewhat skeptical category.

So you look at those three things, MISO is teetering on balance of whether or not they're going to have enough resources or not, and again there is no price signal to build and the way that MISO works and Julius certainly was covering this in that the market design where you've got 14 regulated states and you've got one that's a competitive state; the other regulated states they want to do their own resource planning.

And there really is nobody bringing the total picture together and the capacity auction within MISO has no economic incentive to actually spend the price signal other event in central and southern Illinois, so there's really essentially no new build underway.

They've got a fairly large queue, 63 gigs, I believe, of which I guess 18 or 19 have already been pulled out. But as far as the interconnection agreements, which is kind of where the ones that are real, that's the 3800. So we just view that MISO is just teetering on the edge here and they're relying on a lot of units that older peaking and the like, so we view that there's a real risk that the capacity is not going to be there on the highest demand days.

And even when I was at the MISO Annual Stakeholder meeting last week with the Market Monitors doing state-of-the-market report, he was expressing his frustration with MISO that you're not doing anything to fix this capacity market. There's no new price signals and if you look at the highest demand days that they foresee after giving credit to demand response and everything else, their reserve margin is going to this summer about 7%, 8%.

So you think about forced outages and the like -- it's a precarious balance that MISO has created and it's only going to get tighter because really there's nothing being built over the next several years there.

Greg Gordon - *Evercore ISI - Analyst*

Greg Gordon with Evercore ISI. On MISO and then back to PGM first, Julius, can you comment on the statements made by the Illinois -- I think it was the Illinois Attorney General (inaudible) being unhappy with the auction and what the next steps might be in that if there will there be a new process or not if there is (inaudible)?

Bob Flexon - *Dynegy Inc. - President & CEO*

I'll jump in in front of Julius. The auction results and this slide illustrates it particularly well on page 38, that you've got a market where every other surrounding state is incented to put their generation in at zero except for central and southern Illinois and this is where I think Exelon, Dynegy, the legislature in Illinois and MISO need to come together and fix the market for central and southern Illinois. Otherwise as days go on, generation in central and southern Illinois is such competitive disadvantage to those surrounding states it needs to be fixed. Otherwise central and southern Illinois are going to lose their tax base. They're going to lose a lot of jobs. You're going to see plants shutting down.

The Attorney General reaction to the auction where you suddenly see it going from whatever it was $16 a megawatt day to $150 and then they look at these surrounding zones and they see $3 a megawatt day and they think oh my God, something must be dramatically wrong; and it is. It's because these other 14 states are getting $308 per megawatt day. That's where the complaint should be.

But people don't necessarily understand the market. It's a bit esoteric in the way it all comes together and so they want to make sure that -- in deference to the Attorney General, she wants to make sure things were done the right way. We have experience working with Lisa Madigan; she wants to make sure that the proper procedures and protocols have all been followed, so they filed a complaint with FERC and we are going to respond to that complaint I guess in the next week or so.

Carolyn Burke - *Dynegy Inc. - EVP, Business Operations & Systems*

July 2.

Bob Flexon - *Dynegy Inc. - President & CEO*

July 2. But recall that both MISO and the independent Market Monitor, they're all over the whole bid process, the options, and they both have declared that everything was done completely within the tariff. So I don't see any risk or any issue from FERC or anything that deals with this particular auction. What it does serve is the catalyst -- let's make sure we have a full discussion around the market design in central and southern Illinois and I think there's a lot of parties interested in doing that now.

And at the MISO meeting last week, John Bair, who is the President of MISO, made the comment we've got the attention, we know we need to fix this -- let's go at it. They have proposals that they've made to Illinois that deal with treating Zone 4 differently than the other zones where it's kind of a PJM look-alike and it's probably the fastest thing you can do because actually moving to PJM would be much more involved and contentious to get it there.

So the fundamental issue is just you've got central and southern Illinois in the wrong market and we've got to do something to either synthetically improve that or actually move it.

Greg Gordon - *Evercore ISI - Analyst*

Thanks. Back to PJM, maybe just a question or clarification, (inaudible)

Jeff Coyle - *Dynegy Inc. - VP Operations Support*

I don't know if I understand the question. What type of unit?

Greg Gordon - *Evercore ISI - Analyst*

So just within the (inaudible) zone (inaudible) auction, the capacity price was [119], it was [59] (inaudible), but PJM has said that they are only going to clear one price. And so at 49.999% CP you need a [mac] unit to clear, one would presumably have to be at least a modest premium to 119. Can you comment on whether or not that's plausible?

Jeff Coyle - *Dynegy Inc. - VP Operations Support*

So the PGM rules are evolving as we speak. It's a very fluid situation and understanding from the meeting yesterday is consistent with yours that there's going to be one price. They'll be no zonal separation. And forecasting capacity prices was complicated enough before all this and now that -- but the volume part was pretty simple at least in our shop, we assumed all of our (inaudible) clear.

In the new environment you're not only trying to forecast pricing in a much more complex scenario where you can -- where you can (inaudible) individual strategies to take on risk, you also have the added component of the volume question. So there's a wide range of outcomes in the transitional auctions. We are going to know the answers to these things within five or six weeks and again I think the general view is that there is potential uplift and possibly meaningful uplift for the RTO section and the zones properties may or may not experience any uplift.

Bob Flexon - *Dynegy Inc. - President & CEO*

Greg, I don't see why it wouldn't be feasible. There's a fairly large risk premium you need to build in. There's been changes in generation mix. PJM West has had a lot of retirements. So again, it's all going to come down to bidding behavior but I don't see why it couldn't still continue to clear a strong (inaudible).

Michael Lapides - *Goldman Sachs - Analyst*

Michael Lapides of Goldman Sachs on equity research. (multiple speakers) Real quickly changing topic or changing region a little bit, first of all, New England. Where do you think we are in the cycle in New England given capacity prices cleared somewhere $9, $10, $11 a KW a month? Where do you think we are -- trough, peak, middle of the cycle type deal? That's the first question. Second question, can you address your outlook and more importantly your strategic plans for the California fleet?

Bob Flexon - *Dynegy Inc. - President & CEO*

Hank will go into ISO-New England. I'll just give a real quick answer on it. I think ISO-New England in the -- we are there in the cycle I put us somewhere between desperate and crisis. There's virtually no new generation being built. It's very hard to permit. If Northern Pass comes to fruition, it's going to be trapped in a new northern zone and the reason zones are created is to incent generation where it's needed and it's needed in South East Mass.

And with Brayton Point retiring, with Vermont and Yankee now out, ISO-New England I think very concerned about reliability in meeting the capacity needs in the southern portion, southeast portion of the state. It is not looking any better. There hasn't been much -- been cleared. I know in our meetings with ISO-New England they're concerned about liability and I think really the bellwether what tells you that is still they are doing the out of market type mechanisms to try to drive reliability by making payments for having excess fuel on-site and the like to run units.

They're relying on 25% of their generation fleet is old peaking units. So it's a very precarious situation in New England. I don't see it letting up any time soon because there aren't any necessarily big solutions coming. When we see Brayton Point and when we think about operational expansion, the kind of Brayton Point location as a Tier 2 for us, we've got some ideas for new generation and the like but that's a ways away. There just doesn't seem to be a lot of generation coming in.

The other problem they have obviously, is getting pipeline capacity to actually get gas in during the winter because obviously that's utilized for the home heating season. So I don't see the noise in New England letting up anytime soon. What was the other half of your question? Oh, California.

California, the main unknown for right now around Moss Landing continues to be the PG rate case and that process is ongoing and if it actually goes to a full hearing that will take us into the fourth quarter, stretch into December. Hopefully at some point in time we will have a settlement that we can negotiate with them. Right now they've been obviously very pre-occupied with bigger settlements that they're working on.

But that's kind of a real pivot point for us where that settlement goes off because -- or where the final rate case terms out -- but that ultimately drives a significant value of Moss Landing in one direction or the other.

And the thing that we continue to put forth to the Governor and to the California Water Resource Board is the Moss Landing provides such a good answer to the state of California to address their drought. You can see by ramping up Moss Landing just one or two, not even thinking about six and seven, you can save 2 billion gallons of water a year if you cycle down some of the combined cycle units that use [uni water] and we've got conversations done with the Agricultural Associations and trade groups out there and we're going to continue to push on it.

I don't know why California wouldn't jump on the opportunity to save 2 billion gallons of fresh water overnight. And it is something we're going to try to push that through the political machines and bureaucracy that exists in these places but it's an incredible opportunity for California to make a serious dent into some of water issues that they have out there.

And again, we are compliant with 316(b) out there. We would even accelerate some of the final negotiated agreements that we've reached for the Water Resource Board to extend the permit out there, so hopefully that get some traction out there and that would certainly drive some value with Moss Landing as well.

Stacey Nemeroff - *Bloomberg Intelligence - Analyst*

Stacey Nemeroff, Bloomberg Intelligence. I have a question about potential further development or plant acquisitions and three specific types of opportunities.

One, are you focused more exclusively on brownfield investments? Also you were speaking a lot about opportunity in the New England market and Eversource. They've indicated they are divesting their New Hampshire portfolio, so wondering how you view that?

And then also are you potentially open to increasing your clean energy exposure? Other competitors both IPPs and hyper generators are pursuing that or have indicated their openness to that.

Bob Flexon - *Dynegy Inc. - President & CEO*

So our focus first on expansion, which I provided some early looks and Hank will talk more about it, has been expanding existing generation capacity. Our alliance with GE has proven very beneficial and Marty gets certainly the lion's share of credit on that and what he's been able to work through with GE. He's uprate the speed to market, very low cost on average, $200, $250 a KW versus new capacity would which cost $1200, $1300 a KW. *Time to market is quite quick.*

So that's where our immediate focus is at. It's kind of our Tier 1 desire. In terms of renewables and I liked the word that you use, I think the way that we think about it is clean technology. We're looking at it a couple ways that on the renewable front, the only way that we would participate in something like that is if there happened to be within one of our markets some renewables maybe coming off contract, if for some reason when it came time to enter in some type of auction that makes more sense for us versus someone else.

And it is somewhat hard for me to see where that lies. I don't see any big jump into renewables. Maybe at one of our sites in Illinois that has excess land where you could do some type of PV application that would support Sheree's business in retail, maybe you could do that as part of growing the retail business because there it makes sense.

But jumping into a commodity renewable market or solar, that's not what we do. I think you see from our cost structure the things that Carolyn covered, we place a premium on being lean, agile, low-cost and not a lot of overhead. And when you decide to jump into a new business that you really have no core competency or no differential market advantage, you're going to build a layer of hidden costs. That's just not anything that I want to within Dynegy or the Board has an appetite to do because it's just not who we are. So we want to bring an advantage.

So when you think about clean technology, there are developing technologies out there that we are very interested in. On SO2 emissions and things of the like that are new technology that can lower your operating costs. So if we can find and develop with outsiders some new technologies around emission reduction -- we're getting into now the kind of the new buzzword is retro-commissioning, we're doing a retro-commissioning project at one of our plants where you look at energy leakage, look at ways to run the plant more efficiently, things like that.

Jeff Coyle talked about the arrangement that we just had with an outside firm that has new milling technology for coal ash, so we can market more of our coal ash, so things around clean technology I think is more of our sweet spot than just a general generic jumping into renewables and be a me-too player and see a lot of cash leakage that I don't have any desire to see at this point.

So we want to stay in our sweet spot, things that really help our portfolio.

And regarding Eversource, in general around M&A we try to understand what's in the marketplace and what makes sense for our portfolio (inaudible) and I don't necessarily have a view on those assets at this point in time only to say that we look at M&A in the context of our deployable balance sheet capacity and disposable or discretionary cash.

And at this point given our portfolio construct, particularly as it relates to New England and PJM where we are the largest generator in terms of combined cycle capacity relative to our market cap exposure to these two markets, I'm not in a real hurry to try to dilute that at all. I see that deploying a lot of our cash -- and again call it on average $1.5 billion or so over the next three years of deployable cash, that's one-third of our market cap, which could have significant value accretion for our shareholders.

So all of those things we have to take into consideration. I think it's our job to make sure that we evaluate all of the opportunities fully and come out and say what's the best risk-adjusted return profile for this Company and decide at that point. So fairly long-winded (inaudible).

With that we'll take a 15-minute break and then we will come back and do the second half.

(Break in progress).

PRESENTATION

Bob Flexon - *Dynegy Inc. - President & CEO*

All right, we are going to start off with the second half of the presentation. I would like to introduce Sheree Petrone who is our EVP of Retail.

Sheree Petrone - *Dynegy Inc. - EVP, Retail*

Thanks, everyone, good morning. So last year the first successful year for retail, I am happy to report. And this year we are continuing to execute the strategy that we have laid out for retail at the inception, which is to create value for our customers and our shareholders.

If you look at the -- so we have three priorities for retail. And first, we are a marketer of our generation fleet. So, we work to fulfill the hedge objectives set by the commercial team with forward sales that lock in value and reduce risk.

Second with the recent acquisition of Duke Energy retail, we continue to build a fully integrated operation that generates profit on a standalone basis.

And third, our marketing effort is focused on understanding customer priorities. This informs our decisions on the products and services we should offer and also Dynegy's long-term strategy overall as a generator located in the communities we serve.

Now for a little more detail on each of these, first starting with risk reduction. We have played a key role in supporting the commercial strategy to sell our MISO capacity through retail customer contracts. We have sold over 1,800 megawatts of capacity in Southern Illinois for planning year 2015-2016 which is about 28% of our available capacity. And this reduces the amount of capacity that alternatively we would have been a pricing through the MISO auction.

In conjunction, retail energy sales are forecast to exceed 11,000 gigawatt hours in 2015 which equates to 70% of the expected generation of IPH. As a generator we have a cost advantage when making offers to customers, first through the collateral efficiency that we create by linking retail load with generation. And our estimate is about $0.25 per megawatt hour for this benefit.

And in addition, internal hedging transactions eliminate the wholesale premiums that are paid by generators and load serving entities that transact independently in the market. This we estimate at a value of about $0.50 per megawatt hour. So, in total this results in about $20 million to $25 million in savings annually during the planning period.

Now for a little bit more about the markets. The retail business operates in both MISO and PJM and in Southern Illinois we sell power under the brand recognized by our communities, Homefield Energy. We serve just under 500,000 residential customers with fixed-price contracts and these are consumers that live in communities that procure power through municipal aggregation programs.

In addition we serve about 11,000 commercial customers that consume about half -- 55% of the power we sell. As you can see, we are the largest supplier in the MISO Southern Illinois with 29% of the market and we have an average customer renewal rate in excess of 60%.

And we feel that this is really a unique point in time as our competitors are reevaluating their interest in retail and they are either exiting, scaling back or consolidating, which gives us a great opportunity to grow.

In PJM we operate in Northern Illinois and Ohio and, as you can see, we are a relatively small player. We are now branding our expansion efforts there as Dynegy Energy Services. Currently we serve just over 400,000 residential customers mostly through muni agg, municipal aggregation. And in Ohio we do make some direct sales to mass-market customers through the use of digital campaigning.

Our C&I customers, numbering 19,000, consume about 70% of the power we sell. We see PJM as an opportunity for expansion now that we have a larger generation footprint in Illinois, Ohio and Pennsylvania.

So a little bit more about the growth on the next slide. Our growth strategy continues to focus on large volume transactions and they are the ones that are less costly to acquire and serve. So for C&I customers that means leveraging our expertise in the wholesale markets to provide energy offers that match a customer's risk profile.

For residential customers we work with a network of energy consultants to create cost competitive offers in response to large RFPs. And in addition, we are in the process of integrating our operations since we have added the Ohio business.

This we see as an opportunity to improve our operation, drive efficiencies, move to a standard platform and build common process across all of the markets. And these efficiencies will allow us to maintain a low cost operating model to serve our customers.

As far as growing market share and our goals, so in Southern Illinois we have a three-year goal of reaching a 40% market share as we have plenty of generation length available. And again, we have seen signs over the last 12 months of retraction from some of our competitors. And some of these are the smaller market participants or those that don't have sufficient generation to back load.

And as I mentioned earlier, retailers backed by generation have a cost advantage over the suppliers that are paying wholesale premiums in the market for load following energy products, especially post polar vortex.

In PJM we set an attainable three-year goal for sales in Illinois and Ohio. Now with a much larger generation fleet and Dynegy's new entrance and commitment to the retail market in Ohio, we are well-positioned to be much more competitive and win market share while other suppliers are reevaluating their retail business opportunity.

Now, this slide reflects a conservative growth rate for a Ohio since it is a new market for us and we are rolling out a new brand. But we do see opportunity for growth there.

So how does that impact the financials? With a focus simply on expansion in our existing markets we are confident that volume growth is achievable given the change in the competitive landscape and we can drive an increase in annual earnings.

And this projection is very reasonable in that it assumes prices will return to a more weather normal levels as our current contracts come up for renewal, and that sales growth will occur quickly -- more quickly in the large C&I segments where margins are typically lower or through large volume transactions like procurements for aggregate loads. We can be very competitive with the generation backed offers and it is really such an efficient way to hedge our long position.

Beyond our existing territories we are evaluating new markets for expansion, based on the number of criteria though to determine if there is really a fit. So first it's whether we have generation significant enough to actually need a retail channel and that the generation infrastructure is in place to manage risk associated with load following retail products.

In addition, there are other elements of the market that are important such as whether it is a pro competitive state and if utilities there facilitate supplier choice with programs like purchase of receivables. And we also need to be confident that our offers would be competitive when compared to other supplier offers. And also the residential market is certainly interesting to us where municipal aggregation opt out models are implemented.

So to summarize, the retail business continues to be an attractive channel to market for our generation. The changes we see in the competitive landscape make growth and an expansion in PJM well-timed. And finally, we are confident that the retail will contribute stable earnings throughout the planning horizon. So now the long awaited Hank with the commercial presentation.

Hank Jones - *Dynegy Inc. - Chief Commercial Officer*

Thank you, Sheree for that introduction. My name is Hank Jones; I am the Chief Commercial Officer for Dynegy. Thank you all for being here today.

So as Bob mentioned in his opening comments, the power industry is facing profound structural changes that will have a lasting impact on reserve margins and system dynamics for years to come. 48 gigawatts of dispatchable generation has been retired or is scheduled to retire in New England, PJM and MISO between 2010 and 2016.

In addition to the impact of this first wave of retirements, the system is experiencing a growing dependency on intermittent renewables and unreliable Demand response resources, all of which is expected to lead to firming capacity prices and higher and more volatile energy prices.

Poor asset performance during the first quarter of 2014 was a wake-up call for those responsible for system reliability. As an example during peak demand periods in January 2014, 20% of the generation capacity in PJM didn't perform.

Tight reserve margins coupled with poor reliability during high demand periods served as a catalyst for significant market design changes in New England and PJM. Performance incentives and capacity performance were put in place to drive reliability investment or the replacement of underperforming assets.

As a result of (technical difficulty) market design changes, older and less reliable assets are at a significant risk of retirement, with 10% to 15% of the capacity in PJM and 25% of the capacity in New England identified as at risk.

Given the challenges facing new builds and the speed with which older, less reliable assets will retire under CP and PI, new build will struggle to keep pace. For these reasons we expect tight reserve margins and the associated higher capacity and energy prices to persist for years to come.

Historical natural gas flows have changed dramatically over the past few years and have had a meaningful impact on power markets. A shortage of takeaway capacity from the Marcellus Shale has resulted in depressed natural gas prices in the region.

As low regional natural gas prices place downward pressure on power prices and contribute to the retirement decisions of uneconomic assets, they also result in expanding spark spreads for well-positioned CCGTs. As additional infrastructure is built to deliver this gas to other markets, natural gas prices are projected to rise in the region.

Natural gas demand in the United States is expected to rise by 7 to 8 Bcf per day over the next four to five years providing additional support for natural gas prices.

Dynegy has unrivaled access to inexpensive Marcellus gas at our combined cycle units in Ohio, Pennsylvania and New York which result in robust spark spreads and provides a significant competitive advantage in PJM and New York.

As an example, this week we paid $1.30 to $1.70 per MMBtu for gas delivered to our CCGTs in Ohio and Pennsylvania while selling on-peak power at $40 to $55 per megawatt hour. Our southern New England fleet has firm natural gas transportation agreements in place for 25% of their peak demand and will be some of the first assets in New England to benefit from pending pipeline capacity expansions.

While low natural gas prices have put pressure on coal-fired generation economics, we are a low cost producer in MISO and PJM and are well-positioned to weather the impact of low regional natural gas prices.

Through aggressive rail contract negotiations, coal sourcing, coal blending and the implementation of refined coal at our facilities in PJM and MISO, we have achieved a low delivered cost of coal providing us with a $6 per megawatt hour fuel cost advantage in our PJM Ohio fleet versus eastern coals and a fuel cost advantage of up to $3 per megawatt hour versus our peers in MISO.

In turning to slide 66, as you can see from the bar chart on the left, a disproportionately large amount of retirements in PJM and MISO occur in 2015 with more to come next spring as a result of mass compliance deadlines. These retirements will have removed 15% of the capacity in ISO-New England, PJM and MISO since 2010. Retirements are occurring not just in these three markets, but also in SPP and SERC for their tightening regional supply balances.

The system's reliance on non-dispatchable capacity is growing at the same time that dispatchable assets are retiring. Wind and solar generation will comprise between 6% and 10% of the generation mix in New England, PJM and MISO by 2020. Random swings in output and the non-dispatchable nature of wind and solar resources make them a poor substitute for dependable coal, gas-fired and nuclear generation.

There is no guarantee that intermittent resources will produce during peak demand events as the chart on the right illustrates. The vertical access on the left and the blue line depict the peak load in PJM for the period from January 6 through January 9 of 2014. The vertical axis on the right and the red line represent wind energy output in PJM during the same period.

As you can see, when temperatures dropped and demand was peaking wind output dropped dramatically. Dispatchable resources were called upon to satisfy system reliability. This phenomenon will become more apparent and more impactful on energy prices as the system tightens up in a post MATS environment.

Since 2010 Demand response as a supply resource has grown substantially. DR and PJM has proven to be unreliable when called upon. 70% of the Demand response resources provided no reduction in load during PJM Demand response events in 2014.

These resources receive capacity payments in spite of their failure to perform during shortage events. Their inclusion in the capacity auction effectively depressed capacity market clearing prices by 25% to 30% over the past several years. Due to market design changes DR will play a limited role as a supply resource through auction.

Moving to slide 69. In New England, in addition to the tight reserve margins projected in planning year 2018-2019, an additional 5 gigawatts of primarily oil fired steam units are at risk due to their inability to perform to PI standards. New builds are slow to arrive in New England due to challenging permitting processes and the need for infrastructure build out.

We expect capacity prices in New England to remain firm and we have submitted transmission service requests for an incremental 100 megawatts of low-cost up rates at our existing facilities that we expect to qualify as new capacity and be eligible for the seven-year lock to capitalize on tight market conditions in FCA 10.

Imports alone will not solve new England's reserve market problem. Northern Pass is tentatively targeted for delivery in 2019 but still faces further state regulatory approval before moving ahead. ISO-New England has proposed several capacity zones to stimulate investment where additional generation resources are required and to discourage investment where it is not required.

The addition of Northern Pass in the proposed Northern Zone would likely cause the zone to separate and clear at a low price. This zonal construct would trap Northern Pass and Casco Bay but would protect Dynegy's assets in southern New England.

The full effect of match retirements is reflected in our projection of reserve margin shortfalls in over -- of over 3 gigawatts in MISO's North and Central zones for planning your 2016-2017 which is next year's auction.

Given the vertical demand curve employed by MISO, a capacity shortfall in the system may result in a system-wide clearing price at CONE which is estimated to be at $250 per megawatt day. We do not envision a quick fix to MISO's reserve margin shortfall and it is unrealistic to expect enough new build to enter the system to solve the shortfall until planning year 2018-2019 at the earliest.

As the MISO capacity market tightens up we have significant volume to place in the market. We continue to pursue transmission paths to export MISO capacity to PTM for future planning years. We are exporting approximately 850 megawatts to PJM in planning your 2016-2017 and expect to complete a transmission path for an additional 240 megawatts of exports from Joppa to PJM in planning year 2017-2018.

All of these MISO export volumes will qualify for capacity performance from PJM. Although the next significant retail sales opportunities are not expected until this fall, we have sold incremental retail volume in Zone 4 over the past few weeks that incorporates updated market views on capacity pricing.

We are also in active discussions with munis, co-ops and utilities throughout MISO regarding additional long-term structured transactions. We recently closed an eight-year transaction at a weighted average capacity sales price of $3.82 per KW month or approximately $125 per megawatt day. This is evidence of a promising trend with load serving entities in MISO continuing to secure capacity for the long-term.

A significant portion of the first wave of PJM retirements is located in Ohio, West Virginia and Western Pennsylvania and will precede the new build response. 8 gigawatts of deactivations occurred in PJM since May 1 of this year alone. New builds are more heavily weighted towards the east and will come into service over the next two to four years.

The evolving regional balances are constructive for Dynegy in that over 80% of our PJM capacity is located in the West. We see tightening supply dynamics resulting from the first wave of retirements increasing the around-the-clock energy price in the AD Hub by $2 to $3 per megawatt hour.

We expect the first wave of generation retirements to raise energy prices not only in PJM but also in New England and MISO as well. As the full impact of asset retirements take hole, price scarcity premiums may be substantial and will become evident during high demand periods and system shortage events possibly as early as this summer, but certainly by the summer of 2016.

Our hedging strategy is driven by a balance between our market view and appropriate risk management practices to secure cash flow targets. 2016 hedge levels across the coal segment and IPH are at 30% to 40% and protect a portion of our coal fleet from the potential impact of lower natural gas prices in the region.

Our coal segment now includes not only our DMG MISO assets, but also the recently acquired coal assets in PJM and New England. The gas segment is substantially less hedged during this period to allow for appreciation in spark spreads as power markets tighten and gas prices remain under pressure.

Our forward hedging percentages will increase as the prompt year approaches with IPH hedging activity driven by the retail sales cycle and the coal and gas segments hedged opportunistically. Our position in 2017 is largely open and reflects our bias that the structural changes we have discussed will lead to higher energy prices and increased volatility that is yet to be recognized in forward markets.

As you can see from the bar charts depicting the various components of the supply stack in each of our three primary markets, intermittent resources and DR make up a substantial portion of the reserve margin and their share of the asset base is growing. In 2020 without DR, PJM, MISO and New England are actually short versus reserve margin targets.

In the CP and PI world not all megawatts are equal. A generator or supply resource collecting capacity payments will be held accountable for performance. The new market design at PJM and New England will likely drive a second wave of retirements as non-reliable assets either can't survive the penalty regime or price themselves out of the market during the auction.

The chart on the left illustrates the 2014 forced outage rate by plant type in PJM. Each diamond on the chart represents a generating unit; the red circle represents the capacity weighted average forced outage rate for each plant type. Combustion turbines and steam units account for 60% of the installed capacity in PJM and experienced a weighted average forced outage rate of 18% and 15% respectively in 2014.

As you can see, there are a number of combustion turbines and steam units with substantially worse forced outage rates than the class average. Without investment to increase the reliability of these assets a significant number of these at risk units will not survive in a CP environment because they will no longer be able to collect a risk-free capacity payment from PJM.

Many of these retirement decisions will be made prior to new build filling the gap which may prolong a period of tight reserve margins across the system. As reserve margins tighten zonal balances within PJM become more critical. We have identified 10% to 15% of the capacity in the ComEd and AEP zones as at risk due to age and performance characteristics.

Without reliability investments or new build these zones may separate from the RTO in upcoming auctions. New England is faced with a similar dynamic and an additional 5 gigawatts are at risk for retirement with the majority of these assets located in southern New England.

This projected second wave of retirements and asset replacements will be driven by an onerous penalty structure for nonperformance. Penalties during shortage events in PJM are estimated to be $3,900 per megawatt hour and rising from $2,000 to $5,000 over time in New England.

At $3,900 per megawatt hour, with 16 hours of nonperformance in PJM during shortage events, the penalty payment is equivalent to $170 per megawatt day, which is close to the market consensus estimates for the CP clearing price in planning year 2018-2019. This means that the entire CP payment can be lost in 16 hours of nonperformance during shortage events. In this type of environment the stakes are high and reliability, critical mass and a diverse portfolio are critical to success.

Dynegy owns approximately 11 gigawatts of installed capacity in PJM and will import another 850 to 1,100 megawatts from MISO via firm transmission paths. As the largest merchant owner of CCGTs in PJM, Dynegy is well positioned to benefit in a capacity performance market with a diverse and reliable fleet consisting of over 60 generating units.

Dynegy's fleet performance is on par with the PJM average in 2014. Excluding Zimmer, which was previously limited to interruptible natural gas supply for start-up fuel, the EFORd of Dynegy's coal units in PJM in 2014 was 13% versus the system average of 12% and 1% at our CCGTs versus the system average of 4%.

Reliability initiatives such as winterizing exposed equipment, commissioning dual fuel start-up capability at Zimmer, developing alternative natural gas pipeline supplies, and pursuing firm gas transportation and delivery options are underway to enhance our reliability and to position the fleet for the capacity performance market.

Citing, permitting and financing challenges do not allow for a quick new build response. New entry faces significant hurdles and response time is lagging the first wave of retirements. We expect new build to lag the timing of the second wave of retirements as well.

As an example of this lag time, in spite of the opportunity to lock in $9.55 per KW month for seven years, only 1,000 megawatts of new capacity cleared the planning year 2018-2019 New England capacity auction. Historically PJM has only added 2 to 4 gigawatts of new capacity each year and only 20% of announced new build actually ever gets built. It will be difficult to measurably accelerate this rate going forward.

While spark spreads in PJM are at historical highs it is difficult to lock in these rates beyond 2016. Additionally, the hefty collateral amounts required of developers to guarantee potential CP penalties and the fact that CP payments are at risk further increases the cost of development projects and serves as another hurdle for new entry.

Due to market design issues, the only new entry expected in MISO is within regulated utilities outside of Zone 4 and there are only 2 gigawatts of new build with interconnect agreements in place targeted for completion by 2019.

We are implementing expansions and up-rates to our existing facilities with economics and speed to market that are far superior to new build opportunities. We've identified over 645 megawatts of up-rates and expansions at our existing sites most of which come in service by the fall of 2016.

These up-rates range in cost from $5 per KW to activate combustion turbines in Southern Illinois to $200 to $400 per KW for up-rates in the Northeast. This compares to recently quoted new build CCGT cost of $1,100 to $1,200 per KW in Eastern PJM.

260 megawatts of our up-rates are targeted in PJM with 210 megawatts expected to be in service by the fall of 2016. These up-rates will increase the efficiency and the output of the plants and will qualify for capacity performance. We have submitted transmission service requests for 100 megawatts of up-rates at our facilities in New England.

We are confident that the 70 megawatts of up-rates at Lakewood and Milford will not require significant transmission upgrades, will qualify as new capacity in FCA 10 and will be eligible for the seven-year lockup for new capacity.

The expansion opportunity at Independence is expected to bring an additional 50 megawatts of energy producing capability to the plant and will allow us to capitalize further on the strong spark spreads we regularly achieve at Independence.

At Joppa we are in the process of returning 235 megawatts of gas fired peakers to service at a cost of approximately $5 per KW. These megawatts can be delivered to MISO, TBA or KU via our EEI transmission system.

Additionally, we purchased Burke's Hollow as a potential development site adjacent to our Ontelaunee plant and will explore the possibility of taking advantage of the synergies of co-locating a new CCGT next to Ontelaunee.

Summary, Dynegy is well-positioned with critical mass and a reliable and diverse generation fleet in markets where tight reserve margins are expected to persist and quality of assets matters. We have a substantially open forward hedge position which reflects our view that the structural changes facing the industry will result in meaningful increases in power prices.

Inexpensive Marcellus gas has changed power market dynamics and we are well positioned for the opportunities and the challenges it creates. We have unrivaled access to Marcellus gas for a large portion of our fleet and we are a low cost producer of coal-fired energy in PJM and MISO.

While there are substantial barriers to new build, we are capitalizing on changing market conditions by adding up to 645 megawatts of expansions and up-rates to our existing fleet at an average cost of $200 per KW in a fraction of the time it takes to bring on a greenfield project.

In summary, there are profound structural changes occurring across the power market and their impact is expected to persist in the form of tightening reserve margins and increased capacity and energy prices for years to come. Dynegy is extremely well-positioned to benefit from these market conditions now and into the next decade.

Thank you, and I will turn it over to Clint for our financial overview.

Clint Freeland - *Dynegy Inc. - CFO*

Thank you, Hank, and good morning, everybody. My name is Clint Freeland, I am the Chief Financial Officer at Dynegy. Over the past several years the financial strategy of the Company has been focused on driving efficiency in the cost structure and the balance sheet of Dynegy, in building and diversifying our sources of liquidity and generally positioning the Company to execute and growth initiatives should they arise.

Over that time frame we have made significant progress really on all fronts and today have a balance sheet that is strong and improving, a liquidity profile that is sufficient for all current and future needs, a cost structure that is efficient and stable over time. And a balanced portfolio of assets that generate significant gross margin across multiple markets.

THOMSON REUTERS

Now given many of the market dynamics that you just heard about, we expect Dynegy to generate significant EBITDA and free cash flow over the next several years. And as a result, to have a significant amount of excess capital to allocate in the years to come.

Now while the Company has changed quite a bit over the past couple of years our approach to capital allocation has not. As we have said on a number of occasions, the first call on capital at Dynegy is for our plants to ensure that the appropriate amount of investment is made in safety, reliability and environmental compliance. We also prioritize our balance sheet and liquidity to be sure that the financial foundations of the Company remain strong.

Now from a balance sheet management standpoint, our longer-term goal or medium-term goal is to migrate to BB credit metrics over time and we think that we are well-positioned to do that. And as we move forward we may look to refine our leverage profile from time to time, but in general we are happy with where our balance sheet is and with where our liquidity is.

And what that means is that going forward the vast majority of the free cash flow generated by the Company should be available for intrinsic and extrinsic investments or returning to capital to shareholders. And as we look to make those decisions we intend to use share buybacks, or the economics associated with share buybacks, as the benchmark against which other uses or other investment opportunities are measured.

Now as you can see our focus on capital efficiency and allocation has resulted in a virtual doubling of Dynegy's return on invested capital over the past couple years from 5.5% in 2013 to roughly 10.8% this year while at the same time driving down the cost of capital by roughly 250 basis points.

The main contributors to the improvement in ROIC are primarily our PRIDE program as well as the two most recent acquisitions that, when compared against the amount of capital deployed, generate an ROIC of roughly 16%.

Now as I mentioned earlier, our medium-term goal is to migrate to BB credit metrics over time, and again I think we are well-positioned to do that. As I will get into in more detail in a moment, we expect to generate a significant amount of cash over the next several years sufficient to drive the Company's net debt to adjusted EBITDA ratio down from 4.9 times today to somewhere in the mid 3 to mid 4 range.

Now, while I wouldn't expect to use a lot of our cash to delever the balance sheet to those levels, it does demonstrate the Company's ability to manage its balance sheet to its target metrics.

Looking at the FFO to debt trajectory over the next several years, we may get to BB credit metrics over time naturally through increased earnings. That is something that we are going to need to keep our eye on, but be sure that we are always moving in the right direction from a balance sheet management standpoint.

Now that was the DI balance sheet, but we also keep a close eye on the IPH balance sheet. And from everything that we have seen so far, the financial outlook for IPH has materially improved.

There are a number of reasons for that, including the forward sale of capacity into MISO and PJM, positive contributions from our retail business, and a significant improvement in the cost structure of the subsidiary driven mainly by original transaction synergies, our PRIDE program, our new rail agreements as well as lower corporate cost allocations.

Now many of these items are in place today but will benefit IPH in coming years. So one of the things that we have done to try to capture this and to demonstrate this is to put together a forecast for IPH that only looks at those items that are in place today. And that, together with the forward curve, is the scenario that we call our current status case.

And as you can see under that very conservative case, the net debt to EBITDA for IPH over the next several years falls from about 8.8 times today to roughly 5.5 times on average over that three-year window. And from an FFO to debt standpoint, the FFO to debt improves from roughly 2.2% today to roughly 9.5% on average.

Now to the extent that our retail business is able to renew its book of business and roll that forward, to the extent that we are able to sell more capacity out of IPH, or to the extent that actual power prices materialize above the current forwards, all of those could be meaningfully accretive to the financial profile of IPH.

Now 2018 and 2019 are critical years for IPH with a $300 million debt refinancing as well as a meaningful investment in backend controls at Newton. So we are keeping a very close eye on IPH's ability to meet these obligations, but so far, based on what we see today, we are encouraged.

Now historically we have spoken about needing to have roughly $600 million to $800 million in cash liquidity to run the business. And I thought it would be helpful to kind of break that down into kind of the largest components.

From a working capital standpoint the combined Company -- the combined Company's working capital needs are relatively steady throughout the year, but can spike during the winter as fuel and power prices increase and become very volatile. So to demonstrate this we put together a pro forma rolling four quarter look for the combined Company.

And as you can see, just this past winter as prices spiked working capital spiked for the combined Company. From peak to trough that is roughly $150 million to $200 million. And again, this is something that we need to prepare for and manage to.

Now historically one of the most significant uses of the Company's liquidity has been providing collateral to our natural gas suppliers. And with the addition of so many natural gas plants in the most recent transactions that need is only increasing.

So to estimate what the collateral need for the combined Company going forward is, we put together a simulation for the combined fleet that mimic the polar vortex to see how much collateral would we need to post in that situation. And the result of that analysis showed that we needed roughly $650 million in collateral to post to our natural gas suppliers.

Now we would meet that in several different ways. First, we would max out the amount of first lien capacity that we have available for natural gas purchases. Second, we would max out the amount of letters of credit that we would issue to our suppliers. And looking through our various supply agreements that comes out to about $250 million. And then we would need to post cash for the balance which would be roughly $200 million.

Now posting cash collateral to our natural gas suppliers isn't the only place where we post cash. We also post collateral against some of our hedge positions on various exchanges that we use to manage our seasonal hedge position. Historically that amount for the legacy DI fleet was roughly $50 million to $100 million and we estimate that on a go-forward basis for the combined Company that is roughly $100 million to $150 million.

And then finally, one of the areas that I don't think it gets a lot of attention is the lumpiness of our interest expense. Looking at our $5.1 billion acquisition financing, interest expense payments are due every May 1 and November 1 of each year. And on our legacy DI debt interest payments are due every June 1 and December 1 of each year.

And what that means is that every year there are two 30-day windows during shoulder periods when $215 million in cash needs to go out of the Company to service our debt.

So in total this gives you a sense of the building blocks of how we get to the $600 million to $800 million in cash. Now I would say that over time I think there may be opportunities to bring this down to manage this to a lower level and we certainly will do that.

But even with all that said, given our current liquidity position of roughly $1.5 billion, $600 million of which is in cash, I think our current liquidity position is sufficient for all of our current and future needs.

Now for Dynegy there are four main areas of cash cost: G&A, O&M, CapEx and interest expense. And as you can see from the slide, all of these are roughly stable over time. And what that means is that as the Company generates gross margin, and increasing levels of gross margin, that that should fall directly to EBITDA free cash flow and capital available for allocation.

Now as a result of the most recent transactions Dynegy's gross margin is much more diversified and I would argue higher quality with roughly one-third of our gross margin going forward coming from market capacity revenues versus only 12% just last year. And roughly two-thirds of our gross margin going forward is coming from a diversified energy margin led by our PJM fleet.

Now there are a number of factors that influence our gross margin, one of the most significant of which is the price of natural gas. Now in the past we have provided a sensitivity analysis showing that for every $1 change in the delivered price of natural gas that our EBITDA sensitivity was roughly $360 million.

Now that was based on an analysis that looked at how forward power prices and forward spark spreads responded to changes in the price of natural gas in the forward markets. And that was specific to the timeframe 2011 to 2014. We have since refreshed that analysis and rolled that timeframe forward to 2013 to midyear 2015.

And what we have seen is that some of the correlations between the gas and power in that new timeframe have been weakening. And as a result our sensitivity to a $1 change in the delivered price of natural gas has fallen to roughly $290 million.

Now in looking even further into the new timeframe between 2013 and 2015 there is a very important dynamic that is taking place that we are seeing that investors need to keep their eye on. When you look at the sensitivity from year to year during that updated timeframe, the sensitivity of our MISO fleet really doesn't change. When you look at our New England fleet the sensitivity really doesn't change.

But within that timeframe what we are seeing is a meaningful change in the sensitivity of our PJM fleet -- we tried to call that out at the bottom left-hand part of the slide here. Just several years ago a $1 change in the delivered price of natural gas for the PJM fleet would have translated into roughly $140 million to $160 million change in adjusted EBITDA, where in 2015, looking at 2016 forward, that sensitivity is only $10 million. So obviously a significant change.

Now this is something worth keeping your eye on. Because to the extent that this dynamic continues, and it certainly can change and go the other way, but to the extent that this continues it will bring down the overall sensitivity of the Company in natural gas over time as we roll the analysis forward.

So now, while these are all of the relationships that are implied by the forward markets over the long-term, there are factors that can cause these relationships to break down in the short-term, such as weather, leading to results that are different than what the sensitivity would suggest. And that is exactly what we have seen over the last 9 to 12 months.

We originally initiated our 2015 guidance in August of 2014 and since that time the price of natural gas is come down significantly. But it hasn't had a meaningful impact on our forecasted results for this year. And the reason why is that market heat rates this year have been significantly higher than what has been implied in the forward markets historically.

So when using our sensitivities it is really important to really use them in two steps. First is to look at, in response to changes in gas, what our sensitivities would imply because that is based on history and what has been implied in the forward markets over time.

But the second step is important as well -- look at what the current market is doing to see if those historic relationships are holding. If they are not an adjustment needs to be made to take into account that there is a difference between how historic forward markets are moving versus today's current markets.

Now as the Company generates EBITDA and free cash flow on a go-forward basis, one of the largest assets of the Company will come into play, its $3.5 billion net operating loss carry forward.

Based on current calculations, to the extent that the consolidated adjusted EBITDA at Dynegy over the next five years is on average over $1.1 billion we will be a positive taxable income generator, that we would then be able to use our NOL to shield and protect us from being a significant federal income tax payer.

Now as we move forward taking into account all of the dynamics that you have heard this morning, we have updated our forecast for the 2016 to 2018 timeframe to provide investors with a better sense of the earnings power of the combined Company.

We have done that by really running two separate forecasts, the first is our base case which uses market power prices and market spark spreads, as well as certain assumptions around unsold capacity and the PJM transitional auctions. And the second is our incremental case which uses our internal view of power prices and spark spreads from 2016 to 2018.

Now based on these two scenarios we would expect for the Company to generate in total between 2016 and 2018 consolidated adjusted EBITDA of $3.9 billion to $4.9 billion.

So as you can see, we believe there is meaningful earnings growth potential with the assets that we already have and with the stable cost structure that we have in place for that to translate into significant free cash flow and capital available for allocation.

Now of the $3.9 billion to $4.9 billion in aggregate consolidated adjusted EBITDA, $600 million to $700 million of that is at IPH. And IPH will use that to pay its own interest expense, it is environmental and maintenance CapEx going forward.

Now given the ring fence nature of that subsidiary, any free cash flow generated during the period will remain at IPH and not be available at DI for allocation. Of the remaining EBITDA generated by the coal and gas segments roughly $2.2 billion will be needed to pay our interest expense as well as fund our maintenance and environmental CapEx and investments leaving roughly $1.1 billion to $2 billion in excess capital available for allocation.

Now of this amount about $75 million will be needed to make mandatory principal repayments on our term loan, as well as pay dividends on our mandatory preferred stock. And we're also evaluating, as you've heard this morning, incremental investments in both reliability and up-rates.

But those will need to be economically justified as part of our capital allocation program. But even with those investments being made, we still expect a significant amount of capital to be available for allocation over the next several years.

So in summary, the financial foundation of the Company is strong and with the balance sheet, liquidity and cost structure of the Company where it needs to be, we see Dynegy as being well-positioned to be a significant generator and allocator of capital in the future. And with that I will turn it back over to Bob.

Bob Flexon - *Dynegy Inc. - President & CEO*

Thank you, Clint. Today -- we have covered a lot of ground today and I have tried to capture the themes on a conclusion slide -- I won't go through them all because I know it is quite busy. But I wanted to put generally the general takeaways that I think everybody should have from today's session.

I would also like to add that our investment thesis that I outlined at the very beginning remains constant, it is the same investor thesis that we had when we first had our investor meeting back in January of 2013. And that is the retirement of base load generation that is happening across the market, that is happening that is driven by economics along with the continuing flow of state and federal regulations that continue to impact generation assets.

I think the new change that we have now going forward is how capacity performance or performance incentives is again going to change the mix of generation assets with an obligation for quality megawatts and the implications of not meeting your delivery requirements during a declared shortage event.

I would say now today that Dynegy's portfolio as reconstructed over the past couple of years is best positioned in these markets to meet these obligations. And that combined with the cash flow generation profile that we see for these assets.

I would say today that our Dynegy is positioned better than it has ever been in the past, and that combined with our disciplined capital allocation approach to the business I would say the outlook for the Company, for its stakeholders and for its shareholders has never been brighter.

I would also like to add before we go to the Q&A that part of the objective that we have coming to a meeting like this is for our shareholders to see the full management team. And the team that has worked hard at pulling this information altogether.

We also have three members of our Board of Directors here, we have Paul Barbas, Hilary Ackerman and Jeff Stein -- was here. Oh there he is, he's hiding. So the takeaway that I want you to have from meeting the management team and several of the board members is that we have got a deep bench, we've got a lot of talent in the Company throughout at all levels.

The teamwork is excellent and it's those combination of factors that gives us the agility in the market to do things like announcing two acquisitions on the same day, integrating them into the portfolio during the same time period, having it fully integrated within two months, capturing the synergies that we said we would capture.

It really is just a testament to the employees that we have and it starts Board of Directors all the way through the organization, we really have built a great Company with a lot of great talented individuals and that is certainly important for us to demonstrate to our shareholders as well. And that is part of our objective today as well as trying to be as transparent as we possibly can on the business for all of you.

So at this point though I would like to open up for the final Q&A session. I guess we have about 30 minutes or so, Andy, to go through that. I should also add that this is Andy's last Investor Relations activity. He is switching jobs with Rodney McMahan who is over there very stressed (laughter). Andy is a lot happier than Rodney.

QUESTIONS AND ANSWERS

Felix Carmen - *Visium Asset Management - Analyst*

Felix Carmen, Visium Asset Management. Can you share with us some of the assumptions that you are including in the $1.3 billion run rate, the adjusted EBITDA? Maybe talk about what you are assuming for the incremental auctions in the 2018-2019 planning year.

Bob Flexon - *Dynegy Inc. - President & CEO*

Okay, and so the question is what are some of the assumptions built into the forecasted EBITDA over the timeframe and what are the assumptions built around the transitional and the capacity performance options within PJM. Clint, do you want to --?

Clint Freeland - *Dynegy Inc. - CFO*

Yes, I will start off with and (inaudible) any additional (inaudible). Yes, so for the base case, as I mentioned, we use market curves for power prices and spark spreads as of mid-May. For the unsold capacity we made certain assumptions around the transitional auctions, kind of working with the commercial team.

We tried to be relatively conservative on the outcome of those auctions. Obviously we don't want to be too specific given that there is an auction coming up in (inaudible). But I think we were -- there are a wide range of outcomes that are possible and we try to be kind of on the conservative end of our expectations for the transitional auctions.

For the MISO capacity, in general I would say that the prices are expected in that base case are generally consistent with the most recent auction. However, we do make certain assumptions on how much of that capacity actually clears. Again, I don't know if we can be more specific than that.

We do assume that the retail book does roll forward at historic levels and then it is just a matter of -- then we also already have volume sold into MISO, volume sold into PJM. And just how much of that amount that is left is sold at prices that roughly are equal to more recent [clearing in] MISO.

Bob Flexon - *Dynegy Inc. - President & CEO*

And then maybe just one thing I would add that Sheree is experiencing in her business, our win rate on the Homefield Energy side has declined a bit since what it was in the past and that is because we have a firm view on the value of our capacity in MISO.

And as part of our retail bidding processes, we take that view on value, which is similar to recent auction clears, that that is the value of the capacity in MISO and that is built into the forecast as well.

Unidentified Audience Member

And just one follow-up question maybe to kind of help gauge our expectation. Do you have maybe perhaps a sensitivity for maybe every $10 deviation from the current PJM [clearance] price of 120? What would that translate into EBITDA?

Hank Jones - *Dynegy Inc. - Chief Commercial Officer*

I think -- and check me on this, but I think the sensitivity is that for every -- assuming that the entire fleet clears that for every $10 change it is $40 million in EBITDA?

Clint Freeland - *Dynegy Inc. - CFO*

Yes, and a key assumption there is that if every megawatt were to clear a $10 uplift is (multiple speakers).

Unidentified Audience Member

All right, so a quick question, I will try to be clear. So with regards to the IPH portfolio, is that included -- I know in the SCF breakdown -- is that included in the $3.9 billion to $4.9 billion, the IPH?

Clint Freeland - *Dynegy Inc. - CFO*

Yes.

Unidentified Audience Member

It is indeed, okay, great. And then secondly more strategically, you've obviously got a couple deals off the ground. And I don't mean to be too early about this, but how are you thinking strategically about deals going forward? And specifically in that regard, there is sort of a hole when it comes to Texas and your positioning around the country. How do you think about that?

Bob Flexon - *Dynegy Inc. - President & CEO*

I think our view on M&A processes as we go forward is much like we have (inaudible) in the past, and that is to make sure we are really aware of what is happening in the market there. Are portfolios coming to market? How they fit with us we would evaluate.

We don't necessarily think we have any particular market restrictions. It is more around what is the best investment opportunity for the Company when you look at all of the alternatives. What is different today versus a couple of years ago is we have critical scale, we have critical mass in the markets where we want to be.

Certainly I am glad we didn't invest in ERCOT a couple of years ago. We went -- obviously PJM and ISO-New England. ERCOT has gotten certainly over the past few years a lot less bullish than what it previously thought it was going to be. But it is up to us continually to look, evaluate, and determine what is the best use of our capital.

The urgency around mitigating the risk that we have with just one or two assets that we're really driving the cash flow is behind us. The risk of carrying a subscale portfolio is behind us. And I think you see the value of leverage that -- leveraging the scale that we have. So it is really just opportunistic and what is the best use of our capital.

And there aren't as many opportunities as there were in the past. Again, we continue to evaluate and see -- I don't want to get specific to any Company or any particular asset. But I wouldn't close the door on anything. Again, we just have to go through the evaluation and what is the best thing to do for the Company, for the shareholders, and what's the best risk adjusted return that we can pursue.

Unidentified Audience Member

Great. And then perhaps another strategic question. Obviously a lot of legislative efforts Ohio, Illinois -- focusing on Illinois first. Can you comment a little bit about your expectations on MISO capacity as it relates to what comes out of that process?

Specifically I suppose Clinton is a big wildcard as it would relate to capacity price expectations. How does that drive your thinking and then what are your expectations at present in Illinois given where we are in that?

Bob Flexon - *Dynegy Inc. - President & CEO*

So the question is around MISO capacity. We have gone through the auction, review is under way and the like. So what is our expectation for MISO capacity going forward? Certainly there is a number of dynamics at work. There is just the base fundamental of just how much capacity is within MISO wide system.

Our theory around MISO has always been more around the entire MISO, classic MISO footprint than specifically to Zone 4. We just have continually viewed that as we approached 2015, 2016, 2017 and 2018 that there could be a capacity shortfall due to retirements. And within MISO a lot of the one year MATS extensions were granted.

And MISO has another wave of retirements under MATS that will (inaudible) the next or have an impact on the next capacity auction next March. So there is further tightening there. And whether or not there would be enough resources, to be determined. As we talked about earlier this morning, they have done some cosmetic things to change that around reserve margins, forecasted demand. But the fundamental issue in MISO was nothing being built, stuff is being retired.

So I expect continuing tightness. Whether it gets to an administrative cap over the next year or two is to be seen, it is very, very close to that. Right now we do have the [attention] that Zone 4 is not designed properly.

As I mentioned earlier, John Bear at MISO has talked to Illinois about some specific potential redesign of Zone 4 to make it have a lot of characteristics that we are looking for, a three-year forward look, a sloping demand curve and the like -- make that specific to Zone 4 to get a better construct in place.

How long it takes to get that into place will take some time, but we also have Illinois legislature certainly very much focused on this. What happens to Clinton is the question mark (inaudible). As Clinton retired do they need it for liability, how does that impact the auction process or again some open questions. So, to be seen, but I think the trend is just tighter and we are getting closer and closer to not having enough reserve requirements within MISO.

Unidentified Audience Member

And then last little detail, mark-to-market on the portfolio versus the guidance? The date sent was May 13 versus today. Any sense on what that delta would be, maybe that is a Clint question.

Clint Freeland - *Dynegy Inc. - CFO*

Yes and I don't have specific numbers, but certainly you have seen the curb curve weaken since the middle of May. But again, I think a lot of it has to do with kind of weather expectations and certainly that can turn. So we tried not to kind of constantly mark that to market, but I think certainly since that date we have seen some (inaudible).

Bob Flexon - *Dynegy Inc. - President & CEO*

We generate 120 million megawatt hours a year, right, so, moves a dollar and that dollar -- that could happen tomorrow. So this does have some volatility to it (inaudible) turning around a little bit.

Unidentified Audience Member

I wanted to ask you about slide 77. The reserve margins there for Western PJM look a little lower than I recall PJM's forecast. Is that because of some local transmission constraints or is there some other calculation that you are putting into it? I am sorry if I am a little slow there, but it wasn't completely clear to me on that. And if it is some adjustments that you guys had made --.

Unidentified Company Representative

(Inaudible - microphone inaccessible).

Bob Flexon - *Dynegy Inc. - President & CEO*

So was that 70?

Unidentified Company Representative

(Inaudible - microphone inaccessible).

Unidentified Audience Member

That's it, that's the one. So when I look at that, the Western PJM was 10%. Now just wondering is that because of some local transmission constraint or were there some adjustments that you guys are making? And if you were to apply that adjustment, if that is what it is, to 2015-2016 what would that be just so that we have some idea about what is going on there? That is the first question.

And then the second question I have is associated with what you guys expect in terms of new entrants. You mentioned a few things, there are some new barriers to entry, etc. But what are your expectations for the next BRA, roughly speaking, in August or whatever for new entrants to come in given the new capacity performance stuff that we have here going on? If you guys could opine on that, that would be great.

Bob Flexon - *Dynegy Inc. - President & CEO*

Yes, so, the first question that I think you asked was around Western PJM, what is the assumption, what is the assumption that's being built in there in terms of the 10% capacity at risk with that?

Unidentified Audience Member

So the reserve margin looks like it is starting at 10% for 2015-2016 -- 2016-2017, right? And that is a little bit lower than what I generally think of what PJM has got forecasted, right. So maybe you are taking out the (inaudible), I am not sure what is going on. But if you -- if it is an adjustment as opposed to maybe some transmission constraint what would the impact -- what would be (inaudible) now, in other words what is the reserve margin?

Bob Flexon - *Dynegy Inc. - President & CEO*

Sure, so the starting point for 2016-2017 of 10% at Western PJM, what is behind that (inaudible)?

Hank Jones - *Dynegy Inc. - Chief Commercial Officer*

So, this is our internal analysis based on a potentially different geography than specific PJM zones. And I can't speak to how this would reflect in a 2015-2016 reserve margin case. The point of the graph is to suggest that there is substantial capacity at risk in the AEP zone and the ComEd zone as a result of performance characteristics and age of the units. And if new build did not occur over time there is a substantial shortfall.

So I guess to your second question about our expectations on new build, there clearly are limitations in terms of the speed with which new capacity comes into the system. We are not -- it is logical that new builds should come into the system. That is how -- that is why this market is set up this way is to inspire investment. And we do expect new build to come, we just don't think it happens in one big slug.

It consistently (technical difficulty) 2 to 4 gigawatts a year across the whole system and that's a huge percentage of the volume that's -- or of the projects that are listed don't ever get built. But we do expect volume to come in. I think it's going to be hard to push it much faster than 2 to 4 gigawatts a year.

Unidentified Audience Member

Okay, but just going back to the 10%, not to harp on this, but so when you say that the 10% is based on some specific area, are you guys backing out Demand response or anything or are you just basically -- I mean because it just seems like a low number?

And I guess -- I understand conceptually you are saying, hey, this could be a drop-off. But when you mention like a minus 10% reserve margin, I mean is that -- I mean -- is it apples-to-apples with what PJM currently has forecasted or is it -- is this something more here. Do you follow what I am saying?

Hank Jones - *Dynegy Inc. - Chief Commercial Officer*

Yes, it is not apples-to-apples to what PJM forecasts. This is not a -- doesn't have a complicated algorithm for imports and exports out of the system. This is reflecting -- one of the comments that I made was that 8 gigawatts was deactivated since May 1 simply in Ohio, West Virginia and Western PA; most of that volume sits right there. So this is a reflection at a high level of all that capacity leaving the system.

Unidentified Audience Member

Oh, hi, it is Douglas, (inaudible) Capital. On page 36, maybe you could help me with that a bit. It is about the PJM capacity performance. And the capacity payments, that is all very alluring. But the penalties seem very severe. I mean eight hours, that is $0.10 a share based on the amount you show.

How do you even model that? I mean, it is a bad deal for bad operators, but it could be a bad deal for good operators too. I mean is there a force majeure. What are the mitigating factors? Because you could give away a lot of money here.

Bob Flexon - *Dynegy Inc. - President & CEO*

Yes, I will let either Hank or Julius (inaudible) talked about the force majeure component of it. But the point that we are really trying to highlight from the slide as well around -- and for the folks on the webcast on page 36, talking about the penalty structure of CP.

If you are a single operator or if you are someone that wants to build a new unit within PJM, this is not necessarily a good thing. From a financing standpoint on building a new unit I would think you've got to put more equity at risk because your capacity payment now has become very variable and potentially very punitive.

And if you are a single operator or you have a relatively small fleet with the penalty being at 1.5 times CONE I believe you can end up with negative capacity payments in any given year. The advantage of our fleet is that we have 60 units, so you have risk diversification.

And there are times, particularly in a very high demand period, whether that could be in the summer where you have fee rates due to the temperature of cooling water or whether that is in the winter when you have other issues with -- particularly sometimes when it is snow that creates clogging in combined cycle intakes and the like where you get [D rates] or outages or the like.

That happens in spots of the fleet, it doesn't happen to the entire fleet. It is definitely a positive for us being that we have 60 units. But if you are sitting there with just a couple of units, as we said, if the capacity market clears at $170 a megawatt day you can lose that in one day. And then you are going to go in the negative if it happens again.

PJM is forecasting approximately 30 hours -- shortage hours a year. And you can lose $170 a megawatt day in half of the time. So it is an interesting structure that is going to put pressure on units. And if you are a generator that has mostly peaking units in that market as well, this is not the market for you.

I mean if you have got a ramp time of 12 hours or something like that or you have got an LDC between you and your gas supply, that is your problem, and it is not going to be a force majeure event. So if the plant is not there when called upon. Whether it is your fault that fuel is missing, I presume also transmission outages, it is still you are wearing -- you are virtually wearing every risk. Is there anything that is a force majeure event?

Unidentified Company Representative

Yes PJM has definitely tightened up the rules (inaudible) portfolio, graphically diverse, fuel diverse and (inaudible) reliability and also build that risk into our offers.

Unidentified Audience Member

But you are confident you can like model this I guess is it really the (multiple speakers)?

Bob Flexon - *Dynegy Inc. - President & CEO*

We are confident what we can model is -- and while we are looking at every single asset that we have, every single unit and modeling what is the risk of them. We know there are certain coal units that are less reliable than others so they will be bid in differently.

We know that there is -- we have got a couple of peaking assets that we would bid in differently. And we know we have certain combined cycle units that have unfettered access to (inaudible) so they would be bid in differently. And each unit has 10 different bidding levels that you can participate.

But we have asset managers in each of the markets working with Dan and Marty making sure we understand the capabilities of each asset, where the vulnerabilities are and developing a bid strategy around it. And I say right now that is a work in progress, we don't have the answers yet. To your point, we are doing some very detailed modeling and analysis and scenario planning around that.

Hank Jones - *Dynegy Inc. - Chief Commercial Officer*

Can I make a comment, Bob? Can I make a quick comment? So just to be clear, the optimization of this wouldn't necessarily be that all your volumes cleared CP. In fact, that would not be the optimal scenario. Your pricing and risk and at a level which you are able to invest based on the premiums you receive.

But there is a tradeoff between volumes we will offer in pairs, a base auction price and a CP auction price. So I think there is -- want to make sure there is no misconception about that, that all the volume more than likely will not clear CP.

Unidentified Audience Member

(Inaudible) from Deutsche Bank. Back to slide 77. (Inaudible) 1979 -- what percentage of the PJM capacity do you see at risk?

Bob Flexon - *Dynegy Inc. - President & CEO*

Did you say 77 or 79?

Unidentified Audience Member

Our 77, your 79.

Bob Flexon - *Dynegy Inc. - President & CEO*

Oh, I didn't realize they were different numbers. Oh, that is helpful (laughter).

Unidentified Audience Member

So, the question was what percentage of PJM live capacity is at risk and also maybe related is how much is more targeted towards base capacity? And that pool is only limited to 20%, so a lot more than that around (inaudible) presumably (inaudible).

Hank Jones - *Dynegy Inc. - Chief Commercial Officer*

Sure, so the question was on slide 79, how much of the capacity in PJM is at risk for retirement. And I think that was the question. Our assessment is that that number is 10% to 15%. It is based on what we know about the operational characteristics of some of the assets and the age of the assets.

And the view is that in the past they were collecting capacity rent with no obligation to perform. So no harm no foul if they didn't make it. And I our view is that those assets will either appropriately price risk and be priced out of CP and possibly default to the base. Or they may in some cases unwittingly or unfortunately clear at CP at a level that does not adequately compensate them for the risk.

I mean part of our assumption here is that under either scenario that the decision to cease operations at these facilities will occur before a new build response ever makes it. Because you are either out of the auction and not collecting enough rent or you are getting a knockout blow in the performance three years from now. And that is when you make the decisions to exit and it is presumably before new build is able to come in behind.

Unidentified Audience Member

Just want to drill down specifically on your Ohio assets. I understand the advantage of where your plants are relative to very variable pipes. But if we fast forward with all the new pipeline built, pipeline reversal, if suddenly we are in an environment where everyone has access to sub $2 gas, what is the risk?

What do you think about pricing in that environment? And if you could frame your answer in terms of how much coal generation is actually being supplied into the market today? How much gas capacity is there in the very local markets that could potentially leapfrog any coal generation that is still being done today?

Bob Flexon - *Dynegy Inc. - President & CEO*

I will start and then let Hank tag on. But we expect over time as pipelines are built out, that differential advantage should narrow and the negative (inaudible) should flatten out as pipeline capacity is built. Hank, I don't know if you have any specifics on the capacity.

Hank Jones - *Dynegy Inc. - Chief Commercial Officer*

Sure, just to tag on to Bob's comment about the (inaudible) of the forward markets for Dominion South in calendar 2016 is just over a negative $1 versus Henry Hub and 2018 it's showing minus $0.70. So it is still viewed as a significant discount to gas at the Henry Hub in Louisiana, but the logical expectation is that gas will be relieved and move out of the system.

There is a lot of factors that would tell us that $2 gas generically is an extreme case in the future given how much incremental consumption there is expected to exports to Mexico, exports to LNG, increased petrochem demand and all the gas-fired assets that are going to replace the coal assets. There is a huge uptick in gas demand over the next five years.

So I think that provides some support for that floor, presumably at a -- if there was a sustained low cost price it would put a lot of pressure on coal units. But I would say that today we're already experiencing lower than $2 gas up there. We had gas delivered to our facility over the five days of this week at $1.30 to $1.70 per MMBtu. At the same time we are selling on-peak power at $45 plus or minus $5.

So there is a huge spark spread. And what that tells me is that the system can't survive without coal being on the margin certain hours. There just isn't enough gas-fired generation to satisfy the system. So the coal units, the cost of those units keeps the power price up. As gas prices drop our spark spreads expand.

I would expect that situation to be even more pronounced in the future as the system -- as retirements come into the system. So I think there is an extended -- we are already dealing with under $2 gas; I think there is an extended period of time here where the structural change overwhelms the gas price issue. There is not going to be enough generation during peak times to keep us out of scarcity pricing events, is our view.

Bob Flexon - *Dynegy Inc. - President & CEO*

As you said earlier, Hank, we had 8 gigawatts retire in the past month in Western PJM of coal.

Jeff Cramer - *Morgan Stanley - Analyst*

Thanks, Jeff Cramer with Morgan Stanley. Just shifting gears a little bit, just touching on IPH, obviously a pretty positive outlook here today. Just curious what in your mind it would take to pull that into the broader Dynegy structure more formally, maybe recognize some of the benefits and what those benefits are.

And then, Clint, on the capital occasion it sounds like share repurchases are going to be a big focus. But you also mentioned balance sheet improvements. Can you just kind of discuss what that might entail?

Bob Flexon - *Dynegy Inc. - President & CEO*

Well, on the IPH structure ring fence, we have no near-term plans to do anything different with IPH. We have got to get through a few hurdles along the way. We have got the Newton scrubber that needs to be built. The CapEx pull on that is in the -- towards the end of 2017 into 2018 and 2019, we have got the first tranche of debt to refi in 2018.

And then we have got to take a look at the environmental CapEx, which I think in Jeff's area he showed separately when you think about 316 B and ELG and CCR that IPH is roughly -- I think it was $230 million -- $250 million of CapEx in the later years.

But we will be exceedingly cautious about doing anything that could risk the Dynegy balance sheet. So we would have to see the capacity expectations that we have come through, the energy price volatility or higher prices come through. And a clear path to refinancing the debt in 2018 and meeting our other obligations.

So we have got a ways go before that proves itself out. Certainly the outlook today has never been better for IPH and we want to see that continue to go certainly in that direction as we enter these next couple of years. But there is no near-term plan necessarily to change the structure. Regarding the other question around the debt management, Clint, over to you.

Clint Freeland - *Dynegy Inc. - CFO*

Yes, I would say that we don't have any specific plans to use any of the excess cash to pay down debt. My only comment around that we may look to refine our leverage over time really is more going to be a function of kind of our future view on earnings and whether or not we are kind of growing into the right statistics.

There are a couple of different ways that you can kind of achieve that BB credit metric goal. And if we are growing into the right statistics then I am not sure that there is really anything to do as far as debt pay down. To the extent that that moderates some you may want to pay down a little bit of debt over time.

Again, I think we don't have any specific plans to do that, it is something that we are monitoring. But I think that is something that we will have to consider again when we think about prioritization of our capital allocation program, we want to be sure that our balance sheet and our liquidity is in the right place. And we will take a look at that over time to get the specific plans.

Mitchell Moss - *Lord Abbett - Analyst*

Mitchell Moss with Lord Abbett. Just a follow-up on the last question. So regarding IPH, does that mean that any excess cash generated we should expect it will stay in the IPH bucket going forward?

Bob Flexon - *Dynegy Inc. - President & CEO*

Yes. So the question is with IPH any excess cash flow would stay there. And for the time being that should be the assumption you work under. There is dividend blocks that the debt has already that prevented that we haven't met the threshold to clear those.

But I think in the capital allocation chart that Clint showed toward the end of this presentation the assumption around all of that is that all the cash generated IPH -- stayed with IPH to meet its obligations with really no support from the parent.

We still continue at the parent level, we see charges for the services that the corporate and operational support group provide. Historically that's been has been about $60 million a year now. With the expanded portfolio I think that drops to about $40 million a year. So that cash continually flows just on a monthly basis to the parent. And that will continue.

Mitchell Moss - *Lord Abbett - Analyst*

And just when you think about the Ontelaunee expansion, brownfield expansion, what type of uplift or better power prices or margins are you looking for to make that investment, to make that expansion?

Bob Flexon - *Dynegy Inc. - President & CEO*

Well, on the expansion on the Ontelaunee site, having -- I don't know if you are familiar with the site. It's in (inaudible) for right outside of Reading. And it is a piece of property that is vacant next to our plant, I mean it is contiguous, there is no separation by roads or anything that has been developed by (inaudible), has full permits, everything it needs to start construction. We haven't necessarily evaluated at this point in time is it a go or no go to build.

The one thing that we felt strongly about is that that site that we share with all of our infrastructure, if anybody should have that property to develop it should be us and recognizing the synergies. We haven't done the math around specifically what would the price have to be. I think more realistically we would have to take kind of a view on the market. I think basically new build economics are roughly -- on a capacity performance level it's roughly $170-ish. Is that fair, Mike, or a little --?

Unidentified Company Representative

For us.

Bob Flexon - *Dynegy Inc. - President & CEO*

Yes, for us roughly $170 a megawatt debt. We still have to refine what capital cost would be. I think you have seen recent discussions in the market, I guess PSEG talked about their -- I think they quoted $1,200-$1,300 per KW construction.

I would expect being that we have infrastructure to share that our costs would be below that. But we have to go through all that math to find out where is a sweet spot on that and is that a better alternative to just buying basically the same capacity by buying back our shares. And that is what that is going to have to compete against because that's a fairly intense capital outlay.

We would probably end of financing it -- a large portion of it at the corporate level, we would still have to decide whether that is a good use of our free cash flow or not. And that is something that we have got more work to do. We are nowhere near concluding on that. Again, we just wanted to make sure that something is going to be built on that site that we are the ones that are in the best position to do it.

Mitchell Moss - *Lord Abbett - Analyst*

Well, in some of those economics that you just mentioned, getting close to the new build, when I look at the incremental case, which is slide 94 or 96, is that -- is the incremental case reflecting something closer to some of those new build economics?

Bob Flexon - *Dynegy Inc. - President & CEO*

I would say I just quoted $170, kind of a benchmark ,that we think about where we see new investments come in. I would say showing what are probably more -- our assumptions around that is it's lower than that, it is embedded in this number.

Clint Freeland - *Dynegy Inc. - CFO*

What is embedded in the incremental case is our view of how our prices and spark spreads (inaudible).

Bob Flexon - *Dynegy Inc. - President & CEO*

Sure, it is at the capacity performance, we have an assumption in there that is lower than the $170 that I quoted.

Clint Freeland - *Dynegy Inc. - CFO*

That's right.

Bob Flexon - *Dynegy Inc. - President & CEO*

(Inaudible).

Clint Freeland - *Dynegy Inc. - CFO*

Across the fleet.

Bob Flexon - *Dynegy Inc. - President & CEO*

Yes.

Greg Gordon - *Evercore ISI - Analyst*

It is Greg Gordon again, hi. Okay, you just kind of answered one of my questions. Roughly speaking, what is baked into the 1-3? Because there is sort of two levels (multiple speakers) vectors of exposure on CP what is the price going to be relative to what you have as placeholder and how much --?

Do you expect as we move through the incremental auctions and through the BRA that you will give us a disclosure subsequent to each auction or subsequent to all three auctions as to what percentage cleared and whether that price was meaningfully different from what you baked into the guidance so we can adjust our expectations accordingly?

Bob Flexon - *Dynegy Inc. - President & CEO*

Yes, not to over commit at this point in time, but I would certainly hope we would be able to do that. We recognize, as Hank said, not all of the assets should clear and we will risk adjust our bids. And I would expect we would get some level of transparency on how much cleared, how much didn't, and we could talk about the (inaudible), what is embedded in there.

And I do think, to the extent you to have clearing prices, I would expect it would be higher than what is in those cases. But the time it comes to clear and we reach the third-quarter call in November, we should be able to give some level of transparency and what is different than what we assumed at the (inaudible).

Greg Gordon - *Evercore ISI - Analyst*

Awesome. And then one last question. The 2016 sensitivity that showed the $10 -- $10 million delta to $1 change in gas, is that simply just a linear calculation? And is that overly simplistic as you get to different breakpoints in gas price?

For instance, this year in PJM we had a significant decline in gas without a commensurate decline in power as we hit that sort of coal floor and spark spreads have widened. So if gas were to go up let's say $0.50 you might see spark spreads decline a lot but dark spreads not go up that much.

But if guys went up $1.25 you might have a much different response in the market as you get through certain breakpoints on where plants dispatch. So does this scenario analysis take into account the potential nonlinearity of that or is it simply a linear calculation?

Hank Jones - *Dynegy Inc. - Chief Commercial Officer*

That is looking at how 2016 forwards have been trading during 2015. And so, to the extent that you do see a change in market dynamics as you were just talking about, that would change that sensitivity. And so, that is what I mentioned that this is what we are seeing, and it certainly could go the other way. But it is something to keep your eye on as to whether or not that relationship continues to hold over time.

It very well may not. But that is something that we are seeing today, it is something that is affecting the sensitivity that we provided this morning. But it is something to watch, because to the extent that it does go back the other way, we certainly will be picking that up as we update our sensitivity. But I would not suggest to you, based on what we are seeing today, that that $10 million will necessarily always (inaudible).

Angie Storozynski - *Macquarie - Analyst*

Angie Storozynski, Macquarie. So I wanted to go back to slide 96, can we have apples-to-apples comparisons versus what you guys are showing now, which includes the CP payment versus just pure play flat prices for capacity and forward observable curves? How much of this $1,300 in EBITDA has in general for those unpriced products, so EP, MISO, you name it? Can you tell us if it's like $100 million, $200 million roughly?

Clint Freeland - *Dynegy Inc. - CFO*

Yes, roughly speaking it is a couple hundred million on average each year.

Bob Flexon - *Dynegy Inc. - President & CEO*

Included in that is the (multiple speakers) MISO capacity.

Clint Freeland - *Dynegy Inc. - CFO*

MISO capacity, the PJM (inaudible) transitional auction, yes.

William Frohnhoefer - *BTIG - Analyst*

Okay. Okay. Secondly, for non-growth CapEx, so inclusive of all of the environmental CapEx, what is roughly the run rate in 2016 and beyond?

Bob Flexon - *Dynegy Inc. - President & CEO*

The run rate of CapEx, roughly $250 million.

Clint Freeland - *Dynegy Inc. - CFO*

On a maintenance CapEx basis it is roughly $250 million and that may from year-to-year change as outages change over liability (inaudible).

Angie Storozynski - *Macquarie - Analyst*

But it doesn't include that environmental CapEx?

Clint Freeland - *Dynegy Inc. - CFO*

That is right, that does --.

Angie Storozynski - *Macquarie - Analyst*

That does not include it. Okay.

Bob Flexon - *Dynegy Inc. - President & CEO*

And Angie, in 2016 you will see in the appendix I think there is like an extra $50 million -- $40 million to $50 million in there for reliability type investments.

Angie Storozynski - *Macquarie - Analyst*

Okay, and lastly, this notion that you guys are keeping your energy book open because you are bullish on energy prices. But you are also bullish on capacity prices. So are you bullish on regional gas prices or are you trying to say that despite rising capacity payments and penalties associated with those capacity payments you do not expect a contraction in heat rates?

Bob Flexon - *Dynegy Inc. - President & CEO*

Angie, I will take the first shot at that and let Hank tag on after that. But our assumption, and I think what Hank tried to illustrate in his presentation, is that we are not betting on gas doing anything different than what it has been doing.

But we have been building our portfolio around and assuming is that the supply-side continues to tighten and the type of assets that are leaving versus the types that are coming in, the generation that's coming in, are very different.

And I think Hank illustrated during the polar vortex the response from wind. I think he also illustrated the response that Demand response -- how they have answered the bell with a 70% failure rate.

So what we see is there is going to be just points in time when the system is stressed, it's going to be tested like it hasn't been tested for a long time. 8 gigs just left in May out of Western PJM. MISO in a high temperature environment has a reserve margin of 7% to 8% and that is counting on 5 gigs of Demand response showing up which MISO has no control on whatsoever.

So our fundamental thesis behind keeping the energy price portion open is that the supply-side is very different than what it has been and it is going to be stressed, it is going to cause volatility.

And during those periods of volatility will be the time to layer on additional hedges, not when weather is soft and gas is kind of trading with the malaise of the weather and the sentiment that we are going to have a cool summer or a warm winter. But when the system gets stressed is when you will see us adding on positions. Hank, anything to add to that?

Hank Jones - *Dynegy Inc. - Chief Commercial Officer*

No, thank you.

Unidentified Audience Member

One last one, I swear.

Bob Flexon - *Dynegy Inc. - President & CEO*

How many questions does Julien get? Rule number two (laughter).

Julien Dumoulin-Smith - *- Analyst*

Quick clarification on the last one really, what is the profile of that [1.3]? You talk about an average over the next three years. Is it fairly flattish over the next three years, the 1.3, or is there Contango built in there? Especially given the synergy targets you talked about, locking in capacity, hedges rolling off, lots of different moving pieces. Net-net, what do you see?

Bob Flexon - *Dynegy Inc. - President & CEO*

I would say that there is some level of Contango but it is not meaningful. It is not a dramatic change from 2016 to 2018 in the base case. There is a Contango to it, but it is not really significant.

Julien Dumoulin-Smith - - *Analyst*

Perhaps said differently, you have got $200 million -- or a couple hundred million every year in potential locked in -- or potential to be locked in capacity that we just spoke about a second ago.

Bob Flexon - *Dynegy Inc. - President & CEO*

So I guess I was talking to the overall number -- not necessarily to the specific capacity component of that. I mean remember that over the next -- over that timeframe Brayton point is going out. You have got our California contract that is expiring at the end of 2016.

You have got a number of factors that are kind of coming out, but then there are other adjustments also coming in. So again, I would say overall that the trajectory, that there is a slight Contango to the numbers through time, but it is not a significant one.

Julien Dumoulin-Smith - - *Analyst*

Right. So like less than $100 million or something like that?

Bob Flexon - *Dynegy Inc. - President & CEO*

I would say that is kind of a reasonable --.

Julien Dumoulin-Smith - - *Analyst*

Okay, great, thank you.

Unidentified Audience Member

Okay, thanks. I had a question about the retail business, maybe it is for Sheree and maybe Julius on the regulatory side. Obviously it is a much smaller business than the commercial business. But it obviously has a strategic advantage, as you mentioned, with the load volume, the ability to capture higher margins and the natural hedging.

So I am just curious about some of the risk and opportunities in that business. On the regulatory side, for example, are there any regulatory risks in terms of potentially reducing competition? At the same time, I would see regulators might view it positively that you could potentially offer lower prices or create an environment of lower prices for consumers.

And then just -- obviously (inaudible) a smaller side of the business. Bob mentioned the potential to put the PB on some available space on the Illinois site. I am just curious, is that part of your strategy of bundling services, is that kind of how you see that?

Bob Flexon - *Dynegy Inc. - President & CEO*

Sheree, did you catch all of it?

Sheree Petrone - *Dynegy Inc. - EVP, Retail*

Yes. So (inaudible) your first question was about regulation and whether or not there is any risk of reregulation or something like that in the retail markets. I guess I would say that retail markets are successful because wholesale markets are and vice versa. So they go hand-in-hand.

So to the extent that we have a lot of work that we are doing in the wholesale environment to protect the market, that is very helpful to maintaining a structure for the retail side. And we talk to the regulators quite often as well and in the markets where we compete the regulators and the states are very interested in regulation. They see the value of competition to provide good price for customers.

And then the second question, as far as whether or not we get into clean energy products or such for retail customers, we sell a lot of RECs or renewable energy credits to our retail customers that are voluntary purchases. There are certain communities that are extremely interested in having green energy. So that is why we are looking on the strategic side about what sorts of things could we do as a generator in that space.

And we are not -- we are probably not taking an approach that a lot of our competition does to really get into the customer side, sort of value added products and services related to that are getting into rooftop solar or those sorts of things.

But we are trying to look at ways where our generation and the things that we can do to enhance our generation suite could add value to our products that we offer to customers. So, we are thinking about it. We're just not quite sure how it fits with the generator because we are not interested in some of those other types of things that retailers with a lot of value added services do.

Unidentified Audience Member

Thank you.

Bob Flexon - *Dynegy Inc. - President & CEO*

Thanks, Sheree. I mean retail or anything like that would have to compete against capital just like everything else. Just because we like Sheree doesn't mean she has to get any special favors. Andy, how are we on time?

Andy Smith - *Dynegy Inc. - Managing Director, IR*

(inaudible) we have got time for one, maybe two more questions.

Bob Flexon - *Dynegy Inc. - President & CEO*

Okay. Anymore? A question up front.

Evan Kramer - *Silver Point - Analyst*

Evan Kramer, Silver Point. You see from 2014 to your 2016 to 2018 estimated average that the O&M per megawatt hours actually stepping up despite the fact see synergies coming in and the price savings coming in. Is there still meaningful difference in the O&M per megawatt hour on the Duke and EPC side of the house versus the legacy Dynegy and IPH portfolio?

Bob Flexon - *Dynegy Inc. - President & CEO*

I would say not so much on the ECP side of the house, maybe that is obviously heavy gas weighted and tends to have less. On the Duke or the coal portfolio within the Duke assets is where more of the opportunity but certainly (inaudible). I don't know if there is any --.

Evan Kramer - *Silver Point - Analyst*

Could you speak to any specific numbers or -- at this time?

Bob Flexon - *Dynegy Inc. - President & CEO*

In terms of the cost per megawatt on [those deals]? Is there anything particular?

Sheree Petrone - *Dynegy Inc. - EVP, Retail*

No, I mean I do know we are looking specifically at Zimmer and --.

Unidentified Company Representative

The liability issues at Zimmer in particular probably raise that level up a little bit.

Bob Flexon - *Dynegy Inc. - President & CEO*

Yes and that is probably the biggest -- maybe the biggest impact of all is just when you look at the denominator, the liability hours should be much higher. Because you take a couple of the units and have forced outages, right? We talked about Zimmer having some of the most opportunity of the forced outage rate of 25%.

Unidentified Company Representative

North of 20%.

Bob Flexon - *Dynegy Inc. - President & CEO*

So that plant should not be having a planned availability factor of 70% which is where it is today. It should be up where the rest of the fleet is up closer to 90%.

So I would say that the Duke portfolio historically has relied more on contractors than what we do, and that might have some cost impact. I think the other element and probably the bigger half of it is the amount of megawatt hours you are getting out of the units.

Bob Flexon - *Dynegy Inc. - President & CEO*

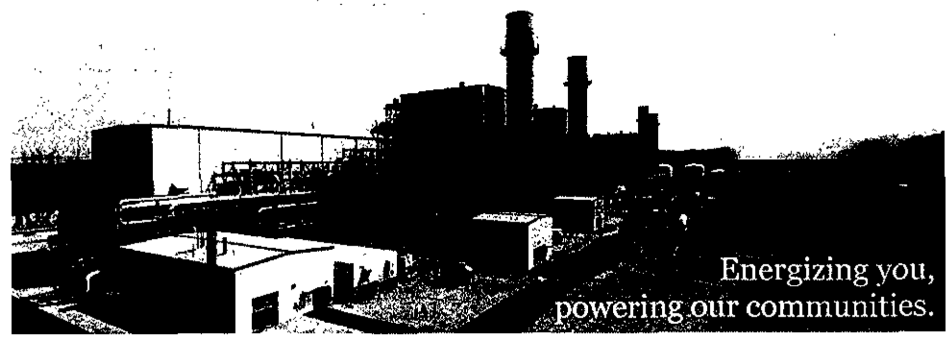
One final question? Maybe not. Again, I would like to thank everybody for hanging in there with us and going through 100 plus PowerPoint slides. We appreciate your support and attention. Thank you.

DYNEGY

Investor Day 2015

June 25, 2015

Hanging Rock Energy Facility



Forward Looking Statements

Cautionary Statement Regarding Forward-Looking Statements

This presentation contains statements reflecting assumptions, expectations, projections, intentions or beliefs about future events that are intended as "forward looking statements." You can identify these statements by the fact that they do not relate strictly to historical or current facts. Management cautions that any or all of Dynegy's forward-looking statements may turn out to be wrong. Please read Dynegy's annual, quarterly and current reports filed under the Securities Exchange Act of 1934, including its 2014 Form 10-K, and First Quarter 2015 Form 10Q for additional information about the risks, uncertainties and other factors affecting these forward-looking statements and Dynegy generally. Dynegy's actual future results may vary materially from those expressed or implied in any forward-looking statements. All of Dynegy's forward-looking statements, whether written or oral, are expressly qualified by these cautionary statements and any other cautionary statements that may accompany such forward-looking statements. In addition, Dynegy disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date hereof.

Non-GAAP Financial Measures

This presentation contains non-GAAP financial measures including EBITDA and Adjusted EBITDA. Reconciliations of these measures to the most directly comparable GAAP financial measures to the extent available without unreasonable effort are contained herein. To the extent required, statements disclosing the definitions, utility and purposes of these measures are set forth in Item 2.02 to our current report on Form 8-K filed with the SEC on May 6, 2015, which is available on our website free of charge, www.dynegy.com.

EXHIBIT
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16
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DYNEGY

Investor Day Agenda

1.	Investing in Dynegy	Bob Flexon
2.	Integration, Synergies & PRIDE	Carolyn Burke
3.	Regulatory Policy	Julius Cox
4.	Operations Support	Jeff Coyle
	Panel Q&A	
Break		
5.	Retail	Sheree Petrone
6.	Commercial	Hank Jones
7.	Financial	Clint Freeland
8.	Closing Remarks	Bob Flexon
	Panel Q&A	

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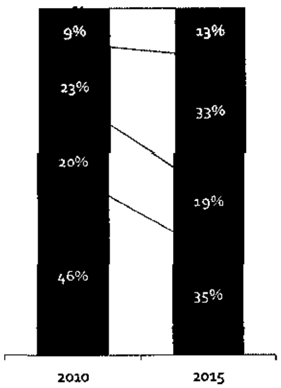
Investing in Dynegy

Bob Flexon
President and CEO

Independence Energy Facility

2015 – A Watershed Year for the Industry

U.S. Power Generation by Fuel Type[1]
Percent of total MWs



2015 Ushers in Dramatically Different Generation Mix

- Most coal retirements ever in 2015 (over 20 GW), concentrated in East and Midwest
- Most gas burn from the power sector ever
- Most renewable build ever (almost 20 GW), concentrated in the West

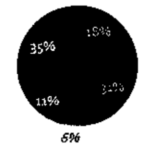
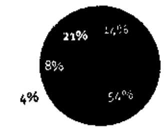
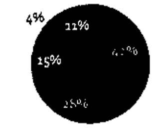
The New Normal

- A less stable power system with higher power prices and increased market volatility
- Harsher penalties for older, less reliable plants
- Compensation for low-cost, environmentally compliant and reliable generators

The US power industry is undergoing a profound structural shift as baseload coal retires and is replaced with less reliable resources

[1] Wood Mackenzie, February 2015

A Look Back – Investor Day Snapshots

	January 2013	April 2014	June 2015
MWs	9,751	13,120	25,758
Markets % Generation Capacity (MWs) PJM MISO ISO-NE NY-ISO CAISO	 35% 11% 6%	 21% 8% 4% 54%	 4% 11% 15%
Adjusted EBITDA ($ MM)[1]	$227	$347	$825 - $1,025[2]
ROIC	5.5%	6.8%	10.8%
Net Debt/EBITDA	~2.4X	~2.1X	~4.9X[3]
Retail Volumes (MWh)	0	~13 MM	~22 MM
PRIDE Achievements (Incremental)	$39 MM EBITDA improvement $191 MM B/S improvement	$90 MM EBITDA improvement $93 MM B/S improvement	$45 MM EBITDA improvement $73 MM B/S improvement
Shares Outstanding	100 MM	100 MM	128 MM 140 MM fully diluted[4]

Over past two years Dynegy has enhanced its diversity and profitably scaled its presence in the most attractive power markets

[1] Adjusted EBITDA is a non-GAAP measure, reconciliations to GAAP can be found in the Appendix; [2] Reflects only 9 months of Duke/ECP acquisitions; [3] Based on 2015 Adjusted EBITDA guidance as presented on 05/06/2015, annualized to include 12 months of Duke/ECP acquisitions; [4] Fully diluted shares reflects maximum potential dilution from Mandatory Convertible Preferred conversion

Beyond 2015 – Continued Industry Instability

Capacity Exiting the System

	Wave 1 2010 - 2015	Wave 2 2016 - 2020
Key Drivers	• Environmental regulations required significant capital investment for coal plants • Low natural gas prices pressured economics	• Performance incentive products in PJM and ISO-NE render less reliable units uneconomic • Uncertain status of Demand Response when held to higher performance standard
Impact	• ~90 GW of mostly coal-fired generation retirements throughout the U.S. (~15% of U.S. coal capacity) • ~50 GW retire in Dynegy's key markets	• Up to 25% of ISO-NE and 10-15% of PJM generation capacity at risk of retirement • Likely rationalization of Demand Response
Lasting Repercussions	✓ **Lower reserve margins** ✓ **Higher capacity prices** ✓ **Volatile power prices**	

A second wave of capacity leaving the system adds additional instability through the balance of the decade

Dynegy Investment Thesis

1 Multiple Avenues for Upside

- Substantial exposure to tightening and reforming capacity markets
- Positioned to capture upside from improving power prices and increased volatility
- PRIDE and synergy capture

2 Limited Downside Risk

- Reliable low-cost portfolio with fuel and geographic diversity
- Manageable environmental spend
- Positive Free Cash Flow across a wide range of commodity environments

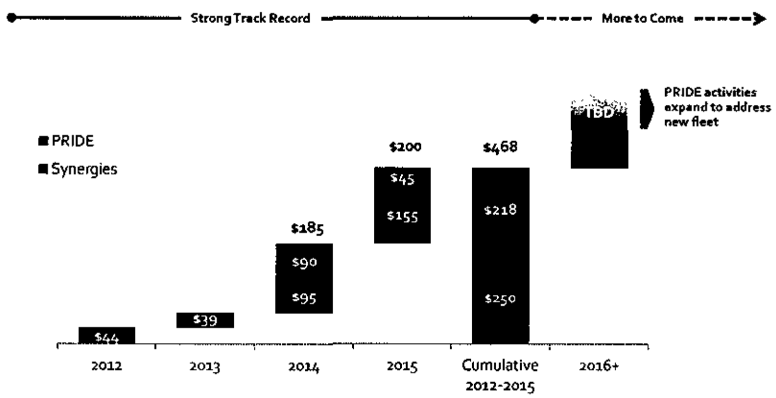
3 Capital Allocation Opportunities

- Strong balance sheet and ample liquidity
- Multiple low-cost expansions underway
- $1.1-2.0 billion of excess capital available for allocation over 2016-2018 timeframe

Dynegy – a compelling risk/reward profile

PRIDE – A Core Competency

Run-rate EBITDA Generated by PRIDE and Synergy Capture ($ MM)



Earnings generated through internal efforts drive additional value

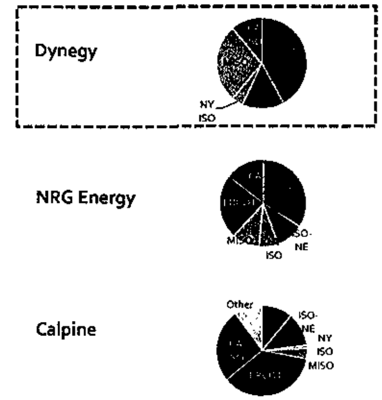
DYNEGY

Substantial Exposure to Most Compelling Capacity Markets

Capacity Market Design "Heat Map"

	PJM	ISO-NE	NYISO	MISO	ERCOT	CAISO
Dynegy MWs	~11,000	~4,000	~1,000	~7,000	-	~2,700
Capacity Market						
Capacity Market Design						
Stable Market Rules						
Performance Incentives						
Overall Rating						

IPP Capacity Market Exposure[1]
MWs Capacity by Market



Dynegy offers the best overall leverage to high value capacity markets

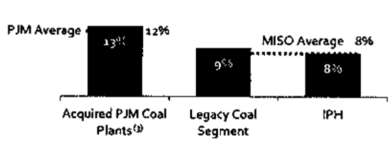
[1] Company filings

DYNEGY

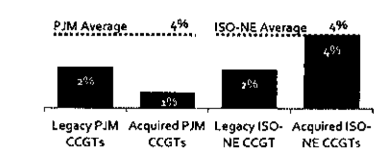
Reliable Low-Cost Portfolio

Reliability

Baseload Coal EFORd Rate[1][2]

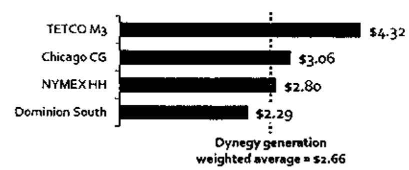


CCGT EFORd Rate[4]

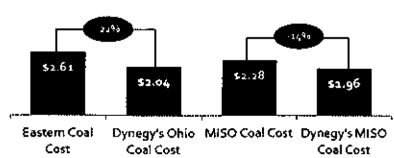


Low Fuel Cost Advantage

2015 Delivered Gas Prices[5] ($/MMBtu)



2014 Delivered Coal Prices[6] ($/MMBtu)



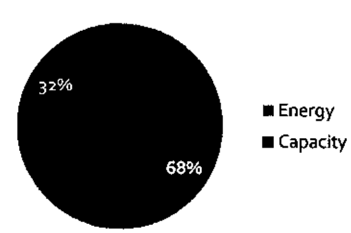
Reliability and low fuel cost provide competitive advantage

[1] EFORd (Equivalent Demand Forced Outage Rate) is the probability a generation asset will fail when needed, [2] PJM and MISO, [3] Acquired PJM coal average excludes Zimmer, whose 2014 EFORd was driven by lack of natural gas for startup fuel; re-commissioning dual fuel startup capability underway; [4] ISO-NE, [5] Reflects YTD prices through May 1; Dynegy average reflects PJM fleet delivered fuel cost for that same period, [6] Ventyx and Dynegy operating data

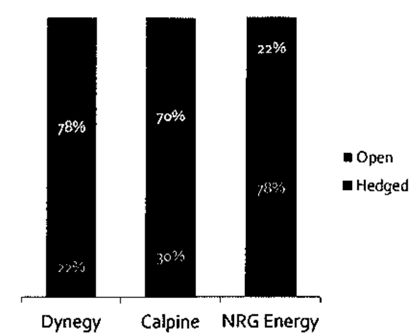
DYNEGY

Positioned to Capture Improving Prices

Dynegy Gross Margin Composition by Type[1]
2016 Estimate



2016 Energy Hedge Positions[2]
Dynegy versus Peer Group



Strong core of capacity earnings allows more open energy position to leverage improving power prices

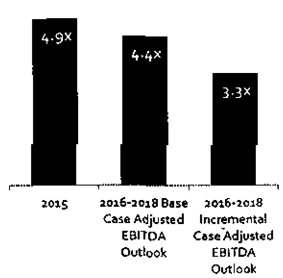
[1] Gross Margin from Energy sales includes Retail business; see Finance section for additional information
[2] Company filings for CPN and NRG; Dynegy hedge position as of 05/13/2015; Dynegy and CPN based on volumetric hedges; NRG based on hedged gas price exposure (heat rate exposure 43% hedged)

DYNEGY

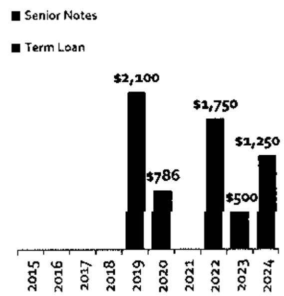
Strong Balance Sheet

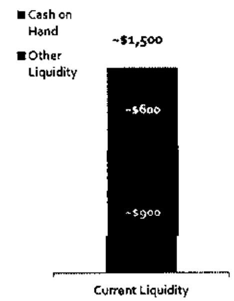
Healthy Capital Structure	No Near-Term Maturities	Ample Liquidity

Net Debt/EBITDA[1][2]



Debt Maturities[3] ($ MM)





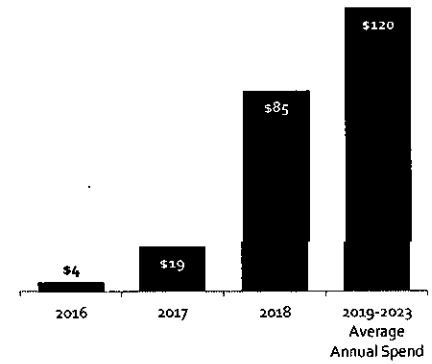
- Approximately $1.5 billion in current liquidity
- Cash on hand of ~$600 million

Strong balance sheet and liquidity provide strong foundation

(1) Excludes IPH; Projections based on sum of • Midpoint of 2015 Adjusted EBITDA guidance as presented on May 6, 2015 and • 1Q15 Adjusted EBITDA not realized due to delayed acquisition closing, 2015 Net Debt/EBITDA based on current cash balance; 2016-2018 projections assumes cash builds on the balance sheet with no capital allocation decisions; (2) See Finance section for more detail, (3) Excludes IPH

Environmental Spending

Spending on Major Environmental Rules[1]
316(b), Effluent Limit Guidelines, and Coal Combustion Residuals ($ MM)



Compliance Costs for Three Major Environmental Rules

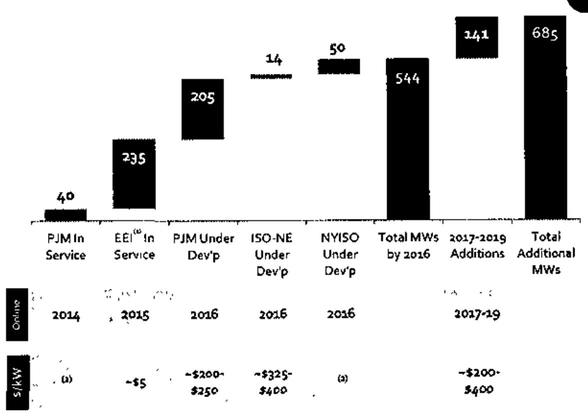
- Projected spend on 316(b), Effluent Limit Guidelines, and Coal Combustion Residuals for the entire fleet
- Spend is weighted toward the end of the decade

Capital spending to comply with major rules is expected to be manageable

(1) Includes environmental Capital Spending as well as ARO spending

Low-Cost Expansions

Capacity Uprates
MWs of Additional Capacity by Market



Equivalent of adding almost a new CCGT for a fraction of cost and time to market of new build

Competitive Cost Advantage

- Structuring expansions and uprates under existing LTSA agreements
- IRRs in the high double-digits
- Abbreviated payback period

Brownfield Development Under Consideration

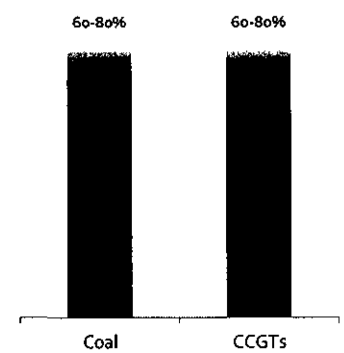
- Acquired the development rights for a site adjacent to Ontelaunee
- Fully permitted ~750 MW site

Capacity additions offer high double-digit returns and short payback periods

(1) EEI can sell into TVA, KU, or MISO; (2) Confidential

Positive FCF in Range of Commodity Environments

Dynegy 2016E Average Capacity Factors by Fuel Type[1]



Coal and Gas Portfolios Create Natural Hedge

- Dynegy's coal plants and majority of its CCGTs run as baseload units
- Balance of coal and natural gas in the portfolio is effectively a natural hedge
- In higher natural gas price environments, coal plants run at higher capacity factors; in lower natural gas price environments, CCGTs run at higher capacity factors

Reliability

- Coal and Gas fleet EFORd rates are below, or on par with, market averages

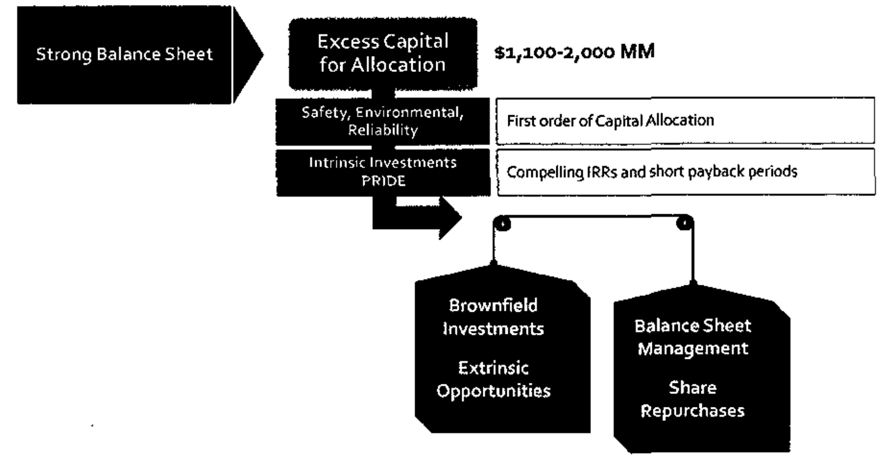
Low Cost Structure

- Locationally advantaged natural gas fleet provides access to inexpensive Marcellus/Utica gas
- Rail contracts and fuel blending keep coal costs low
- Flat G&A and O&M spend profile
- Manageable capital expenditure outlook
- Ability to shield cash taxes with NOLs

High capacity factors complement low cost structure and lead to positive Free Cash Flow across a range of commodity environments

(1) CCGTs excludes Casco Bay

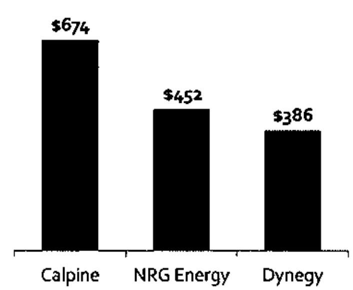
Capital Allocation Opportunities



First phase of capital allocation program to be announced later this year

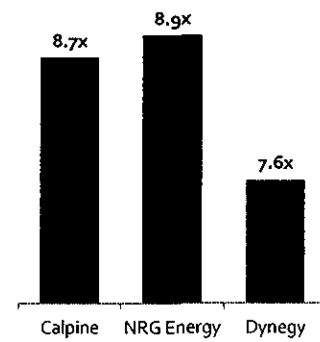
IPP Peer Comparison

Implied $/kW[1]



Fleet Composition	Calpine	NRG Energy	Dynegy
CCGT	85%	13%	37%
Coal	0%	35%	48%
CT/Oil	12%	45%	15%
Renewables	3%	5%	0%

EV/EBITDA[2]

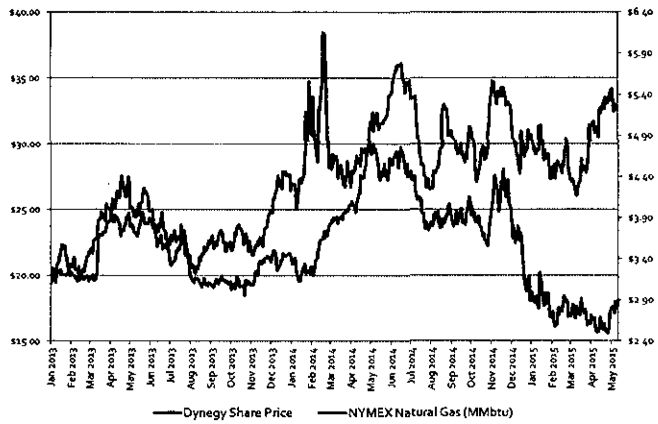


Dynegy average FCF Yield over the 2016-2018 planning period of 9% to 16%

[1] Reflects enterprise value based on stock price as of 6/16/2015 and is adjusted for the NPV of hedges and planned environmental capex; NRG and DYN enterprise values net of estimated value of retail businesses and NRG Yield; NRG asset breakdown excludes 2% nuclear, see Appendix for detailed calculations, [2] Share price as of 6/16/2015 CPN and NRG calculations based on 2017 consensus EBITDA and 1Q15 SEC filings, Dynegy cash balance adjusted for pro forma cash post-closing of acquisitions and EBITDA reflects the midpoint of the 2016-2018 Adjusted EBITDA outlook

Not Just a Natural Gas Play

Dynegy Share Price Performance vs. NYMEX Natural Gas



Key Drivers of Decoupling

- Earnings from synergies and PRIDE
- Tightening reserve margins
- Increasing gross margin from improving capacity markets
- Wholesale portfolio channels to market
- Locational advantage of natural gas portfolio to lower-cost fuel
- Correlation between natural gas and power in Dynegy's key markets

Tightening capacity markets and strong performance of natural gas fleet partially offsets impact of low commodity pricing on our coal fleet

Summary

- Power industry undergoing profound structural shift
- Dynegy is well positioned to "win" in the new environment in both capacity and energy markets
- Limited risk due to geographic and fuel diversity, PRIDE and low-cost competitive advantage
- Estimated $1,100-2,000 MM in excess capital available for allocation between 2016 and 2018

DYNEGY

Integration, Synergies & PRIDE

Carolyn Burke
EVP, Business Operations and Systems

Disciplined Approach to Integration

	Integration Leading Practices	Dynegy Implementation	Status
1.	Speed over elegance	Prepared to go-live as of December 1, 2014	✓
2.	Create a command and control Integration Management Office	Dedicated Chief Integration Officer with named work stream leads	✓
3.	Maintain focus on running core business	Backfilled where necessary	✓
4.	Immediately stabilize the workforce and manage critical talent	Organization leadership announced and employee notifications in November	✓
5.	Manage and control customer, partner, channel, and regulatory	Active outreach to key regulators, ISOs, suppliers, and customers	✓
6.	Establish a clear IT strategy	One system – Dynegy's	✓
7.	Expand and front-load synergies	30% of synergies in first six months; 60% by end of 2016	✓
8.	Address cultural differences	Senior leadership site visits week-one, leadership offsite early June	✓

Day One Readiness for Seamless Integration

Disciplined approach to integration essential to capturing synergies and maximizing transaction value

Integration Accomplishments

Focus Area	Goal	Achievement
Operations and IT Systems	• Execute a seamless transition of the operations and IT systems	• 118 IT systems (over 95%) converted with no business interruption; two remaining system conversions to be completed by year-end
Employees	• Utilized Onsite Action Teams at each new plant • Channels established to discover and quickly address new employee issues • Training to introduce Dynegy processes and culture	• Approximately 1,000 total employees on-boarded with no interruption of payroll or benefits – 6 new union relationships and 453 new union employees • 99.4% retention rate through June 2015
Customers & Counterparties	• Provided constant communication and information to allow a smooth transition of Retail customers • Maintained constant contact with all relevant counterparties	• 3,012 trades imported, representing 150 Wholesale contracts

Day One readiness resulted in Transition Services cost of less than $3 million

Controlling the Cost Structure

PRIDE Program → IPH Acquisition → Duke/ECP Acquisition

	2010	2013	2014	2016-2018E Average
Annual O&M[1] ($ MM)	$330	$307	$469	~$965
Annual G&A ($ MM)	$137	$86	$100	$130
Generation (MM MWh)	38.7	39.0	61.2	125
O&M per MWh	$8.53	$7.87	$7.66	$7.72
G&A per MWh	$3.54	$2.21	$1.63	$1.04

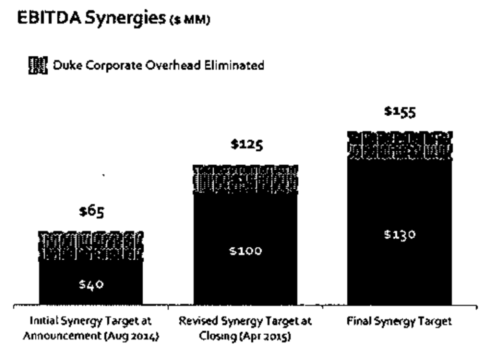
O&M Cost Per MWh Held Flat

Overhead Cost Per MWh Cut by ~70%

Leveraging the efficiency and scale of the Dynegy platform

[1] Excludes retail O&M

Transaction Synergies



Synergies Defined
- Improvement in gross margin, expenses, or balance sheet:
  - At any acquired plant due to Dynegy's expertise
  - At any legacy plant due to Duke or EquiPower expertise
  - Captured within the 2015-2018 timeframe
- Synergies exclude:
  - Improvements at Dynegy plants due to Dynegy's efforts/expertise (captured in PRIDE)
  - Non-recurring cost savings

Potential Further Improvements Captured in PRIDE
- Additional procurement savings
- Barging and coal handling
- Joint Operated Unit operational efficiencies
- Refined coal and coal blending at newly acquired sites

Significant transaction synergies

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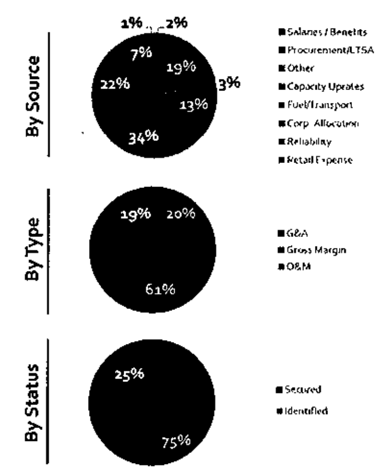
Breakdown of Transaction EBITDA Synergies



Broad-based; Most Significant Areas Include:
- **Fuel and fuel transportation:** $51 MM - renegotiated rail contracts for Kincaid, Joppa, and Duck Creek; associated increased plant dispatch
- **Corporate allocations:** $35 MM - Duke and EquiPower corporate allocations; Joint Operated Units operating services allocations
- **Procurement:** Primarily $15 MM in plant insurance savings and $10 MM in LTSA uprates

Majority Captured in Gross Margin
- **Gross margin:** $95 MM - mostly fuel, fuel transportation, and LTSA improvements
- **G&A:** Duke and EquiPower corporate allocations
- **O&M:** Plant insurance and Joint Operated Unit service allocations
- Three-quarters of synergies already secured

$ MM	2015	2016	2017	2018
Synergies Run Rate	$61	$95	$117	$155
Incremental Cost to Achieve [1]	$31	$15	$24	$9

Creating shareholder value by leveraging the Dynegy platform

[1] 2016-2017 cost to achieve primarily associated with planned capacity uprates

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Integration, Synergies & PRIDE Summary

- Disciplined approach and implementation of leading practices were key to seamless Day One integration
- Transition Services cost held to $3 million
- Acquisitions have further leveraged Dynegy platform, improving efficiency
- Raised initial EBITDA synergies target from $40 million to $130 million today

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Regulatory Policy

Julius Cox
Chief Administrative Officer

EPA's Mercury Air Toxics Standards (MATS)

Impact on U.S. Generation Fleet

No Change in Expected MATS Retirements

- Retirement decision driven by cost of multiple environmental regulations combined with low commodity prices, not just MATS
- Retirement decisions largely made; difficult to undo
- *Assets did not clear in three-year forward PJM auction*
- Non-compliant units likely earn little energy margin

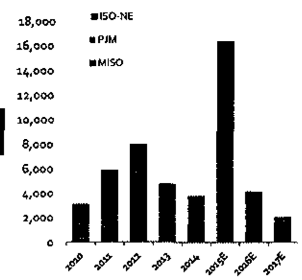
Impact on Dynegy

Dynegy's Plants are MATS Compliant

- Energy and capacity prices expected to respond to the retirement of non-compliant plants
- Higher energy and capacity prices will compensate Dynegy for its investment in environmental compliance

2015 Record Number of Coal Plant Retirements

Historical and Projected Asset Retirements by Market[1] (MWs)



Supreme Court decision unlikely to affect planned retirements

[1] MISO, PJM, ISO-NE

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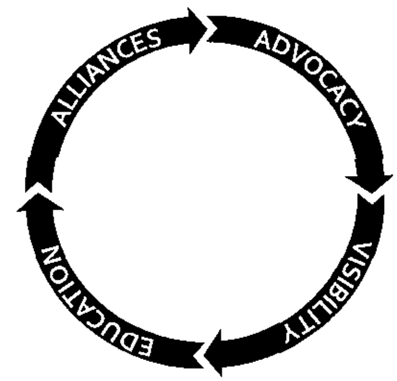
Regulatory Advocacy



Opposition to Out-of-Market Subsidies

- Exelon nuclear subsidies legislation in Illinois delayed
  - Engaged key legislators and policy makers to stress the destructive market impact of out-of-market subsidies
  - Engaged key parties to leverage advocacy
- Ohio generators seeking out-of-market PPAs
  - Providing a dissenting view on the competitive Ohio market from a company that invested nearly $3 billion in the state

Advocate for MISO Market Reforms

- Regulated jurisdictions mask true capacity costs
  - Embedded capacity charges in regulated MISO states average ~$300 per MW-day
  - Recent Zone 4 auction result ($150 per MW-day) consistent with other competitive markets
- Push for sloped demand curve, offer caps, and MOPR, which will provide just and reasonable rates for both suppliers and consumers

Dynegy advocates for appropriate environmental policies and constructive market design that support competitive markets

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Effluent Limit Guidelines (ELG)

Wastewater Streams Addressed	US EPA Preferred Technologies
FGD Wastewater	Best Professional Judgment, Chemical Precipitation + Biological Treatment
Fly Ash Transport Water	Dry Handling
Bottom Ash Transport Water	Impoundment, Dry Handling for units >400 MW
Combustion Residual Leachate	Impoundment
FGMC Wastewater	Dry Handling
Gasification Wastewater	Evaporation
Nonchemical Metal Cleaning Waste	Chemical Precipitation

Compliance Assumptions

- Final ELG rule expected September 2015; expect final rule consistent with EPA guidance
- Dynegy's compliance period begins in 2018, coincident with NPDES (water discharge) permit cycle
- Units smaller than 400 MWs exempt from dry bottom ash handling
- Compliance with Coal Combustion Residuals rule facilitates compliance with Effluent Limit Guidelines and vice-versa

Advocacy Efforts

- Dynegy provided detailed comments to US EPA, along with supporting industry comments
- Dynegy continues advocacy primarily through its two trade associations

ELG rule assumptions remain consistent with prior expectations

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Regulatory Landscape

Cost Drivers

Environmental Regulations	Status
Mercury Air Toxics Standards (MATS)	In Compliance
Coal Combustion Residuals (CCR)	Initiated Compliance Plans
Effluent Limit Guidelines (ELG)	Rule Expected September 2015
Clean Power Plan (CPP)	Rule Expected Summer 2015

Revenue Drivers

Market Design	Status
ISO-NE Sloped Demand Curve/Performance Incentive	Implemented
PJM Capacity Performance	Approved and Developing Strategy
MISO Market Design Improvements	Ongoing
Prevent Out-of-Market Subsidies	Ongoing

Supply/Demand Fundamentals	Status
Hold Demand Response to Generator Standards	Decision Expected December 2015
Advocate for Fair and Equitable Market Rules	Ongoing
Provide Alternatives to New Build	Ongoing

Dynegy's Regulatory efforts are focused on key drivers of revenue and cost

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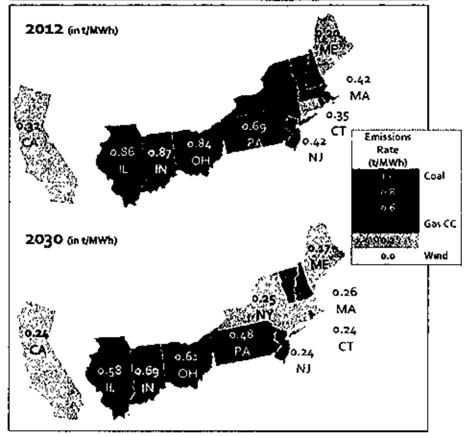
EPA Clean Power Plan (CPP) Proposal

Current and Proposed CO_2 Adj. Emissions Rates



Rule in Current Form Unworkable

- Improving coal plant heat rate by 6% is not technically feasible
- Redispatch of CCGT fleet ignores realities of generation infrastructure and supply mix
- Mixed historical results from Energy Efficiency
- State-by-state emissions limits will lead to both carbon leakage and shifting of jobs from one state to another
- Represents unprecedented effort to regulate activity outside the power plant fence line

Dynegy Managing Risk

- Portfolio has shifted to states and regions expected to meet CO_2 targets
- Offset programs such as beneficial re-use of CCR contribute to lowering CO_2 in atmosphere
- Actively working with key states on appropriate compliance pathways

Dynegy positioning itself for the Clean Power Plan to be an opportunity rather than a threat

Source: EPA Clean Power Plan

Focus on Improving Market Design

~90% of Dynegy's Generating Fleet

	PJM	ISO-NE	NYISO	MISO	ERCOT	CAISO
Dynegy MWs % of total	*~11,000 MW 42%*	*~4,000 MW 15%*	*~1,000 MW 4%*	*~7,000 28%*	*N/A*	*~2,700 MW 11%*
High Scarcity Price Caps						
Capacity Market						
Capacity Market Design						
Stable Market Rules						
Performance Incentives						

Putting regulatory resources into the markets that matter most

PJM Capacity Performance Product

Status Update	• FERC accepted PJM's Capacity Performance mechanism on June 9, 2015 • 2018/2019 Planning Year auction for Capacity Performance expected to commence August 10, 2015 • Transitional auctions will commence July 27, 2015 and August 3, 2015, respectively – PJM will procure 60% Capacity Performance for Planning Year 2016/2017 – PJM will procure 70% Capacity Performance for Planning Year 2017/2018
Notable Elements of the Final Design	• Offer caps reduced based on Independent Market Monitor recommendations – Balancing Factor of 85% applied to offer caps – Balancing Factor modification adopted to recognize bonus payments to generators for over performance – Reduces default offer cap to \$272 per MW-day from \$320 per MW-day in the initial proposals (ComEd LDA)

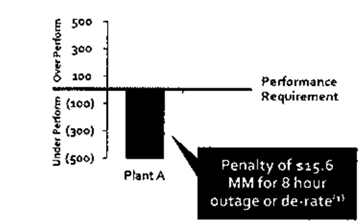
Final Capacity Performance market design retains the elements necessary for Dynegy to be compensated for its cost of providing reliability

Note: As in MISO, generator owners will be able to request a unit-specific offer cap greater than net CONE x BF from Independent Market Monitor and PJM; must be approved by such

PJM Capacity Performance – Portfolio Effect

Concentrated Risk — Owner of Single Asset

Single 500 MW Plant Outage

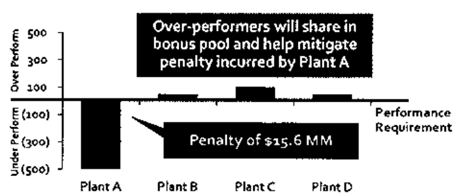


Single Assets Face Significant Risks

- Forced outages or derates expose single plants to significant penalties with no market offsets
- Inability to perform during a Capacity Performance event would subject the plant in the example above to a penalty of \$15.6 MM, which would be shared as a bonus by over-performers

Diversified Risk — Owner of Portfolio of Assets

Portfolio of Plants with Single 500 MW Plant Outage



Portfolio Mitigates Risk and Creates Opportunity

- With a portfolio of plants, one or more plants can be under-performing, while other plants are over-performing
- In the example above, plants B, C, and D over-perform and earn bonuses that mitigate the penalty incurred by Plant A
- The remainder of the bonus pool is shared among the other over-performing assets in PJM

Dynegy has significant risk diversification with a fleet of 60 units across PJM

[1] \$3,897 x 500 MW underperformance x 8 hours = \$15.6 MM; does not include real time energy market buy-back

MISO Capacity Market Design – Offer Cap

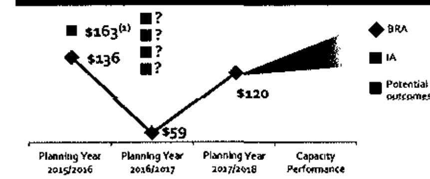
MISO Offer Cap

The MISO default offer cap is traditionally linked to PJM's RTO capacity price in the Base Residual Auction (BRA), which represents the lost opportunity cost of not exporting capacity to PJM

$ per MW-day

PY	PJM RTO Clearing Price	+	Cost of Trans to PJM	+	10% of CONE	=	MISO Offer Cap
15/16	$136		$19		$25		$180
16/17	$59		TBD		TBD		~$100
17/18	$120		TBD		TBD		~$165

PJM RTO Clearing Prices ($/MW-day)



Incremental/Transitional Auctions and Capacity Performance Can Influence the Offer Cap
- PJM Incremental (IA) and/or Transitional Auctions (TA) are expected to clear above the BRA, and also represent lost opportunity cost of not exporting to PJM
- This may prompt the Market Monitor to revise the Offer Cap

Offer Cap Exemptions Possible
- The MISO Independent Market Monitor can authorize offers in excess of the cap based on company requests
- Dynegy is evaluating exemption requests

MISO Capacity Auction Offer Cap may experience a temporary dip for the 2016/2017 Planning Year

[1] $163 per MW-day was the clearing price for the third Planning Year 2015/2016 Incremental Auction

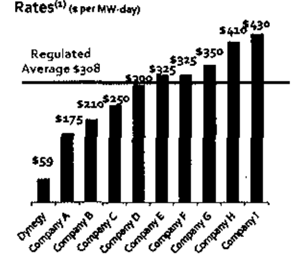
MISO Mixes Competitive and Regulated States

Dominated by Regulated Utilities | **Uneven Capacity Compensation** | **Weak Economic Signals**

MISO Footprint

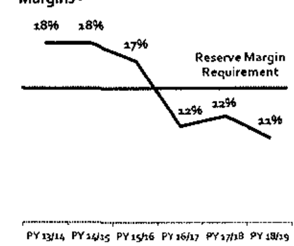
- MISO administers markets in all or part of 15 states
- Illinois is the sole fully restructured and competitive state in the 15 MISO states

Implied Capacity Prices in Regulated Rates[1] ($ per MW-day)



- On average, regulated utilities in MISO earn more than $300/MW-day for capacity, embedded in their rates
- For Planning Year 15/16 Dynegy is earning capacity payments of only $59 per MW-day[2]

MISO Classic Projected Reserve Margins[3]



- In spite of looming shortfalls resulting from coal plant retirements, MISO's capacity market has yet to send economic signals to attract new build

The MISO market includes elements of competitive market design yet is dominated by regulated utilities that do not rely on the market for revenue

[1] Calculated through rate base charges for maintenance, depreciation and capital; Source: publicly available filings; [2] Weighted average capacity price earned by Dynegy in MISO including auction and bilateral sales; [3] Dynegy Strategic Market Analysis

Hybrid Model – Caught in the Middle

Regulated Utility Model
- \+ Vertical integration simplifies decision-making
- \+ Familiar
- — Inefficient
- — Expensive for consumers
- — Less innovative
- — Ratepayers bear risk

Status Quo

Hybrid Model
- — Divergent interests lead to conflicted market design
- — Interference with market signals distorts economic incentives
- — Unclear responsibility for decision-making
- — Volatility without efficiency

Competitive Market Model
- \+ Drives efficiency by rewarding the most *effective suppliers*
- \+ Lower prices and additional choices for consumers
- \+ Drives innovation
- \+ Private investors bear risk
- — Less familiar

Re-regulate

With the Status Quo, generation in Southern Illinois is at risk of retirement

Illinois Has a Choice

Re-design
(Carve out Zone 4 or join PJM)

The status quo is not sustainable

Regulatory Policy Summary

- Advocate for market design that supports competitive markets
- Engaged with key stakeholders to develop appropriate environmental regulations
- Improved market design in PJM and ISO-NE reward reliability
- Illinois needs to address unsustainable Status Quo in MISO market

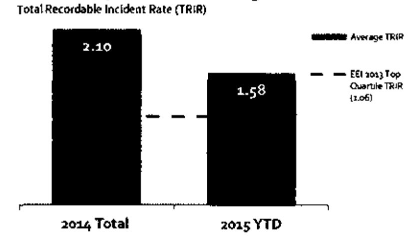
Operations Support

Jeff Coyle
VP, Operations Support

Energizing you, powering our communities.

DYNEGY

Employee Safety



2015YTD TRIR ranks in 2nd Quartile of EEI index

Improving Employee Safety
- Majority of injuries are bruises, strains, and sprains
- Most injuries occurring during routine tasks
- Additional training for supervisors and employees to increase awareness and address complacency

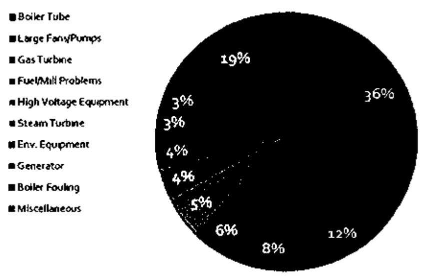
Seasonal Safety
- Best practices and preparation improved results
- Summer 2014 had zero hot weather recordable incidents
- Winter 2014-15 had zero cold weather recordable incidents
- Summer 2015 planning and preparation in place

OSHA Voluntary Protection Program (VPP)
- Six VPP status plants
  - Dighton, MASSPOWER, Lake Road, Milford, Liberty, and Ontelaunee currently hold VPP status
- Two VPP applications submitted in 1Q2015
  - Casco Bay and Hennepin
- Four VPP plant preparations in progress
  - Kendall, Independence, Havana, and Newton
- Goal for two to four additional plants to apply annually

Safety is our highest value

Improving Plant Reliability

Causes of Dynegy Coal Plant Derate/Outage Incidents 2010-2014



2014 Focused on IPH Reliability
- Preventative maintenance at all sites
- EFOR Improvement initiative at IPH
- Achieved 340 bps Equivalent Availability Factor improvement

2015 Performance Improvement Program Underway
- Reliability and heat rate team formed
- Initial focus on coal-fired boiler tube leaks
- Prioritize spend to best opportunities
- Improved maintenance and operations activities

Boiler Reliability Improvement
- Boiler tube failure is the most common reason for forced outages
  - 3x the level of the next largest single contributor
- Approximately $44 MM (2.8 MM MWh) in lost margin opportunity in 2014 due to boiler tube failures
- Targeting top decile Equivalent Availability Factor (~90%) by 2019

Reliability is increasingly valuable as energy and capacity markets reward plant performance

Environmental Compliance Strategy

Air Regulations Compliance
- Focus over the past several years has been on implementing compliance strategies for state and federal rules[1]
- Fleet compliant with MATS, CSAPR, consent decrees and other known state and federal rules

Turning Toward Water and CCR Rules
- Focus shifts to compliance with new federal 316(b), ELG, and CCR rules for water outfalls and coal combustion residuals
- 316(b) rule signed in April 2014
- Effluent Limit Guidelines (ELG) rule expected September 30, 2015
- Coal Combustion Residual (CCR) rule published in April 2015

Compliant with current air regulations; focusing on cost-effective compliance with 316(b), ELG, and CCR rules

[1] See appendix for plant-by-plant environmental controls

CCR Compliance Timeline

Final Rule Published - April 17, 2015

Date	Compliance Requirements	Year	Dynegy Actions
Oct–Dec 2015	• Initiate site inspections • Implement dust control plan • Launch public internet site • Provide notification of site closure intent	2015	✓ Training internal Dynegy inspection personnel scheduled 3Q15 ✓ Dust control plans under development ✓ Reviewing 3rd party vendors for creation of public internet site ✓ Initial site classifications complete; decisions forthcoming
Jan 2016	Complete initial PE-certified annual inspection	2016	✓ Consultant under contract to complete required inspection
Oct 2016	Complete site history and safety factor assessment		✓ Site assessments underway for structural integrity and location restrictions – No Issues: Site remains open – Issues: Remediate or start closure within 6 months
Apr 2017	Complete initial Emergency Action Plans	2017	✓ Compiling emergency action plans and O&M manuals for review and update
Oct 2017	Complete well installments and 8 sampling events		✓ Analysis and well installation is underway – No issues: Sites remain open – Issues: Two 90-day confirmation phases and then remain open or remediate, or close within 6 months
Apr 2018	Deadline for final closure of inactive ponds that are exempt from post closure requirements	2018	✓ Evaluation of inactive ponds underway
Oct 2018	Demonstrate compliance with location restrictions		✓ Location restrictions certification – No Issues: Site remains open – Issues: Remediate or start closure within 6 months

Action plan in place and on track to comply with all CCR rule requirements

316(b) Compliance Strategy and Timeline

~$5 MM (2016–2018) ~$55 MM (2019–2022)

Affected Plant	2015	2016	2017	2018	2019	2020	2021	2022
Baldwin					NPDES Renewal		316(b) Compliance	
Hennepin		NPDES Renewal		316(b) Compliance				
Wood River						NPDES Renewal		316(b) Compliance
Stuart 1-3[1]				NPDES Renewal		316(b) Compliance		
Edwards						NPDES Renewal		316(b) Compliance
Joppa						NPDES Renewal		316(b) Compliance
Newton					NPDES Renewal		316(b) Compliance	
Coffeen					NPDES Renewal		316(b) Compliance	
Kincaid						NPDES Renewal		316(b) Compliance

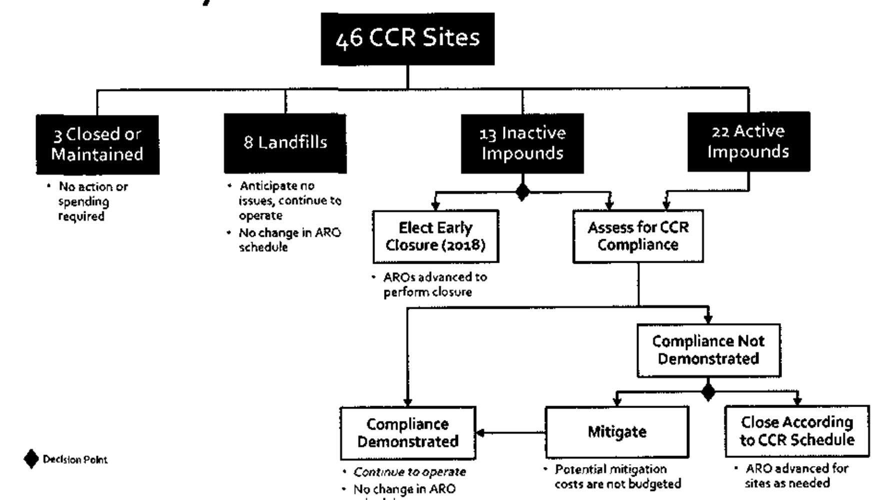
Compliance Profile
- Most of the recently acquired assets have cooling towers
- Aquatic impingement and entrainment studies to be performed prior to NPDES renewal
- Compliance expected within 24 months after NPDES permit is renewed

Investment Profile
- Majority of sites require little to no capital spending
- Variable speed drives to be installed at Moss Landing by end of 2016 with full compliance by 2020 under settlement with California State Water Resources Board

Majority of ~$60 MM compliance spend will occur in 2020-2022

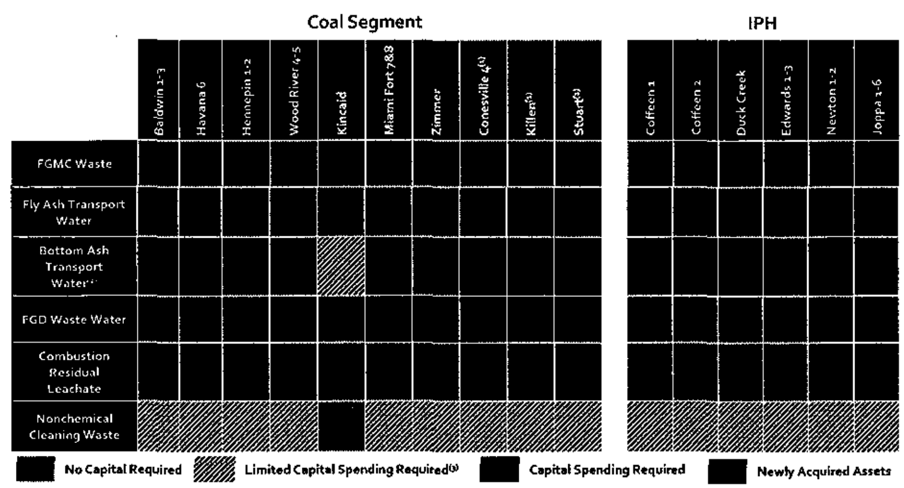
[1] Facility is partially owned but not operated by Dynegy

Preliminary CCR Site Assessment



CCR Site Assessment in progress that will guide future decision-making

ELG Compliance Assumptions – Spend Profile



Expected compliance requirements vary according to plant design; most of ~$290 MM spend anticipated in 2018-2023

Note: See appendix for schedule of NPDES water permit renewals and ELG compliance dates; Brayton Point is fully compliant with federal environmental regulations until its scheduled retirement in June 2017
[1] Facility is partially owned but not operated by Dynegy; [2] Units <400 MW exempt from Bottom Ash Transport Water Requirement; [3] Less than $2 MM in total per plant

Summary and Estimated Compliance Spend

316(b)
- Spending expectations from last year largely unchanged
- Acquired plants largely compliant
- Cost estimates for acquired plants have increased total spending estimate by ~$10 MM
- Majority of spending in 2020-2022

ELG
- Cost estimates based on current expectations for final rule
- Cost estimates for acquired coal plants have increased total spending estimate by ~$150 MM
- Majority of spending expected in 2018-2023

CCR
- Final rule is manageable and in line with expectation
- Anticipated spending will be adjusted as site analyses are completed

Expected Cash Compliance Cost for Major Environmental Rules[1][2] ($ MM)

	2015	2016	2017	2018	Dynegy Ex. IPH 2019-2023	IPH 2019-2023
316(b)	-	-	~2	~3	~20	~35
ELG	-	~1	~4	~35	~185	~65
CCR	-	~3	~13	~47	~165	~130
Total	-	~4	~19	~85	~370	~230

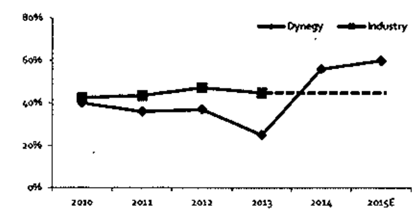
- Bulk of spending in 2019 and 2020
- Peak year spending in 2019 of ~$195 MM for the combined compliance program

Environmental spending requirement expected to be manageable

[1] See Appendix for additional details; [2] Includes non-operated JOUs

Coal Combustion Byproduct Re-use

Dynegy CCB Beneficial Re-use vs. Industry[1][2]



2014 Dynegy CCB Re-use by Category[2]

Tons	Produced	Reused	Percentage
Fly Ash	1,519,051	757,677	50%
Bottom Ash	795,004	342,988	43%
Gypsum	1,064,673	880,486	83%
SDA	142,356	0	0%
Total	3,521,084	1,981,151	56%

Beneficial Re-use of CCBs Set to Grow
- EPA did not classify CCBs as Hazardous Waste
- Non-Hazardous classification enables the recycling of coal ash for manufacturing products such as Portland cement and gypsum wallboard
- With regulatory certainty, the beneficial use of CCBs is set to grow

Creating Carbon Offsets
- CCB strategy team formed in 2015 to improve marketing and product development
- Ohio coal plants have established channels to reuse high percentage of CCB production
- Third party to build fly ash milling facility at Duck Creek Station in 2016
- Displaces significant carbon emissions from cement production

Targeting 100% beneficial re-use by 2020

[1] Industry statistics from American Coal Ash Association; 2013 is most recent available data; [2] Amounts are pro-forma for a full year of ownership of the Ohio coal plants, Kincaid, and Brayton Point starting in 2014, excluding non-operated joint owned units; prior years are for the legacy Dynegy fleet

Operations Support Summary

- Active response to 316(b), ELG, and CCR rules underway
- Environmental spending expected to be manageable and limited in the near-term
- Cost and timing of CCR compliance will be refined as analysis progresses
- Solid progress toward 2020 goal of 100% CCR beneficial re-use

DYNEGY

Retail

Sheree Petrone
EVP, Retail

Retail Priorities

Risk Reduction	• Operate only in markets where Dynegy has generating assets • Ensure sufficient excess generation to manage load following risk • Retail sales strategies aligned with Dynegy's commercial objectives to hedge generation
EBITDA Contribution	• Generate incremental earnings by building profitable Retail positions in the markets served • Operate within a flexible lower-cost infrastructure comprised of high-performing processes, people, and systems
Customer Focus	• Create value for customers • Leverage insight into customer priorities to inform Dynegy strategies • Target customers that offer large amounts of load and are cost-efficient to serve

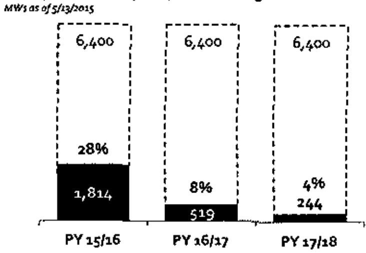
Dynegy's Retail business provides a channel to market for generation, contributes incremental earnings, and creates value for customers

DYNEGY

Retail as a Risk Reduction Tool

Key Channel to Market for MISO Capacity

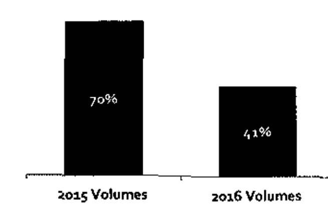
Dynegy's MISO Capacity Sold Through Retail
MWs as of 5/13/2015



- 28% of MISO capacity was sold through the Retail channel in Planning Year 2015/2016
- Because of 18 month tenor of book, expect future year capacity sales to increase as accounts renew

Cost-Effective Hedge for IPH

IPH Energy Hedged Through Retail Sales
Percent as of 5/13/2015



- Retail provides a cost-efficient hedge for the wholesale business
  - Avoids third-party credit charges
  - Saves bid/ask spread
  - Reduces collateral needs
- *For IPH, the Retail business is the only available hedging mechanism due to collateral limitations*

The retail and wholesale businesses serve as cost-efficient hedges for one another, *saving $20-25 MM annually versus hedging in the market*

DYNEGY

Dynegy's MISO Retail Business

MISO (Southern Illinois)

Brand

HOMEFIELD ENERGY A DYNEGY COMPANY

Customers

- 10,700 GWh of load served in 2014
- 11,300 C&I accounts
- *473,000 Residential accounts served through Municipal Aggregation deals*

Market Share

2014 MISO-Illinois Market (GWh)[1] — **2018E MISO-Illinois Market** (GWh)[1]

2014 Market Size: ~37,000 GWh

Consolidation and competitors exiting the southern Illinois market provide opportunity for Dynegy to grow market share

(1) Based on utility switching statistics, MISO load data, and internal analysis

DYNEGY

Dynegy's PJM Retail Business

PJM (Ohio, Northern Illinois)[1]

Brand

DYNEGY ENERGY SERVICES

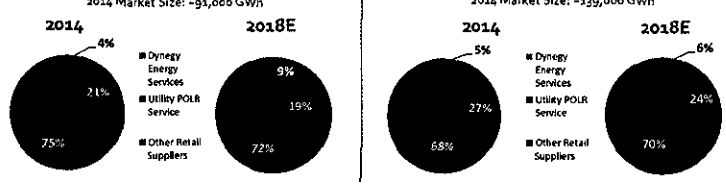
Customers

PJM-ILLINOIS	PJM-OHIO
• 5,800 C&I accounts • 300,000 Residential accounts (Muni Agg) • 4,000 GWh of load served in 2014	• 13,100 C&I accounts • 122,000 Residential accounts • 7,100 GWh of load served in 2014

Market Share

PJM-Illinois Market (GWh)[2]
2014 Market Size: ~91,000 GWh

PJM-Ohio Market (GWh)[2]
2014 Market Size: ~139,000 GWh



Relatively small player in Ohio and northern Illinois, *but positioned to increase sales volume in PJM*

(1) Dynegy Energy Services totals include Duke and PJM-Illinois accounts currently served by Homefield Energy, these accounts will transfer to Dynegy Energy Services with renewal
(2) Based on utility switching statistics, PJM load data, and internal analysis

DYNEGY

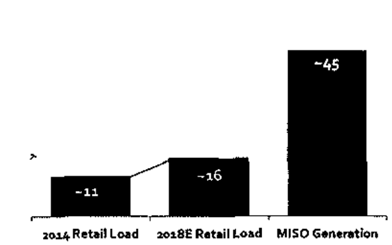
Customer Acquisition Strategy

	Commercial & Industrial	Residential
Share of Dynegy Retail Volumes	~60%	~40%
Target Customers	• Large commercial and industrial accounts (>5 MW)	• Municipal Aggregation accounts, which are aggregated residential communities (up to 1,000 MW)
Acquisition	• Small direct sales force • Develop and leverage relationships with energy consultants and brokers to capture load	• Energy consultants for Muni Agg accounts • Email marketing and digital enrollment • Affinity programs
Offering	• Expertise in wholesale markets • Increasing brand awareness	• Local community presence • Cost competitive
Service	• Integrated, single operations infrastructure reduces costs	• Utility handles credit collection and billing for Muni Agg and residential customers • Outsourced call center

We focus on accounts with large volumes of load that reduce the cost to acquire and serve versus conventional retail providers

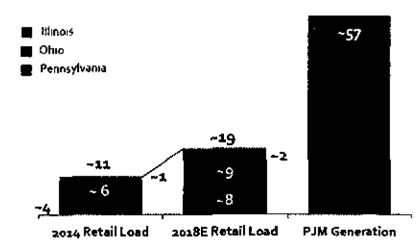
Growing Market Share in Existing Markets

Dynegy MISO Illinois Retail Load vs. Generation Length



Competitors Exiting Southern Illinois Creates Opportunity
- Established retailers are exiting the market following the Polar Vortex
- Generation-backed retailers have strong competitive advantage

Dynegy PJM Retail Load vs. Generation Length[1]



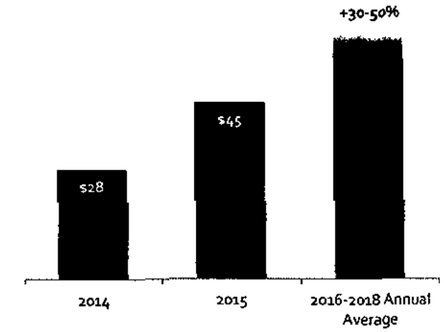
High Level of Commitment to Ohio Market
- Positioned to be competitive and grow market share
- Others may be re-evaluating retail business priorities

Significant generation length is available to expand retail market share

[1] Includes only markets in which Dynegy has generation – Northern Illinois, Pennsylvania, and Ohio

Gross Margin

Retail Adjusted Gross Margin[1] ($ MM)



Volume Growth with Stable Unit Margins
- Goal of increasing market share, particularly in Illinois (both MISO and PJM)
- Drives increase in volume and gross margin through 2018
- Unit margins during the period are, on average, relatively stable

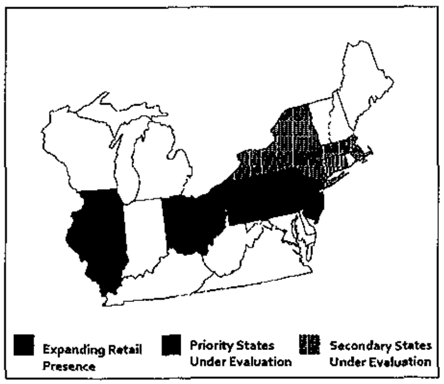
Pricing Trends and Customer Mix
- Polar Vortex pricing benefits 2015-2016 unit margins
  - Following the Polar Vortex in 1Q14, we were able to capture price premiums and win additional Muni Agg load, in some cases with longer-dated contracts, benefitting 2015-2016 margins
- Unit margins normalize over time
  - Large commercial and industrial accounts with lower margins are expected to grow at a faster rate than other segments, muting the impact of the margin expansion that followed Polar Vortex

Volume growth offsets a return to more normal pricing levels

[1] Retail Adjusted Gross Margin is net of energy purchases, bad debt expense, and incremental operating costs; excludes one-time credits and value of ARR benefits from MISO

Evaluating Expansion to New States

Retail Presence and Potential Expansion



Market Evaluation Criteria

✓	Significant Generation Length to back Retail Sales
✓	Legislative Support for Retail Competition
✓	Competitive Landscape
✓	Muni Agg Opt-Out for Residential Customers
✓	Utility-provided Billing and Collections for Residential Customers
✓	No Fuel Delivery Constraints
✓	Infrastructure in Place for Load Following

Taking a disciplined approach to new markets where we have generation

Profound Industry Change with Lasting Impact

Wave 1			Wave 2
Generation Mix Shift	**System Instability**	**Regulatory Response**	**Additional Asset Retirements**
Baseload Retirements • ~50 GW of generation exits Dynegy's key markets as a result of environmental and economic factors **Replaced with Less Reliable Intermittent Resources** • Renewables new build remains strong • Demand response increasing part of *generation mix*	**Tightening Capacity Markets** • ISO-NE clears near CONE • MISO capacity auction may clear at CONE **Volatile Power Prices** • More volatile energy prices as reserve margins tighten **Reliability Concerns** • Poor system performance during Polar Vortex	**Move to Prioritize Quality** • ISO-NE Performance Incentive rules • PJM Capacity Performance Product **Future of Demand Response Uncertain** • Demand Response held to same standards as generators	**Older, Less Reliable Assets at Risk of Retirement** • Performance penalties challenge economics of unreliable assets **New Build Challenged** • New CCGTs enter market, but delayed by permitting, siting, and financing challenges • Performance penalties complicate economics

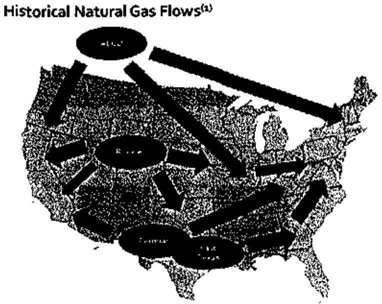
Profound industry change following the first wave of retirements; a second wave is coming as markets shift to penalize poor performance

Retail Summary

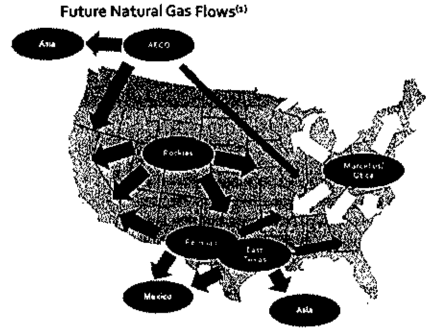
- Retail remains an attractive channel to market and an efficient hedging mechanism for our generation assets
- Shifts in the competitive landscape provide opportunity to gain market share
- Expect growth in gross margin and EBITDA contributions driven primarily by volume growth
- A disciplined approach to potential expansion

Changing Natural Gas Market Dynamics

Historical Natural Gas Flows[1]

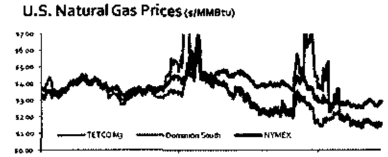


Future Natural Gas Flows[1]



U.S. Natural Gas Consumption by Sector[2] (Bcfd)

U.S. Natural Gas Prices ($/MMBtu)



Shifting natural gas market dynamics pressuring coal and nuclear plant economics, intensifying industry changes

[1] Morgan Stanley, [2] EIA

DYNEGY

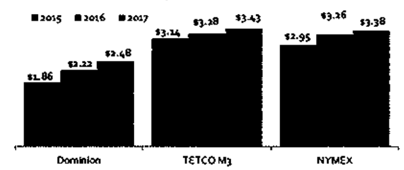
Commercial

Hank Jones
Chief Commercial Officer

Dynegy's Fuel Cost Advantage

Cost-Competitive Natural Gas	Cost-Competitive Coal

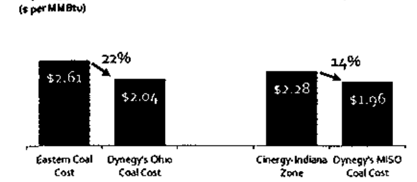
Natural Gas Price(1) ($ per MMbtu)



AD Hub(2)	PJM W
~3.5 GW	~1.2 GW
60% of PJM CCGT Fleet	20% of PJM CCGT Fleet

Locational Advantage Drives Low Natural Gas Cost
- ~2.5 GW of efficient CCGT capacity located along interstate pipelines in the Marcellus and Utica
- ~1.1 GW of efficient CCGT in NYISO sources gas from the Marcellus and benefits from a similar fuel cost advantage

Dynegy 2014 Delivered Coal Prices versus Competitors(3) ($ per MMBtu)



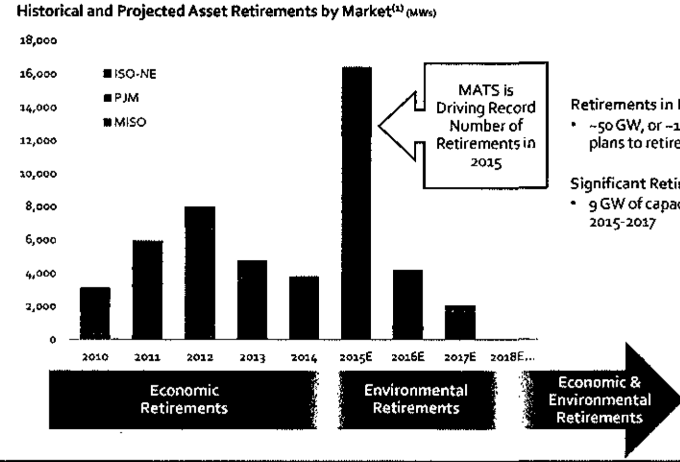
Coal Plants Have Fuel Cost Advantage
- Dynegy's fuel cost advantage represents ~$6 per MWh in PJM and ~$3 per MWh in MISO
- Active blending of Illinois Basin coal at the PJM fleet reduces fuel cost versus Appalachian coal plants
- Testing underway to determine ability to increase use of Illinois Basin coal at the Ohio coal fleet
- Refined coal contributes over $1 per ton toward reducing coal costs

Unrivaled access to low-cost fuel

 (1) As of 5/13/2015; (2) Includes Independence; although not at AD Hub, Independence prices gas off of Dominion South; (3) Ventyx, Eastern region includes ACE, BGE, DPL, PENELEC, PEPCO, PPL, and PSEG zones

First Wave of Retirements
Baseload Generation Leaves the Market

Historical and Projected Asset Retirements by Market(1) (MWs)



Retirements in Dynegy's Key Markets
- ~50 GW, or ~15%, of capacity has retired, or plans to retire, in ISO-NE, PJM, and MISO

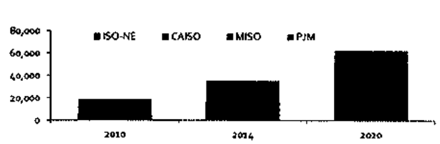
Significant Retirements in Adjacent Markets
- 9 GW of capacity retiring in SERC and SPP in 2015-2017

15% of the installed capacity leaving the system across three major US power markets

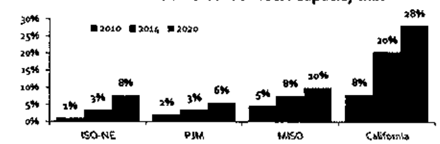
 (1) Ventyx

Replacement Capacity
Non-Dispatchable Renewables

Cumulative Wind and Solar Capacity Additions(1) (in MW)

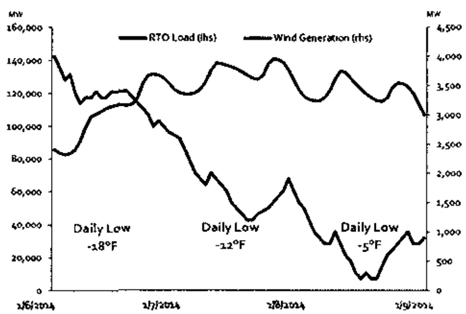


Wind and Solar as a Percent of Total Capacity Mix(1)



Retirements Replaced by Non-Dispatchable Assets
- Renewable capacity is primarily wind and solar
- Low capacity factors and non-dispatchable nature make renewable resources a poor replacement for retiring coal and nuclear plants

Wind Generation During Winter Peak(2)



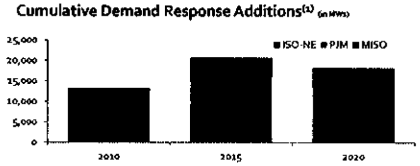
Intermittent Resources Physically Stress the System
- Intermittent resources are not always generating electricity when it is needed
- Mismatch of intermittent generation and load stresses the system

Replacing dispatchable plants with intermittent renewables places significant stress on the system

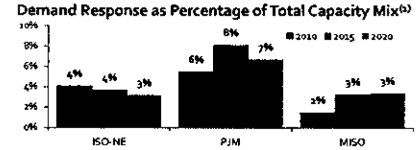
 (1) Ventyx, reflects nameplate capacity additions; (2) PJM, low temperature reflects daily low for Columbus, Chicago, Philadelphia, and Richmond

Replacement Capacity
Unreliable Demand Response

Cumulative Demand Response Additions(1) (in MWs)

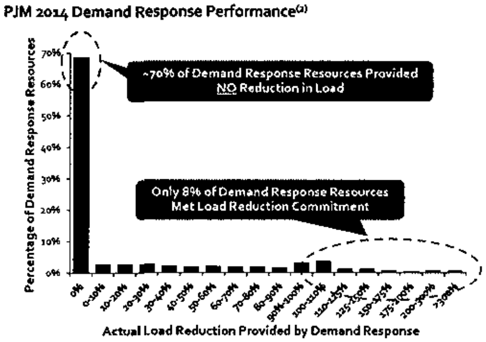


Demand Response as Percentage of Total Capacity Mix(1)



Retirements Replaced by Unreliable Assets
- Demand response comprises a significant portion of the capacity across Dynegy's key markets

PJM 2014 Demand Response Performance(2)



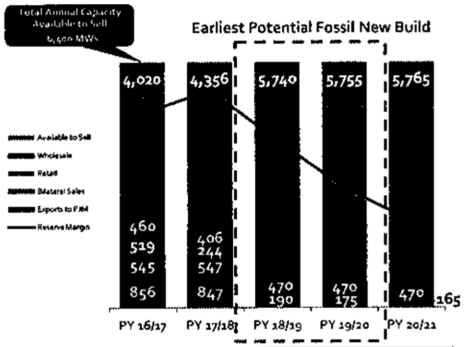
Reduced Market Participation by Demand Response Drives Capacity Prices Higher
- Independent Market Monitor projects that Demand Response participation in capacity markets depresses capacity market clearing prices by 25-30%

Reduced Demand Response participation further tightens markets

 (1) ICF, NERC, Dynegy Strategic Market Analysis; (2) PJM 2014 State of the Market Report

Dynegy's MISO Capacity

MISO Classic Reserve Margin and Dynegy Capacity Sales[1]



	PY 16/17	PY 17/18	PY 18/19	PY 19/20	PY 20/21
Volume Sold	37%	32%	10%	10%	10%
Average Price ($/kw-month)	$2.69	$3.65	$4.96	$4.79	$4.84
EBITDA Contribution ($MM)	$77	$90	$39	$37	$37

Channels to Market for Dynegy's Capacity

Exports to PJM
- Expect ~850 MW of exports to PJM to clear upcoming PJM capacity auctions
- 240 MWs of exports to PJM pending for Planning Year 2017/2018
- Exports to PJM qualify for PJM Capacity Performance

Retail
- Average Retail contract tenor of 18 months
- Capacity sales expected to build as the Retail portfolio renews

Bilateral Sales and Wholesale Origination
- Over 80 Muni's and COOP's in MISO create multiple opportunities to sell capacity

Annual Capacity Auction
- We view the annual MISO capacity auction as a market of last resort for capacity sales

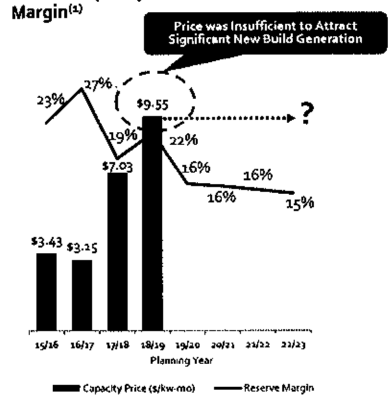
Almost 80% of our capacity in MISO remains available to sell

71 (1) Dynegy Strategic Market Analysis, reflects MISO Classic, Dynegy capacity position as of 6/12/2015

DYNEGY

Retiring Dispatchable Assets has Consequences
New England Capacity Market

ISO-NE Capacity Auction Results and Reserve Margin[1]



New England Capacity Shortfall Projected to Persist
- 5 GW, or ~15%, of dependable assets have exited or are pending retirement in New England
- PY 18/19 auction cleared at $9.55 per kw-month with a 22% reserve margin
- ISO-NE projects reserve margins of 15-16% through PY 22/23

Incremental Assets at Risk
- 5 GW of older, oil-fired units remain at risk

Northern Pass Alone Will Not Solve the Problem
- ISO-NE proposing a Northern Capacity Zone
- The Northern Capacity Zone would likely separate and clear at a low capacity price with the addition of Northern Pass
- Would trap Northern Pass imports in the proposed Northern Zone, which is exports-constrained
- ~80% of Dynegy's capacity is in Southern New England[2]

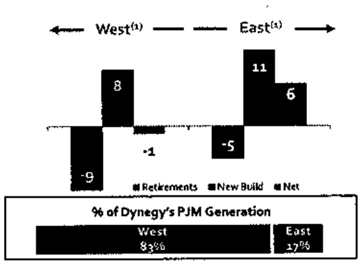
New England reserve margins tightening further

69 (1) Source: ISO-NE; (2) Excludes Brayton Point

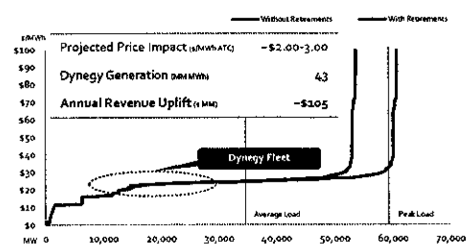
DYNEGY

First Wave of Retirements Results in Higher Prices
PJM – Retirements in the West; New Build in the East

PJM Retirements and New Build 2015-2018 (GWs)



AD Hub Dispatch Stack[2]



Retirements Concentrated in Western PJM
- The bulk of asset retirements are concentrated in Western PJM where limited new capacity is being built
- Western PJM prices are expected to rise to parity with Eastern PJM over time as transmission infrastructure is developed

New Build Concentrated in Eastern PJM
- New entry being sited in Eastern PJM in order to be close to load centers
- Growing proximity to inexpensive natural gas as Marcellus and Utica supply migrates East

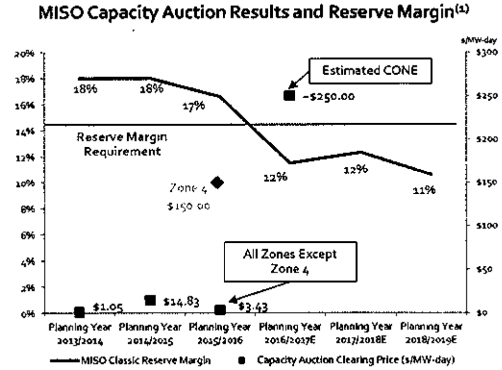
Tightening supply in Western PJM benefits Dynegy as power prices increase

72 (1) West reflects RTO, East reflects MAAC; (2) Ventyx and Dynegy Fundamentals; reflects net retirements through 2017

DYNEGY

Retiring Dispatchable Assets has Consequences
MISO Capacity Auction

MISO Capacity Auction Results and Reserve Margin[1]



Dependable Assets Leaving the MISO Market
- The brunt of MATS-driven retirements affect the MISO capacity market in Planning Year 2015/2016
- 14 GW, or ~15%, of dispatchable installed capacity leaving the market by April 2016
- Minimal dispatachable generation in the development queue

Reserve Margin Shortfall Not Fixed by New Build Until 2018/2019 at the Earliest
- Over 3 GWs of capacity shortfall projected in MISO Classic for Planning Year 2016/2017

Vertical Demand Curve in MISO Market Design
- Capacity is of little or no value when the system has any excess capacity
- Capacity is extremely valuable when the system is short
- The MISO tariff prices capacity at CONE, or ~$250 per MW-day for Planning Year 2016/2017, if the system is short

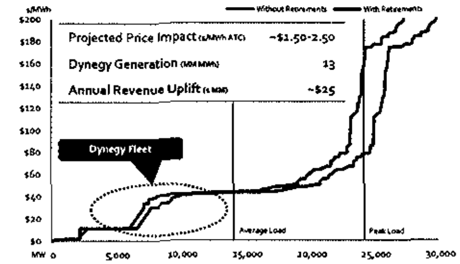
Lack of new resources could result in the annual capacity auction clearing at CONE

70 (1) Dynegy Strategic Market Analysis, reflects average Planning Year clearing prices across MISO zones unless otherwise noted

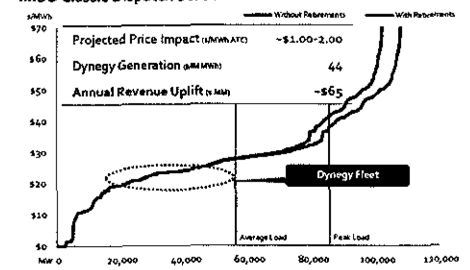
DYNEGY

First Wave of Retirements Results in Higher Prices
ISO-NE and MISO

ISO-NE Dispatch Stack[1]



MISO Classic Dispatch Stack[1]



Low-Cost Assets Exiting The Market
- Retiring assets generally have low marginal costs

Expensive Replacement Energy
- Replacement energy must come from the next available plant with excess generating capacity
- Plants making up the shortfall typically have higher marginal costs

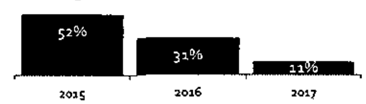
Understated Value of Volatility
- Expect increased periods of volatile, expensive energy prices
- Average price analysis does a poor job of capturing volatility, and thus understates the potential upside

Tightening supply in ISO-NE and MISO benefits Dynegy as power prices increase

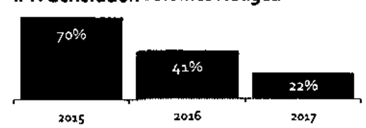
[1] Ventyx and Dynegy Fundamentals; reflects net retirements through 2017

Dynegy's Hedging Strategy
Protect Margins While Retaining Upside

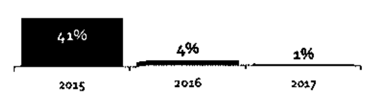
Coal Segment Generation Volumes Hedged[1]



IPH Generation Volumes Hedged[1]



Gas Segment Generation Volumes Hedged[1]



Hedging to Protect Dark Spread and Retain Spark Spread Upside
- Coal Segment and IPH hedges protect the dark spread while still retaining exposure to rising power prices
- Gas Segment less hedged to position the fleet to benefit from expanding spark spreads

Hedge Levels Increase as Prompt Year Approaches
- Forward hedge percentages will increase as prompt year approaches
- Forward hedges at IPH increase as Retail book renews
  - Average Retail contract tenor of 18 months

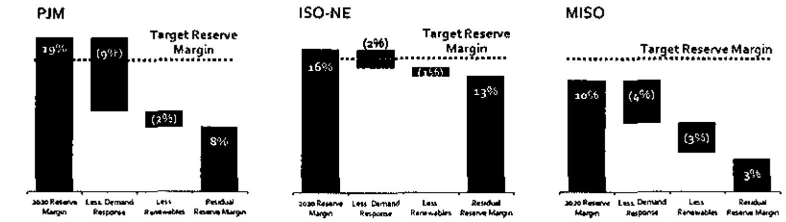
Market View Drives Balance of Hedging Decisions
- The balance of the portfolio is open and reflects our market view that structural changes will lead to higher prices

Positioned to benefit from the rise in energy prices expected to result from structural changes in the industry

[1] As of 5/13/2015; reflects combined fleet

ISO's Recognizing Perils of Shifting Generation Mix
Developing Performance Penalty Market Design in Response

Demand Response and Renewables in Reserve Margin by Market[1]



Heavy Reliance on Intermittent Resources and Demand Response
- PJM is below its target reserve margin excluding Demand Response and renewables
- ISO-NE is below its target reserve margin excluding Demand Response
- MISO is below its target reserve margin even with Demand Response and renewables

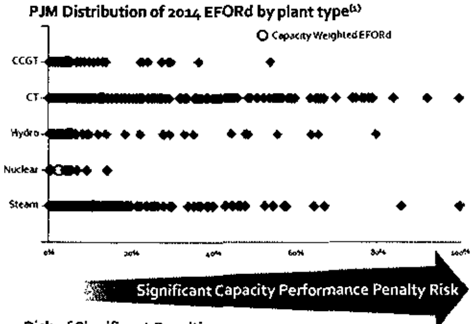
Adoption of Performance Penalties to Recognize Asset Quality
- PJM and ISO-NE market design evolving to differentiate between capacity whereas previously, all capacity was compensated equally
- Capacity must perform in order to be compensated
- Demand Response and renewables challenged in markets that reward reliability and penalize poor performance

Capacity performance requirements in PJM and ISO-NE will hold assets to a higher standard

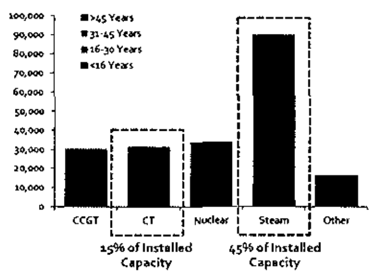
[1] MISO, ISO-NE, PJM, ICF, NERC, Dynegy Strategic Market Analysis

Second Wave of Retirements
Performance Requirements Put Additional Assets at Risk

PJM Distribution of 2014 EFORd by plant type[1]



PJM Capacity by Technology and Age[1] (MWs)



Risk of Significant Penalties
- Poor operating performance puts assets at risk of incurring material penalties under PJM Capacity Performance

Revenue at Risk
- Units with poor reliability currently rely on the capacity market for the bulk of their revenue, but may not clear the auction under Capacity Performance

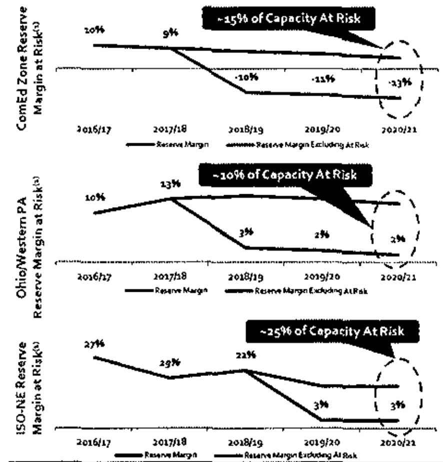
Significant Capacity with Material Operating Risk
- Steam and CT units comprise ~60% of PJM capacity
- Vast majority of Steam units are over 30 years old
- Difficult to justify reliability investment in aging assets

Assets with poor reliability will struggle to survive in markets with performance penalties

[1] PJM 2014 State of the Market Report

Second Wave of Retirements

Potential for Further Reserve Margin Contraction



Zonal Resources Critical in PJM
- ComEd and Ohio/Western Pennsylvania are key markets for Dynegy
- Tight zonal Capacity Performance resources could cause zones to separate and price higher than adjacent zones

Significant Penalties for Poor Performance
- Non-performance penalty of $3,897 per MWh in PJM
  - 8 hour outage represents $85 per MW-day
- *Non-performance penalty of $2,000 per MWh in ISO-NE, rising to $5,450 per MWh in future years*

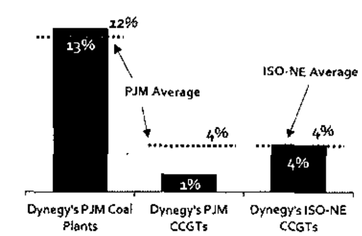
Performance Risk Likely Drives Additional Assets Out of the Market
- CTs rely on capacity revenues, but CTs have high EFORd
- Coal-to-gas conversions likely face performance risk
- Older units, especially oil-fired capacity, likely face performance risk
- Air permits required for dual fuel capability difficult to obtain

Performance penalties place additional stress on unreliable plants, driving capacity out of the market and capacity prices higher

[1] Ventyx, Dynegy Strategic Market Analysis

PJM Capacity Performance Benefits Dynegy

Dynegy's PJM and ISO-NE Coal Plant and CCGT EFORd Rates[1][2]



Dynegy Positioned to Benefit from Capacity Performance
- Dynegy fleet of over 60 units diversifies performance risk
- Reliability initiatives underway to improve EFORd at the recently acquired plants
- Access to diverse fuel supply with multiple delivery points

At Risk Assets Could Bid High Under Capacity Performance
- Generators with poor reliability can reflect the risk they face in a Capacity Performance market by increasing their bids, driving Capacity Performance prices higher

At Risk Assets Could Prolong Structural Changes in the Market
- Alternatively, generators with poor reliability can carry the risk of performance penalties, but penalties likely ultimately force higher offer prices or results in the assets exiting the market
  - Generators with poor performance who accept performance risk will not know the prudence of their decision until 2018
  - If penalties force generators out of the market, replacement capacity would be not be available until several years later

Dynegy's fleet reliability is on par with or better than PJM and ISO-NE average plant reliability; less reliable assets could be economically challenged

[1] PJM 2014 State of the Market Report, ISO-NE, [2] Dynegy's PJM Coal Plant EFORd excludes the Zimmer coal plant, Zimmer 2014 EFORd driven by lack of natural gas for startup fuel; process to re-commission dual fuel startup capability underway

New Entry Faces Hurdles Across Markets

ISO-NE	New Entry Assets in ISO-NE Face Significant Economic and Siting Hurdles • Only 1,000 MWs of new entry cleared the recent capacity auction despite opportunity to lock-in a $9.55 per kw-month capacity price for seven years • Northern Pass project initial spending in second half of 2009; current target in service date of 2019, but numerous regulatory approvals remain outstanding
PJM	High Financial Hurdles For New Build Under Capacity Performance • Historically, PJM has added only ~2.5 GW of new capacity per year • Only ~20% of announced new entry actually built • Insufficient market liquidity to lock-in high spark spreads long term affects ability to finance new projects • Financing new build likely difficult under Capacity Performance product given the significant risk of penalties and potential for negative cash flow • Five-fold increase in collateral requirements for new build under Capacity Performance increases the cost of new entry[1]
MISO	Less than 4 GW (~2%) of Planned New Entry has Generation Interconnect; Only 1 GW Under Construction • Limited forward capacity price signal as March capacity auction sets prices that take effect in June for one year • Regulated utilities can elect to build, but projects have long lead-times

New entry faces economic and siting challenges across Dynegy's key markets; prolongs the impact of tight reserve margins on the market

[1] Collateral requirement increases to 0.5 x Net CONE from 0.2 x BRA clearing price; increase shown is relative to $120 per MW-day RTO clearing price

Dynegy's Capacity Additions

Low Cost with Speed to Market

Status	Market	Total MW	Total Cost ($/kW)	Technology
In Service				
	PJM	40	[1]	Baseload
	EEI[2]	235	~$5	Peaking
Development Underway				
	PJM	260	~$200-250	Baseload
	ISO-NE	100	~$325-400	Baseload
	NYISO	50	[1]	Baseload
Total		685		
Under Evaluation				
	PJM	~750	Discount to Greenfield	Baseload

Significant Value Creation Through Capacity Additions
- Expansions and uprates have high double-digit IRRs
- 235 MW CT addition in EEI at less than $5 per kW online July 1, 2015
  - EEI can sell into TVA, KU, or MISO
- Competitive advantage from speed to market, with the bulk (~80%) of expansions and uprates online in 2016
- *Development underway in New England is expected to be eligible to lock-in the market clearing capacity price for seven years*

Potential Low-Cost Brownfield Development
- Economic evaluation underway for a ~750 MW CCGT
- Fully-permitted site acquired adjacent to Ontelaunee
- On-site access to interstate gas pipeline
- Co-location with Ontelaunee captures advantages of a brownfield development and provides ongoing competitive operating cost advantage for both assets

Adding the equivalent of almost a new CCGT to the fleet through expansions and uprates at a fraction of the cost and time to market of new entry

[1] Price is confidential, [2] EEI can sell into TVA, KU, or MISO

Commercial Summary

	Market Dynamics	How Dynegy Wins
1	Tightening Reserve Margins Persist; Quality of Assets Matters	Reliable large-scale portfolio in key capacity markets
2	Increasing Energy Prices	High capacity factors with relatively open hedge profile
3	Plentiful Marcellus Shale Gas	CCGT fleet with price-advantaged access to natural gas coupled with low-cost coal portfolio
4	New Build Faces Hurdles	Speed to market with low-cost capacity uprates at high IRRs

Dynegy is well-positioned to capture the upside from shifting market dynamics

DYNEGY

DYNEGY

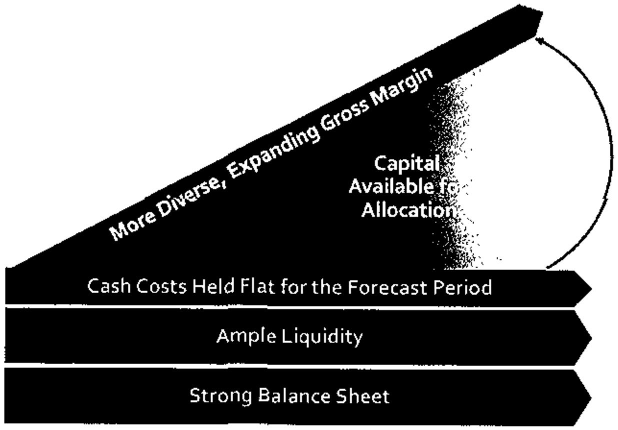
Financial

Clint Freeland

CFO

Zimmer Power Station

Financial Overview



Growth in Gross Margin results in additional discretionary capital available for allocation

Capital Allocation anchored by stable foundation of cost control, ample liquidity, and strong balance sheet

Strong balance sheet and ample liquidity set the foundation for allocating capital from more diverse, expanding gross margin

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Capital Allocation

Capital Allocation Strategy

Balance Sheet Management	Intrinsic Investment	M&A	Return to Shareholders
• Right-sized balance sheet in place today • Modest debt reduction and/or EBITDA improvement migrates credit metrics toward BB	• Plant expansions/uprates • Plant performance improvement – Accelerated outages • Transmission • Brownfield development	• Significant presence in three of the best power markets in the US • Monitor the market for attractive opportunities that may emerge	• Open market share repurchases preferred • Common dividends unlikely in foreseeable future • ~$2,000 MM of restricted payments capacity at the end of 1Q15
Migrating toward BB metrics over time	Compelling investments in various stages of development	M&A opportunity must expand presence in current markets or be sufficiently compelling to dilute current market mix	Benchmark against which other uses of capital compete

All capital allocation decisions are benchmarked against share repurchases

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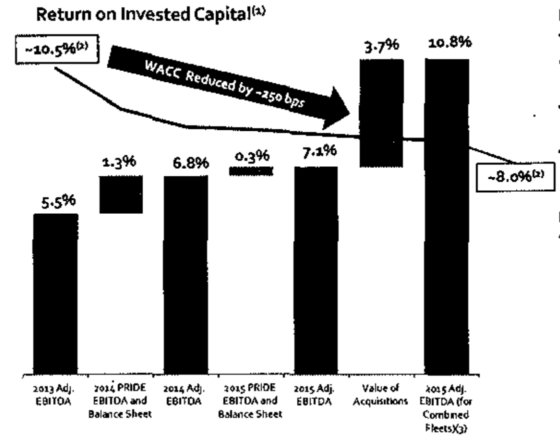
Improving ROIC and Driving Down Cost of Capital



Improving Return on Invested Capital
- ROIC used to gauge performance improvement
- Significant ROIC improvement from internal PRIDE initiatives
- Substantial benefit to ROIC from Duke Midwest generation and EquiPower acquisitions
- Upside potential as a result of structural changes affecting the power markets

Reducing the Weighted Average Cost of Capital
- Lowered the cost of debt by over 300 bps

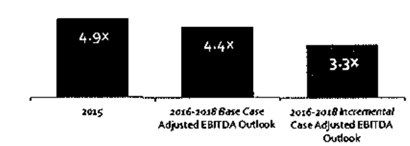
ROIC Sensitivities	
+$100 MM PRIDE EBITDA	0.9%
+$1 per MMBtu natural gas	*1.7%*

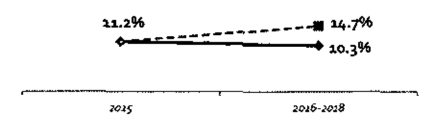
Doubled ROIC while driving down the cost of capital by ~250 bps

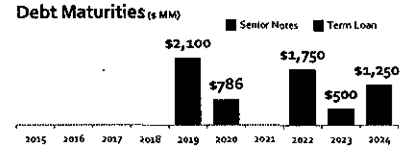
[1] Excludes IPH, Adjusted EBITDA is a non-GAAP measure; [2] CAPM calculation; cost of debt is not tax-adjusted given NOL position, [3] Sum of [a]Midpoint of 2015 Adjusted EBITDA guidance as presented on May 6, 2015 and [b]1Q15 Adjusted EBITDA not realized due to delayed acquisition closing

 DYNEGY

Dynegy Inc. Credit Profile(1)







Strong Balance Sheet Provides Financial Flexibility
- Staggered maturities with no near-term obligations
- *Primarily unsecured financing* with flexible covenants facilitates optimal capital management

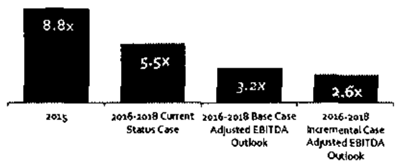
Significant Internal Balance Sheet and Liquidity Improvement
- PRIDE has contributed $880 MM of improvement since 2011
- Transaction synergies contributing $375 MM of improvement

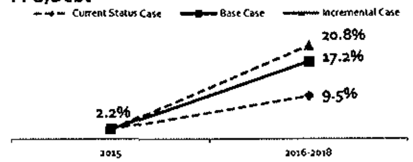
Modest debt reduction and/or EBITDA improvement migrates credit metrics to BB target over time

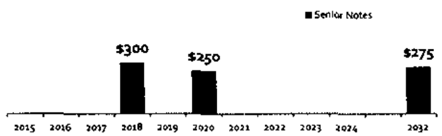
[1] Excludes IPH; Projections based on sum of [a] Midpoint of 2015 Adjusted EBITDA guidance as presented on May 6, 2015 and [b]1Q15 Adjusted EBITDA not realized due to delayed acquisition closing; [2]2015 Net Debt/EBITDA based on current cash balance; 2016-2018 projections assumes cash builds on the balance sheet with no capital allocation decisions

 DYNEGY

IPH Credit Profile







Current Status Case
- Includes only existing capacity sales, Retail sales, rail agreements and other cost structure improvements
- Current PRIDE program improvements

Base Case
- Ongoing MISO capacity sales at target prices and volumes
- Retail book renewal

Incremental Case
- Energy prices reflect underlying structural changes in the industry

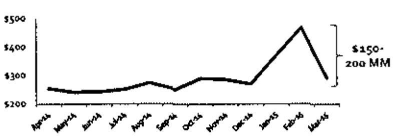
The outlook for IPH has materially improved through 2018

[1] After $23 MM annual G&A allocation; 2015 Net Debt/EBITDA based on current cash balance; 2016-2018 projections assume cash builds on the balance sheet with no incremental capital allocation decisions

 DYNEGY

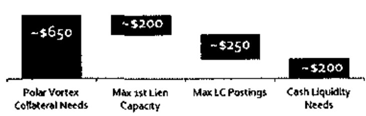
Liquidity Requirements

Working Capital[1]	$150-200 MM



- Working capital needs vary with seasonality and are typically highest in the winter as commodity prices rise and impacts payables and receivables

Natural Gas Purchases	$150-250 MM



- Assumes current gas fleet and pricing from Polar Vortex

Potential Future Exposure	$100-150 MM

- Reflects potential requirements due to power price volatility
- Exchanges used to primarily manage seasonal variability

Semi-Annual Interest Payments	$215 MM

- Interest payments on acquisition financing payable May 1 and November 1; $185 MM
- Legacy Dynegy Inc. due June 1 and December 1; $30 MM

Dynegy Inc. current liquidity of ~$1,500 MM, including ~$600 MM of cash[2]

Existing cash balances sufficient to meet liquidity requirements

[1] Historical working capital for the combined company, excluding cash, [2] Excludes IPH

 DYNEGY

Adjusted EBITDA Sensitivities

Impact of +$1/MMBtu Natural Gas Price on Adjusted EBITDA[1]

Previous Sensitivity	~$360 MM

Advancing the historical time frame changes our estimate of the commodity price relationships

Market	ATC Spread ($/MWh)	MM MWh	~$ MM
NY/NE	$0.21	17	$4
PJM	($1.12)	32	($36)
West	($0.22)	3	-
Gas Segment	**($0.62)**	**53**	**($33)**
MISO	$3.63	20	$72
PJM	$5.60	24	$134
New England	$7.34	2	$14
Coal Segment	**$4.82**	**46**	**$220**
IPH	**$3.85**	**26**	**$102**
Current Sensitivity	$2.31	125	~$290

PJM[2] (ATC in $/MWh)	2013	2014	2015	2016
Gas ATC Spread	($0.45)	($0.09)	($1.12)	($2.57)
Coal ATC Spread	$6.53	$6.68	$5.87	$3.88
Sensitivity ($ MM)	~$140	~$160	~$205	~$10

Dampened Sensitivity to Natural Gas Prices

- Updating analysis with more recent forward price observations (mid-2012 to mid-2015) results in a reduction in the estimated natural gas price sensitivity
- Reflects a larger offset from changes in heat rate as compared to prior estimate
- Sensitivities are approximately symmetrical due to predominantly baseload portfolio

Structural Changes Likely Impacting Commodity Relationships

- First wave of plant retirements impacting market clearing heat rates across markets
- Locational advantage of natural gas plants impacts their delivered fuel cost projections
- Potential for coal-fired units to set the price in more hours providing support for higher market clearing heat rates

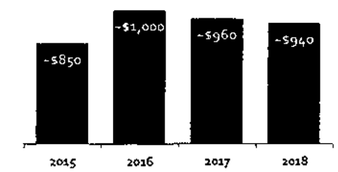
PJM Sensitivity to Natural Gas is Declining
Truncating the analysis to one-year historical periods to emphasize changing commodity relationship in PJM shows sensitivity to natural gas in PJM is declining

Structural changes in the industry dampening the portfolio's sensitivity to natural gas prices

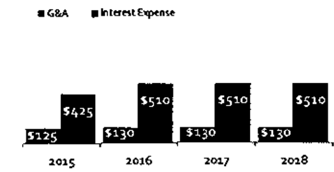
[1] Reflects delivered natural gas prices, Adjusted EBITDA is a non-GAAP measure; [2] Decomposed from 36 month calculation used above, reflects using historical forward price data to forecast the sensitivities; 2013 and 2016 reflect partial years

Cost Structure and Capital Spending

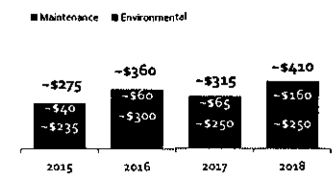
Operating & Maintenance Expense ($ MM)



G&A and Interest Expense[1] ($ MM)



Capital Spending[2] ($ MM)



Operating & Maintenance Expense

- Underlying spend held flat; declining trend over the forecast period largely reflects Brayton Point retirement

Capital Spending

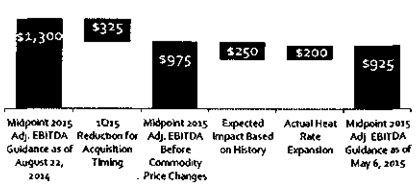
- Recurring maintenance spending reflects normalized capital spending
- 2016 increase reflects timing of gas plant outages to synchronize outages with uprates and expansions
- 2016 capital spending reflects reliability investments; additional capital may be allocated to reliability investments

Disciplined cost management over the forecast period

[1] Reflects cash interest; [2] See Appendix for additional detail, 2015 reflects partial year impact of acquired assets, excludes ARO

Adjusted EBITDA Sensitivities

Adjusted EBITDA and Adjusted EBITDA Sensitivities in Practice[1] ($ MM)



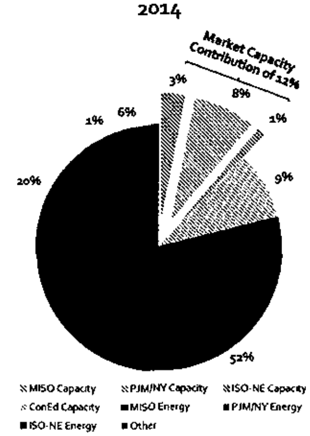
The Walk from August 22, 2014 Guidance

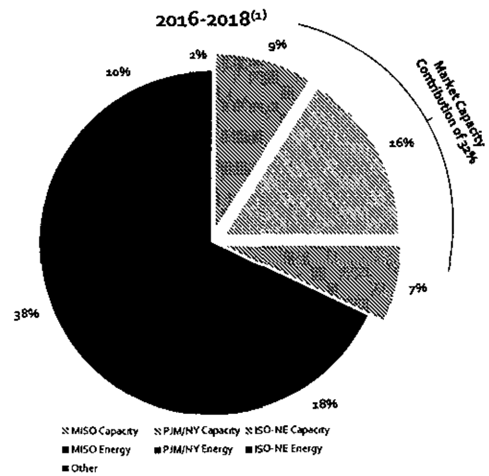
1. NYMEX Natural gas prices declined by $1.12 per MMbtu (less than $1.00 per MMbtu on a delivered basis)
2. Historical commodity price relationships would imply a ~$250 MM drop in Adjusted EBITDA
3. Adjusted EBITDA guidance was only affected by ~$50 MM
4. Actual heat rate expansion for Dynegy plants was greater than implied by sensitivity analysis
   - For example, on-peak heat rates for natural gas units at AD Hub increased by over 6,500 Btu/kwh versus expected heat rate increase of ~3,200 Btu/kwh

Market heat rates higher than forecast by sensitivity analysis

[1] Adjusted EBITDA is a non-GAAP measure; reconciliations to GAAP can be found in the Appendix

Gross Margin Composition



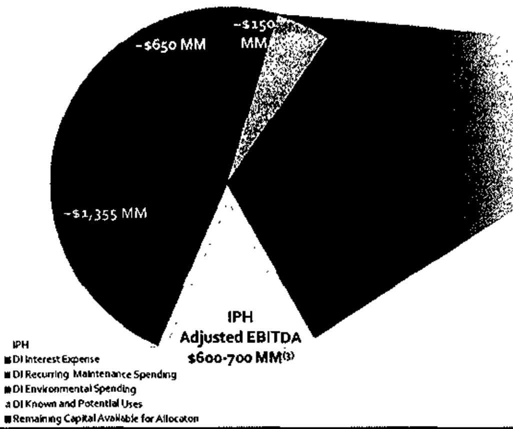


Increasing gross margin from more diverse portfolio combined with known capacity sales supports capital allocation

[1] Reflects Incremental Case

Capital Allocation

2016-2018 Cumulative Adjusted EBITDA[1]
$3,900-4,900 MM



Capital Available for Allocation
$1,100-2,000 MM

Known Uses
- Preferred Dividend and Term Loan Principal payment ($75 MM)

Likely Uses
- Uprates and discretionary reliability investment (~$150 MM)[2]
- Share repurchases
- Balance Sheet improvements

Significant capital available for allocation

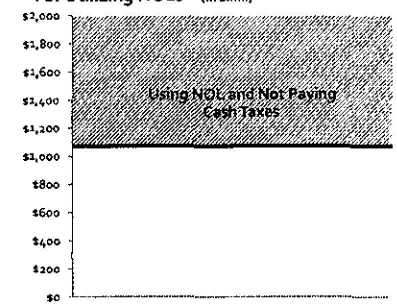
[1] Adjusted EBITDA is a non-GAAP measure; reconciliations to GAAP can be found in the Appendix; [2] Will be reflected in Maintenance Capital Spending; [3] IPH excluded because of ring fence

NOL Carryforwards Available to Shield Cash Taxes

NOL Position (12/31/2014)

- Federal tax NOL carryforward of ~$3.5 billion[1]
- ~$1.6 billion of NOL carryforwards currently available without limitation
- ~$1.9 billion of NOL carryforwards subject to annual use limitations[1]
- ~$900 MM of limited NOL carryforwards available over the next five years <u>plus</u> aggregate taxable losses, if any

Projected Annual Adjusted EBITDA Threshold For Utilizing NOLs[2] (in $MM)



Dynegy not a cash taxpayer through at least 2018[3]

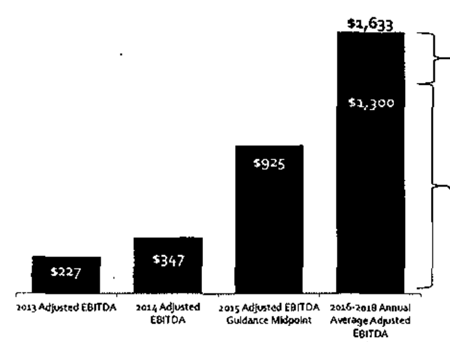
[1] Subject to IRC 382 limitations; NOL carryforwards could be further limited if the company experiences another ownership change as defined in IRC 382; [2] Calculation for threshold Adjusted EBITDA to shield cash taxes based on 4-Year Average Adjusted EBITDA; [3] May be subject to some minor state and AMT payments

Finance Summary

- More diversified gross margin with a large component of known capacity payments drives capital allocation
- Disciplined execution, balance sheet management, and internal improvements driving higher ROIC
- Right-sized balance sheet with sufficient liquidity in place
- Significant excess capital available for allocation

Adjusted EBITDA Growth

2013 through 2016-2018 Adjusted EBITDA[1] ($ MM)



Incremental Case
- Dynegy view of energy prices, spark spreads, and dark spreads
- No PRIDE contribution beyond announced targets

Base Case
- Forward curves as of May 13, 2015
- Retail book renewal at forward curves
- Contribution from PJM 16/17 and 17/18 Planning Year Transitional/Incremental Auctions
- Capacity Performance contribution for 18/19 Planning Year
- Capacity expansions and uprates
- No PRIDE contribution beyond announced targets

2016-2018 Adjusted EBITDA
$3,900-4,900 MM

Significant growth in Adjusted EBITDA

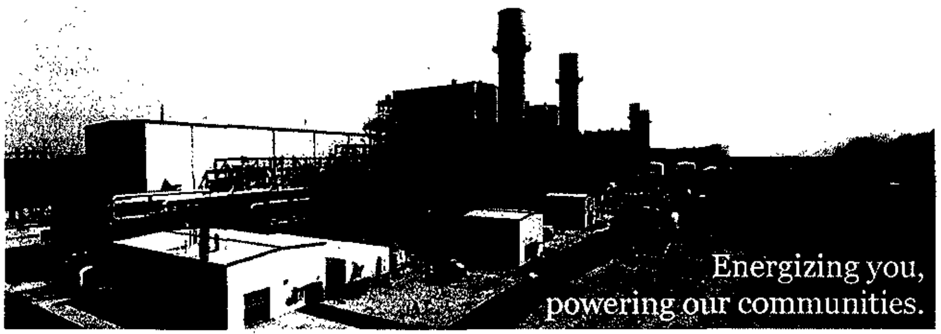
[1] Adjusted EBITDA is a non-GAAP measure; reconciliations to GAAP can be found in the Appendix; 2015 Adjusted EBITDA Guidance Midpoint as presented on May 6, 2015 and reflects only owning the acquired assets for nine months, 2016-2018 Annual Average Adjusted EBITDA ranges reflect dividing the low end and high end of the 2016-2018 Adjusted EBITDA guidance range by three

DYNEGY

Investor Day 2015

Q&A

Hanging Rock Energy Facility



DYNEGY

Closing Remarks

Bob Flexon
President and CEO

Independence Energy Facility

Appendix

DYNEGY

Key Themes from Investor Day 2015

How Dynegy Wins

Shifting Market Dynamics Driving Higher Prices	Optimal Portfolio Benefits from Market Shift	Shareholder Value Creation
Baseload Retirements • ~50 GW of generation exits ISO-NE, PJM and MISO (15% of capacity) **Replaced with Less Reliable Intermittent Resources** • Reliance on renewables and demand response drives system instability **Performance Incentives Introduced in PJM and ISO-NE** • Set to drive a second wave of retirements, putting up to 25% of older, less reliable assets at risk	**Balanced Portfolio of Reliable Assets** • Balanced environmentally compliant portfolio • Coal and natural gas fleets at 60-80% capacity factors • Strong and improving reliability performance **Low-Cost Competitive Advantage** • Advantageous access to low-cost natural gas for CCGTs and low delivered fuel costs for coal, below market averages in PJM and MISO • Manageable environmental spend concentrated 2019-2023 **Located in Most Attractive Markets** • ~90% of generation in ISO-NE, PJM, and MISO • Performance incentives reward high-quality assets in large portfolios	**Capturing the Upside** • \$155 MM in synergies captured • Expanding PRIDE program • Open energy portfolio with strong core of capacity payments (1/3 of gross margin) • Improving capacity markets • Low-cost capacity uprates with 300 MW of CCGT generation online by 2016 **Disciplined Financial Management** • Strong Balance Sheet with no near-term debt maturities • ~\$1,500 MM in current liquidity; ~\$600 MM cash • ROIC improved from 5.5% in 2013 to 10.8% in 2015 **Capital Allocation Opportunities** • \$1,100 – 2,000 MM of discretionary capital over 2016-2018 time period • Under-valued share price

DYNEGY

Our Executive Management Team

Bob Flexon
President and Chief Executive Officer
Prior Experience:
- UGI Corporation – CFO
- *Foster Wheeler AG - CEO*
- NRG Energy – CFO, COO
- Hercules and ARCO – various financial roles

Hank Jones
EVP and Chief Commercial Officer
Prior Experience:
- Deutsche Bank – Managing Director, North American Power and Gas Sales and Origination
- EDF North American – COO and Head of Trading

Carolyn Burke
EVP, Business Operations & Systems
Prior Experience:
- J.P. Morgan – Global Controller, Commodities
- NRG Energy – VP & Corporate Controller, Financial Planning & Analysis

Mario Alonso
EVP, Strategic Development
Prior Experience:
- Dynegy – VP & Treasurer; VP, Mergers & Acquisitions

Sheree Petrone
EVP, Retail
- Prior Experience:
- *Exelon Corporation - Commercial Integration, Energy Trading & Marketing, Fuels and Retail*
- Trigen – Business Development

Clint Freeland
EVP and Chief Financial Officer
Prior Experience:
- NRG Energy – SVP, Strategy & Financial Structure, CFO, Treasurer
- Enron – Director, Finance

Catherine Callaway
EVP, General Counsel and Chief Compliance Officer
Prior Experience:
- NRG Energy – General Counsel, NRG Gulf Coast
- *Calpine – VP & Managing Counsel, Corporate Restructuring*
- Reliant Energy – General Counsel

Marty Daley
EVP, Plant Operations Gas
Prior Experience:
Dynegy - Managing Director, Asset Management; Senior Director, Regulatory Affairs & Administrative Services

Dan Thompson
EVP, Plant Operations Coal
Prior Experience:
- Dynegy – Operations Head, Northeast and West Regions
- ~~Illinois Power Company – VP Engineering~~

Julius Cox
EVP, Chief Administrative Officer
Prior Experience:
- Dynegy – VP, Human Resources and Business Services; VP Human Resources
- Arthur Anderson Consulting

DYNEGY

Board of Directors

Pat Wood
Chairman of the Board
Principal – Wood3 Resources
Currently serves on Board of Directors of Quanta Services Inc. and SunPower Corp.
Prior Experience:
- Federal Energy Regulatory Commission - Chairman
- Public Utility Commission of Texas - Chairman

Hilary E. Ackermann
Prior Experience:
- Goldman Sachs Bank USA – Chief Risk Officer; Chaired Operational Risk, Credit Risk and Middle Market Loan Committees, Vice Chair of Bank Risk Committee; Chair GS Group level Operational Risk Committee
- Goldman Sachs & Co – Managing Director, Credit *Risk Management & Advisory*
- Swiss Bank Corporation – Assistant Department Head

Paul M. Barbas
Prior Experience:
- DPL Inc. and DP&L – President and Chief Executive Officer; Served on Board of Directors
- Chesapeake Utilities Corporation – Executive Vice President & Chief Operating Officer; Vice President
- Chesapeake Service Company – President
- Allegheny Power – Executive Vice President President of Ventures unit

Bob Flexon
President and Chief Executive Officer
Prior Experience:
- UGI Corporation – CFO
- Foster Wheeler AG - CEO
- NRG Energy – CFO, COO
- Hercules and ARCO – various financial roles

Richard Kuersteiner
Prior Experience:
- Board of Directors of Dex One Corporation
- Franklin Templeton Investments – Associate General Counsel; Director of Restructuring; Managing *Corporate Counsel*
- Member of Stanford Institutional Investors Forum
- Managing Attorney, Navy Office of the General Counsel
- Special Assistant US Attorney, DOJ
- Senior Attorney, NASA

Jeffrey S. Stein
Co-Founder and Managing Partner of Power Capital Partners LLC
Currently serves on Board of Directors of Granite Ridge Holdings, LLC and US Power Generating Company
Prior Experience:
- Durham Asset Management LLC – Co-Founder and Principal; Co-Director of Research
- The Delaware Bay Company – Director
- Shearson Lehman Brothers – Associate in Capital Preservation & Restructuring Group

John R. Sult
EVP and CFO Marathon Oil
Prior Experience:
- El Paso Corporation – Executive Vice President Chief Financial Officer; Senior V.P. and CFO; Senior V.P. and Controller; Chief Accounting Officer
- El Paso Pipeline GP Company – Executive Vice President and Chief Financial Officer; Senior Vice President and CFO and Controller
- El Paso Pipeline Group - Senior Vice President, CFO and Controller
- Halliburton Energy Services – Vice President and Controller
- Arthur Andersen LLP – Audit Partner

DYNEGY

Dynegy Generation Facilities

Portfolio/Facility[1]	Location	Net Capacity[2]	Primary Fuel	Dispatch Type	Market Region
Coal Segment					
Baldwin	Baldwin, IL	1,815	Coal	Baseload	MISO
Havana[3]	Havana, IL	434	Coal	Baseload	MISO
Hennepin	Hennepin, IL	294	Coal	Baseload	MISO
Wood River	Alton, IL	465	Coal	Baseload	MISO
Stuart*	Aberdeen, OH	904	Coal	Baseload	PJM
Miami Fort 7&8*	*North Bend, OH*	653	Coal	Baseload	PJM
Miami Fort (CT)	North Bend, OH	68	Oil – CT	Peaking	PJM
Zimmer*	Moscow, OH	628	Coal	Baseload	PJM
Conesville*	Conesville, OH	312	Coal	Baseload	PJM
Killen*	Manchester, OH	204	Coal	Baseload	PJM
Kincaid	Kincaid, IL	1,108	Coal	Baseload	PJM
Brayton Point	Somerset, MA	1,493	Coal	Baseload	ISO-NE
Coal Segment TOTAL		8,378			
IPH					
Coffeen	Coffeen, IL	915	Coal	Baseload	MISO
Joppa/EEI*[4]	Joppa, IL	802	Coal	Baseload	MISO
Newton	Newton, IL	1,230	Coal	Baseload	MISO
Duck Creek	Canton, IL	425	Coal	Baseload	MISO
E.D. Edwards	Bartonville, IL	685	Coal	Baseload	MISO
IPH TOTAL		4,057			

NOTES:
1) Dynegy owns 100% of each unit listed except for those marked by an asterisk (*). Total Net Capacity set forth in this table for partially owned units includes only Dynegy's proportionate share of that facility's gross generating capacity.
2) Unit capabilities are based on winter capacity ratings.
3) Represents Unit 6 generating capacity.
4) Joppa has an additional 226 MW of natural gas-fueled capacity currently in maintenance status.

DYNEGY

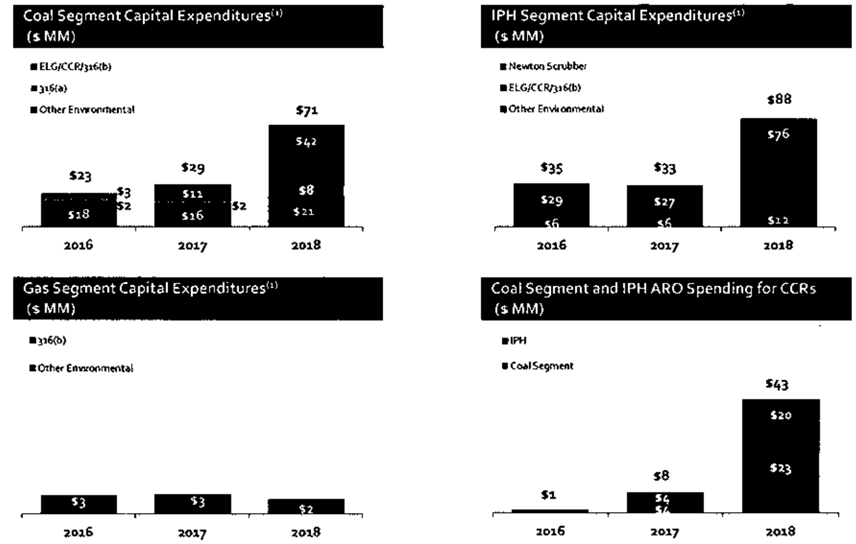
Dynegy Generation Facilities, continued

Portfolio/Facility[1]	*Location*	*Net Capacity*[2]	*Primary Fuel*	*Dispatch Type*	*Market Region*
Gas Segment					
Casco Bay	Veazie, ME	538	Gas – CCGT	Intermediate	ISO-NE
Milford	Milford, CT	579	Gas – CCGT	Intermediate	ISO-NE
Lake Road	Dayville, CT	856	Gas – CCGT	Intermediate	ISO-NE
Dighton	Dighton, MA	187	Gas – CCGT	Intermediate	ISO-NE
MASSPOWER	Indian Orchard, MA	280	Gas – CCGT	Intermediate	ISO-NE
Independence	*Oswego, NY*	1,108	Gas – CCGT	Intermediate	NYISO
Kendall	Minooka, IL	1,209	Gas – CCGT	Intermediate	PJM
Ontelaunee	Ontelaunee Township, PA	560	Gas – CCGT	Intermediate	PJM
Hanging Rock	Ironton, OH	1,296	Gas – CCGT	Intermediate	PJM
Washington	Beverly, OH	648	Gas – CCGT	Intermediate	PJM
Fayette	Masontown, PA	649	Gas – CCGT	Intermediate	PJM
Liberty	Eddystone, PA	600	Gas – CCGT	Intermediate	PJM
Dicks Creek	Monroe, OH	153	Gas – CT	Peaking	PJM
Lee	Dixon, IL	712	Gas – CT	Peaking	PJM
Elwood*	Elwood, IL	788	Gas – CT	Peaking	PJM
Richland	Defiance, OH	447	Gas – CT	Peaking	PJM
Stryker	Stryker, OH	19	Oil	Peaking	PJM
Moss Landing	Moss Landing, CA				
Units 1-2		1,020	Gas – CCGT	Intermediate	CAISO
Units 6-7		1,509	Gas – CT	Peaking	CAISO
Oakland	Oakland, CA	165	Oil	Peaking	CAISO
Gas Segment TOTAL		13,323			
TOTAL GENERATION		25,758			

NOTES:
1) Dynegy owns 100% of each unit listed except for those marked by an asterisk (*). Total Net Capacity set forth in this table for partially owned units includes only Dynegy's proportionate share of that facility's gross generating capacity.
2) Unit capabilities are based on winter capacity ratings.

DYNEGY

Environmental Capital and ARO Spending



[1] Includes capital spending to meet Coal Combustion Residuals, Effluent Limit Guidelines, 316(b), 316(a), and Once-Through Cooling requirements based on our assumptions

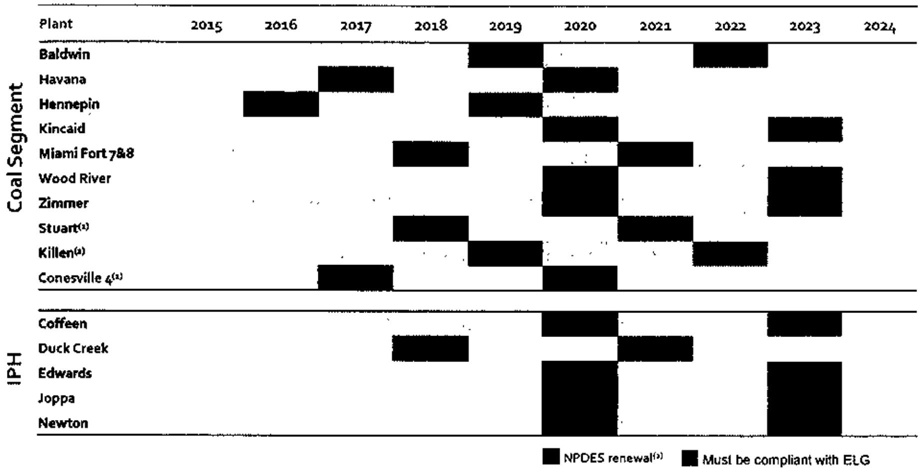
Environmental Equipment Summary

SDA: Spray Dry Absorption
DSI: Dry Sorbent Injection
SCR: Selective Catalytic Reduction

			Coal Segment[1]											IPH						
			Baldwin 1-2	Baldwin 3	Havana 6	Hennepin 1-2	Wood River 4-5	Kincaid	Miami Fort 7-8	Zimmer	Conesville 4[2]	Stuart 1-4[2]	Killen[2]	Coffeen 1-2	Duck Creek 1	Edwards 1	Edwards 2	Edwards 3	Joppa 1-6	Newton 1-2
Meets CSAPR	SO_2	Scrubber	SDA	SDA	SDA			DSI	Wet	Wet	Wet	Wet	Wet	Wet	Wet					
	NOx	Low NOx Burners		✓	✓	✓	✓		✓	✓	✓	✓	✓		✓		✓	✓	✓	✓
		Overfire Air	✓	✓	✓	✓	✓	✓						✓			✓	✓	✓	✓
		SCR	✓		✓			✓	✓	✓	✓	✓	✓	✓	✓			✓		
Meets MATS	Mercury	Injection/ Oxidation Systems	✓	✓	✓	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
	Particulate Matter	Electrostatic Precipitator	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
		Baghouse	✓	✓	✓	✓														

[1] Brayton Point is not included in this list; it is fully compliant with federal regulations until its scheduled retirement in June 2017
[2] Facility is partially owned but not operated by Dynegy

ELG Compliance Timeline



Note: Brayton Point is fully compliant with federal environmental regulations until its scheduled retirement in June 2017
[1] Facility is partially owned but not operated by Dynegy, [2] Compliance expected within 36 months after NPDES permit renewed

EPA Effluent Limit Guidelines – Assumed Compliance Requirements

Wastewater Streams Addressed	US EPA Preferred Technologies
FGD Wastewater	Best Professional Judgment, Chemical Precipitation + Biological Treatment
Fly Ash Transport Water	Dry Handling
Bottom Ash Transport Water	Impoundment, Dry Handling for units >400 MW
Combustion Residual Leachate	Impoundment
FGMC Wastewater	Dry Handling
Gasification Wastewater	Evaporation
Nonchemical Metal Cleaning Waste	Chemical Precipitation

- ELG rule scheduled for signature in 3Q15
- Compliance expected within 36 months after NPDES permit renewed; renewals occur from 2016-2020
- Compliance modifications not planned at Brayton Point due to planned retirement in 2017

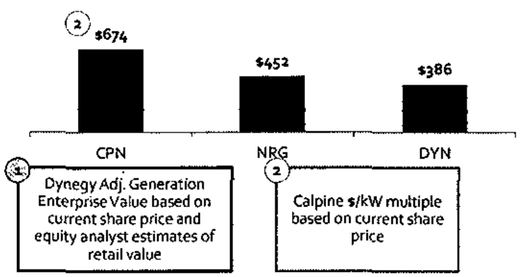
Dynegy's Market Valuation

($ MM unless otherwise noted)

Valuation Comparables

	Calpine	nrg	Dynegy
Adj. Enterprise Value[(a)]	$17,900	$27,400	$9,600
Less: Retail[(b)]	--	(3,200)	(240)
Less: Other[(c)]	--	(2,380)	--
Adj. Generation Enterprise Value	**$17,900**	**$21,820**	**$9,360**
Memo: Total Capacity (MW)	*26,548*	*48,280*	*24,249*

Implied $/kW



Source: *Company filings and equity research.*
(a) Reflects enterprise value adjusted for the net present value of hedges and planned environmental capital expenditures
(b) Reflects estimated value of retail segment based on equity research reports
(c) Reflects estimated value of NRG Yield based on equity research reports

Appendix
Reg G Reconciliations

Reg G Reconciliation – Dynegy 2016-2018 Adjusted EBITDA Guidance

DYNEGY INC.
2016-2018 ADJUSTED EBITDA GUIDANCE
(UNAUDITED) (IN MILLIONS)

Dynegy has not completed its purchase price allocation or determined the estimated useful lives of the assets to be acquired. The 2016-2018 guidance below was prepared using reasonable efforts and based on currently available information assuming the following: (a) the ECP and Duke transactions closed on April 1 and April 2, 2015 respectively, (b) all of the purchase price is allocated to working capital, property, plant and equipment; identifiable intangibles; and the elimination of historical goodwill; and (c) property, plant and equipment is depreciated over an average useful life of 25 years.

The following table provides summary financial data regarding our 2016-2018 Adjusted EBITDA guidance.

	Dynegy Consolidated	
	Low	High
Net income attributable to Dynegy Inc.	$ 1,055	$ 2,045
Plus / (Less)		
Interest expense	1,545	1,645
Operating income	2,600	3,690
Depreciation expense	1,360	1,280
Amortization of intangible assets and liabilities, net	(60)	(70)
EBITDA / Adjusted EBITDA (1)	$ 3,900	$ 4,900

(1) EBITDA and Adjusted EBITDA are non-GAAP measures

ILLINOIS POWER HOLDINGS (IPH)
2016-2018 ADJUSTED EBITDA GUIDANCE
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our IPH 2016-2018 Adjusted EBITDA guidance

	Illinois Power Holdings	
	Low	High
Operating income	$ 496	$ 586
Depreciation expense	110	120
Amortization of intangible assets and liabilities, net	(6)	(6)
EBITDA / Adjusted EBITDA (1)	$ 600	$ 700

(1) EBITDA and Adjusted EBITDA are non-GAAP measures. Management does not allocate interest expense on a segment level and therefore uses Operating income as the most directly comparable GAAP measure

Reg G Reconciliation – Dynegy 2015 Adjusted EBITDA and Guidance

DYNEGY INC.
UPDATED 2015 ADJUSTED EBITDA
(UNAUDITED) (IN MILLIONS)

Dynegy has not completed its purchase price allocation or determined the estimated useful lives of the assets to be acquired. The 2015 updated guidance below was prepared using reasonable efforts and based on currently available information assuming the following: (a) the transactions will close on April 1, 2015, (b) February 10, 2015 price curves, (c) all of the purchase price is allocated to working capital; property, plant and equipment; and the elimination of historical goodwill; and (d) property, plant and equipment is depreciated over an average useful life of 25 years.

The following table provides summary financial data regarding our updated 2015 Adjusted EBITDA guidance:

	Dynegy Consolidated	
	Low	High
Net loss attributable to Dynegy Inc.	$ (230)	$ (50)
Plus / (Less):		
Interest expense	535	535
Operating income	$ 305	$ 485
Depreciation expense	420	440
Amortization expense	(10)	(20)
EBITDA (1)	715	905
Plus / (Less):		
Transaction fees and expenses	80	85
Integration costs	30	35
Adjusted EBITDA (1)	$ 825	$ 1,025

(1) EBITDA and Adjusted EBITDA are non-GAAP measures.

Reg G Reconciliation – Dynegy 2015 Adjusted EBITDA Guidance as of August 22, 2014

DYNEGY INC.
2015 ADJUSTED EBITDA GUIDANCE
(UNAUDITED) (IN MILLIONS)

Dynegy has not completed its purchase price allocation or determined the estimated useful lives of the assets to be acquired. The 2015 guidance below was prepared using reasonable efforts and based on currently available information assuming the following: (a) the transactions will close on December 31, 2014, (b) all of the purchase price is allocated to working capital, property, plant and equipment; and the elimination of historical goodwill; and (c) property, plant and equipment is depreciated over an average useful life of 25 years.

The following table provides summary financial data regarding our 2015 Adjusted EBITDA guidance.

	Dynegy Consolidated	
	Low	High
Net Income attributable to Dynegy Inc.	$ 220	$ 375
Plus / (Less):		
Interest expense	465	490
Operating Income	685	865
Depreciation expense	475	495
Amortization of intangible assets and liabilities, net	(10)	(20)
EBITDA (1)	1,150	1,340
Plus / (Less):		
Acquisition and integration costs	50	60
Adjusted EBITDA (1)	$ 1,200	$ 1,400

(1) EBITDA and Adjusted EBITDA are non-GAAP measures

Reg G Reconciliation – 2014 Adjusted EBITDA

DYNEGY INC.
REPORTED ADJUSTED EBITDA
TWELVE MONTHS ENDED DECEMBER 31, 2014
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our Adjusted EBITDA for the twelve months ended December 31, 2014:

Net loss attributable to Dynegy Inc.	$ (273)
Plus / (Less):	
Net income attributable to noncontrolling interest	6
Income tax benefit	(1)
Interest expense	223
Depreciation expense	247
Amortization expense	50
EBITDA (1)	$ 252
Plus / (Less):	
Bankruptcy reorganization items, net	(3)
Acquisition and integration costs	35
Mark-to-market (income) loss, net	28
Change in fair value of common stock warrants	40
Net income attributable to noncontrolling interest	(6)
Gain on sale of assets, net	(18)
Other	19
Adjusted EBITDA (1)	$ 347

(1) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on February 24, 2015, for definitions, utility and uses of such non-GAAP financial measures.

Reg G Reconciliation – 2013 Adjusted EBITDA

DYNEGY INC.
REPORTED ADJUSTED EBITDA
TWELVE MONTHS ENDED DECEMBER 31, 2013
(UNAUDITED) (IN MILLIONS)

The following table provides summary financial data regarding our Adjusted EBITDA for the 12 months ended December 31, 2013:

Net loss attributable to Dynegy Inc.	$ (356)
Plus / (Less):	
Income from discontinued operations, net of tax	(3)
Income tax benefit	(58)
Interest expense	97
Loss on extinguishment of debt	11
Depreciation expense	216
Amortization expense	251
EBITDA (1)	$ 158
Plus / (Less):	
Bankruptcy reorganization items, net	1
Acquisition and integration costs	20
Mark-to-market loss, net	37
Change in fair value of common stock warrants	1
Other	10
Adjusted EBITDA (1)	$ 227

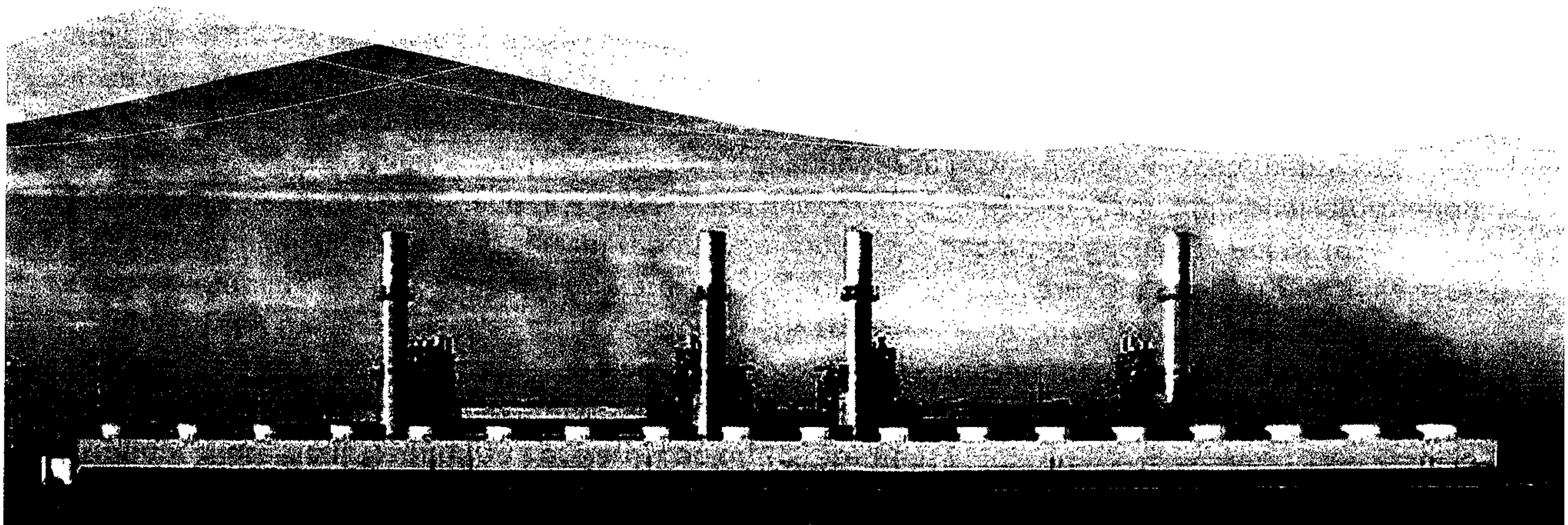
(1) EBITDA and Adjusted EBITDA are non-GAAP financial measures. Please refer to Item 2.02 of our Form 8-K filed on February 24, 2015, for definitions, utility and uses of such non-GAAP financial measures.

DYNEGY

Wolfe Research Power & Gas Leaders Conference

September 29, 2015

Bob Flexon, President and Chief Executive Officer



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Forward-Looking Statements

Cautionary Statement Regarding Forward-Looking Statements

This presentation contains statements reflecting assumptions, expectations, projections, intentions or beliefs about future events that are intended as "forward looking statements." You can identify these statements by the fact that they do not relate strictly to historical or current facts. Management cautions that any or all of Dynegy's forward-looking statements may turn out to be wrong. Please read Dynegy's annual, quarterly and current reports filed under the Securities Exchange Act of 1934, including its 2014 Form 10-K and first and second quarter 2015 Forms 10-Q for additional information about the risks, uncertainties and other factors affecting these forward-looking statements and Dynegy generally. Dynegy's actual future results may vary materially from those expressed or implied in any forward-looking statements. All of Dynegy's forward-looking statements, whether written or oral, are expressly qualified by these cautionary statements and any other cautionary statements that may accompany such forward-looking statements. In addition, Dynegy disclaims any obligation to update any forward-looking statements to reflect events or circumstances after the date hereof.

DYNEGY

Dynegy Investment Thesis

Right Assets

- ~26 GW of generation assets with fuel and geographic diversity
- Large efficient CCGT fleet sitting on top of shale gas
- Environmentally compliant, low-cost coal fleet
- Retail business that provides cost-effective risk mitigation and incremental earnings

Right Markets

- 90% of fleet located in markets with tightening reserve margins
- Nearly 15 GW in PJM and ISO-NE which have new capacity incentives that reward reliable generation
- Increasing contracted capacity revenues in gross margin

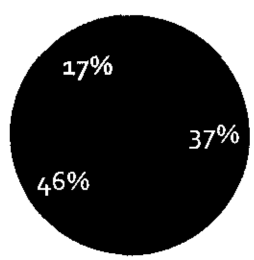
Right Management Team

- Strong track record of cost discipline and operational efficiency
- Over $500 MM in annual EBITDA improvement from PRIDE program and synergy capture
- Capital allocation program that allocates cash to the highest risk adjusted rate of return opportunities

Dynegy offers the right assets in the right markets managed for optimum performance

The Right Assets

Asset Mix



Net Capacity in MW [1]

Market	CCGT	Coal	Peakers	Total	% of Portfolio
PJM	~5,000	~3,800	~2,200	~11,000	~42%
ISO-NE	~2,400	~1,100	~400	~3,900	~15%
MISO	0	~7,100	~200	~7,300	~28%
NYISO	~1,100	0	0	~1,100	~4%
CAISO	~1,000	0	~1,700	~2,700	~11%
TOTAL	**~9,500**	**~12,000**	**~4,500**	**~26,000**	**100%**

Dynegy has more generation capacity from CCGTs in both PJM and ISO-NE than any other IPP

- ~5.0 GW of CCGT capacity in PJM, average age of 13 years
- ~2.4 GW of CCGT capacity in ISO-NE, average age of 15 years
- Retail business serving 22 TWhrs of load complementing our generation base

Best positioned IPP portfolio – with both scale and diversification

[1] Unit capabilities are based on winter capacity ratings

DYNEGY

The Right Markets

~90% of Dynegy's Generating Fleet (PJM, ISO-NE, NYISO, MISO)

	PJM	ISO-NE	NYISO	MISO	ERCOT	CAISO
Dynegy MWs % of total	*~11,000 MW ~42%*	*~3,900 MW ~15%*	*~1,100 MW ~4%*	*~7,300 MW ~28%*	*N/A*	*~2,700 MW ~11%*
High Scarcity Price Caps						
Capacity Market						
Capacity Market Design						
Stable Market Rules						
Performance Incentives						

PJM & ISO-NE lead the way in best structured markets

DYNEGY

Adjusted EBITDA Contributions[1]

PJM
(~11,000 MW)

Gross Margin Contributions:
Energy = ~50%
Capacity = ~45%
Retail = ~5%

- Largest merchant CCGT fleet in PJM
- Access to low cost gas
- Adding capacity to CCGTs via low cost uprates
- CCGTs run as baseload

~60%

ISO-NE/NY
(~5,000 MW)

Gross Margin Contributions:
Energy = ~60%
Capacity = ~40%

- Largest merchant CCGT fleet in ISO-NE
- Access to low cost gas
- Adding CCGT capacity via low cost uprates

~25%

MISO
(~7,300 MW)

Gross Margin Contributions:
Energy = ~65%
Capacity = ~30%
Retail = ~5%

- Greatest upside to recovering gas market
- IPH able to export ~850 MW to PJM increasing to ~1,050 MW
- Levers available to reduce costs in declining market
- If plants turn FCF negative retirements are an option

~15%

DYNEGY

Benefitting from being in the best structured markets

[1] ISO Adjusted EBITDA estimates exclude corporate allocations. CAISO's contribution to Adjusted EBITDA < 1%

Capacity Markets Responding

MISO

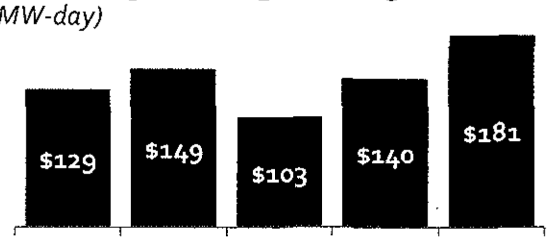
- Capacity sold through bilateral, wholesale, exports, auction and retail channels
- Illinois Power Agency recently procured 1,033 MW of Zone 4 capacity for PY 16/17 from Dynegy and three others at a weighted average price of $138.12 per MW-day
- Current mid-market broker quotes of $131.51 per MW-day for PY 17/18 and recent capacity sales of $147.95 per MW-day for PY 18/19

Zone 4 Clearing Price
($/MW-day)

PJM

- Capacity Performance (CP) structure rewards reliability
- Demand response resources struggle to meet same standards as fossil
- CP expected to force underperforming resources from the system

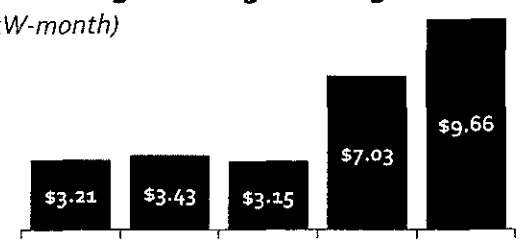
DYN's Weighted Avg Clearing Price
($/MW-day)



ISO-NE

- Performance Incentive (PI) structure rewards reliability
- PI expected to force underperforming resources from the system
- Strict minimum offer price requirement prevents a flood of resources from artificially suppressing capacity prices

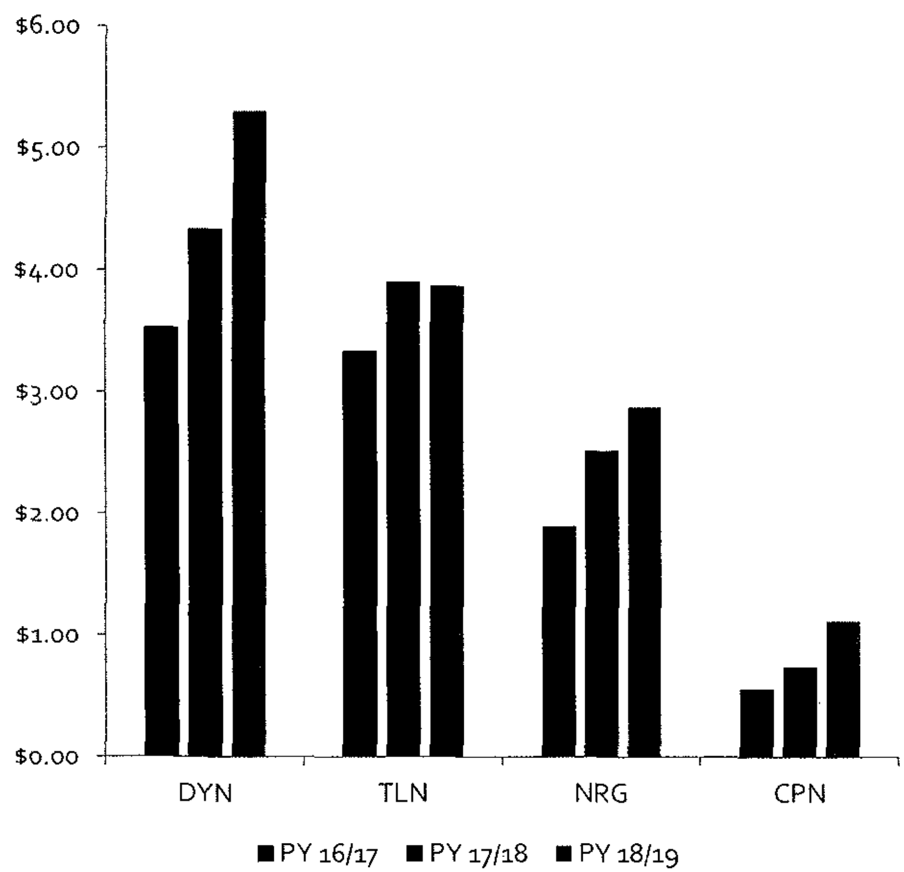
DYN's Weighted Avg Clearing Price
($/kW-month)



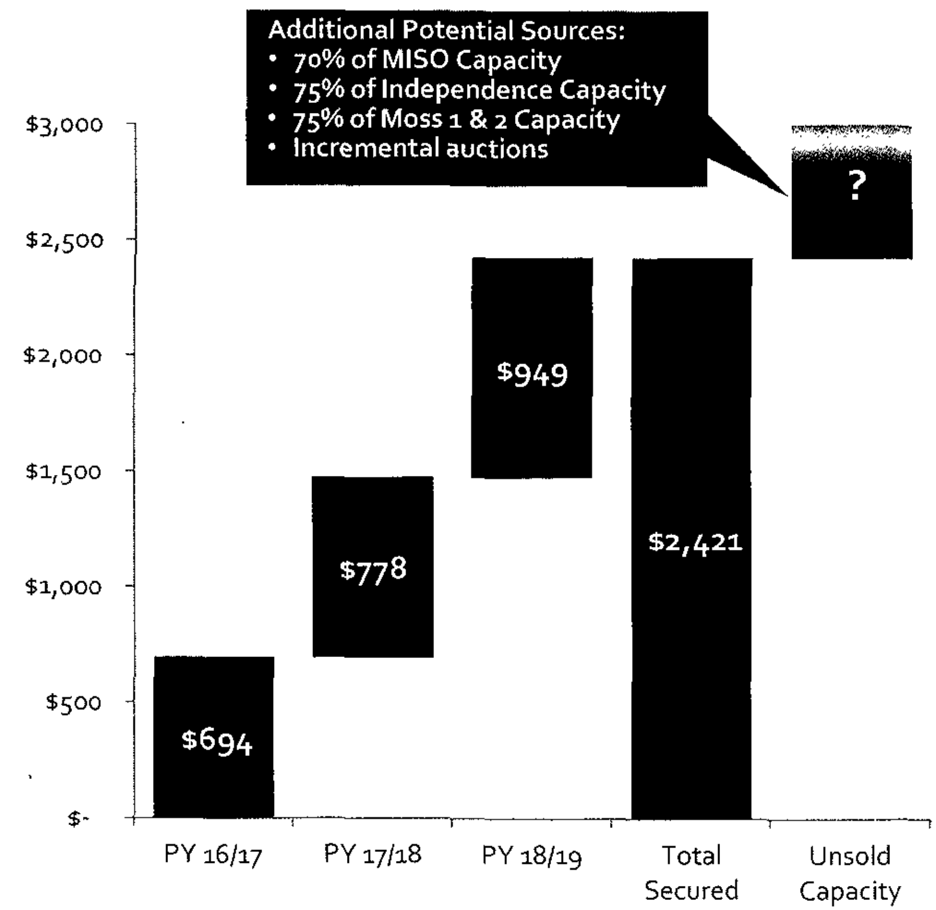
Capacity markets reflecting tighter reserve margins

Significant Capacity Revenues

PJM Capacity Revenues Per Share[1]



DYN Capacity Revenue Secured to Date ($ MM)



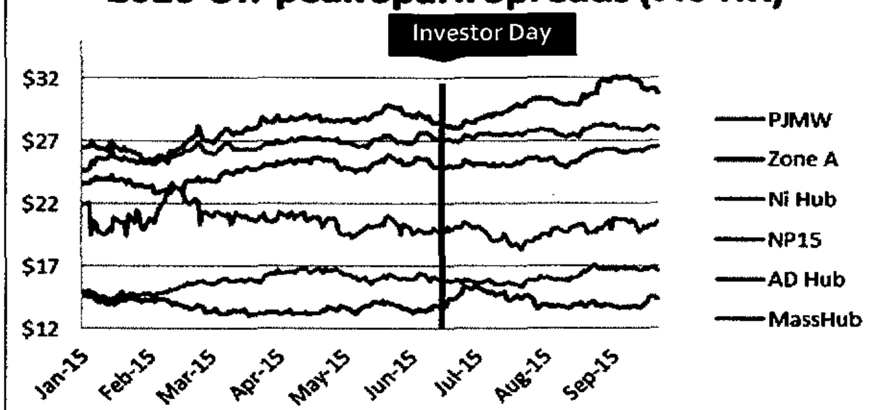
Dynegy, the IPP that benefited the most from PJM transition and capacity performance auctions

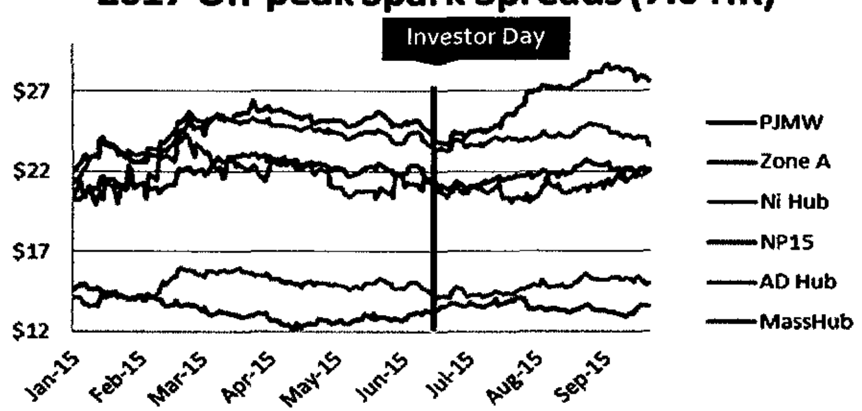
[1] PJM capacity revenues divided by shares outstanding

DYNEGY

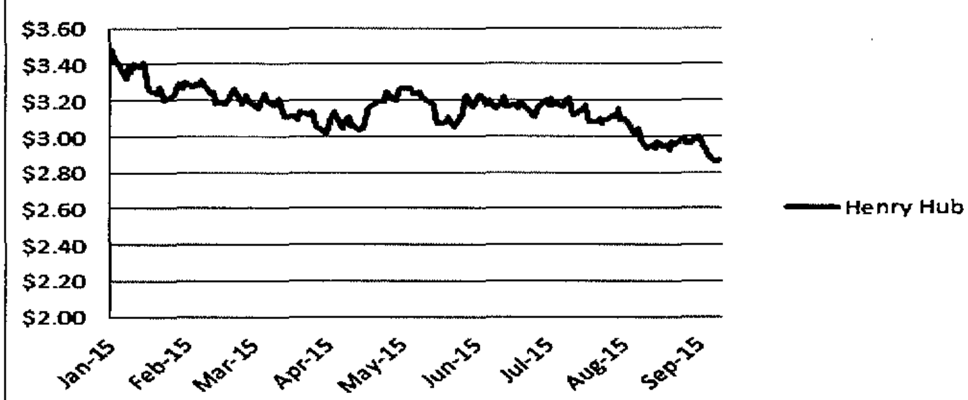
Dynegy Market Spark Spreads[1]

Dynegy market spark spreads expand...





..while Henry Hub prices decline



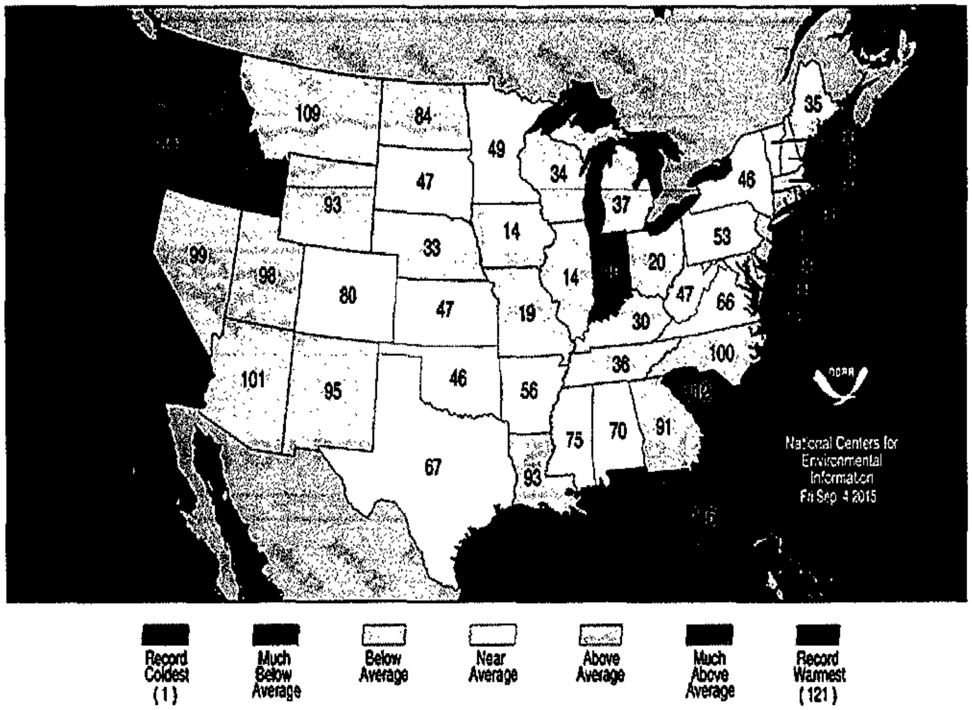
Pwr Hub	Gas Hub	Corresponding CCGTs	MW
PJMW	Tetco M3	Ontelaunee/Liberty	1,160
Zone A	Dom South	Independence	1,108
Ni Hub	Chicago CG	Kendall	1,209
NP 15	PG&E	Moss Landing 1 & 2	1,020
AD Hub	Dom South	Washington/Fayette/Hanging Rock	2,593
Mass Hub	Algonquin	Dighton/Lake Road/Masspower/Milford	1,902

Dynegy's low cost fuel advantage drives spark spreads

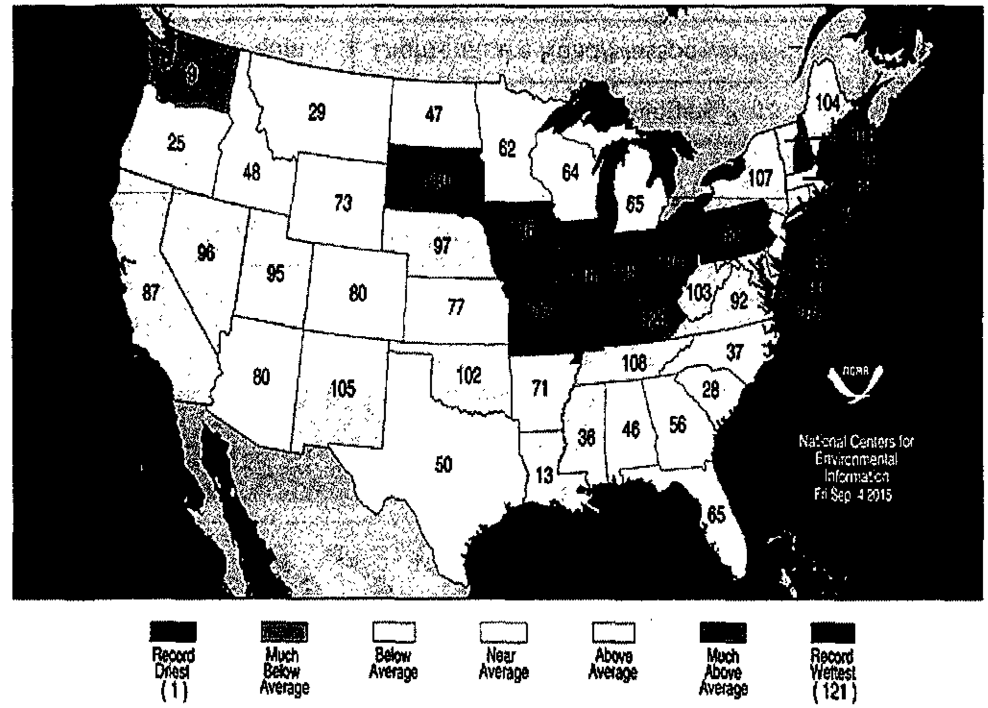
[1] Forward prices as of September 22, 2015

Summer Weather Rankings[1]

Statewide Maximum Temperature Ranks
June–August 2015
Period: 1895–2015



Statewide Precipitation Ranks
June–August 2015
Period: 1895–2015

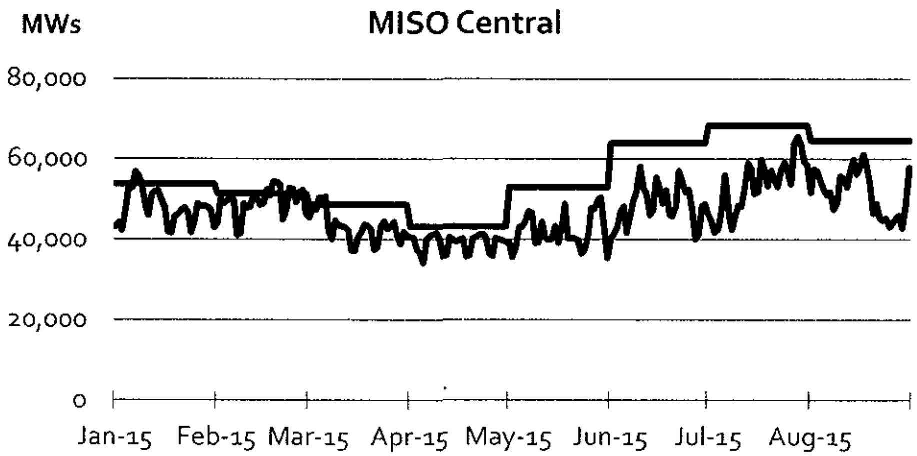


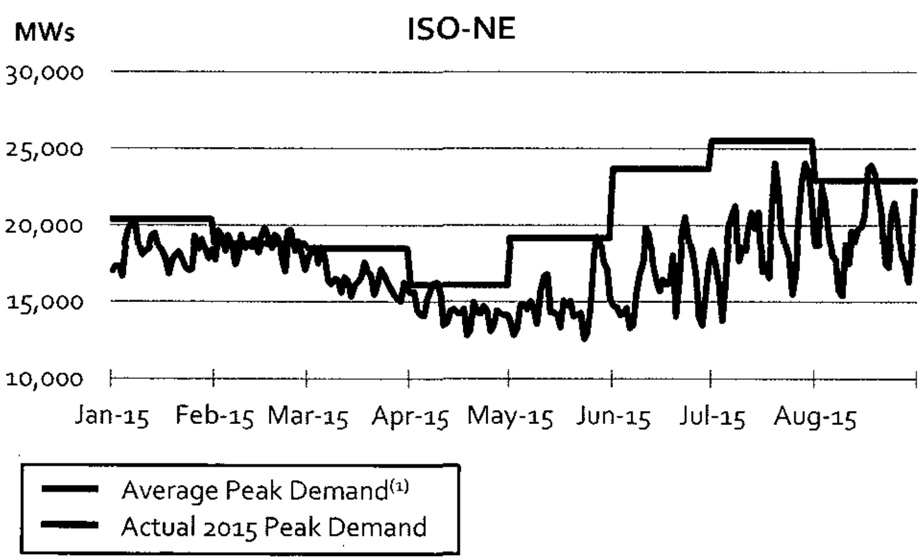
A lack of high max temps and increased precipitation lowered summer demand peaks

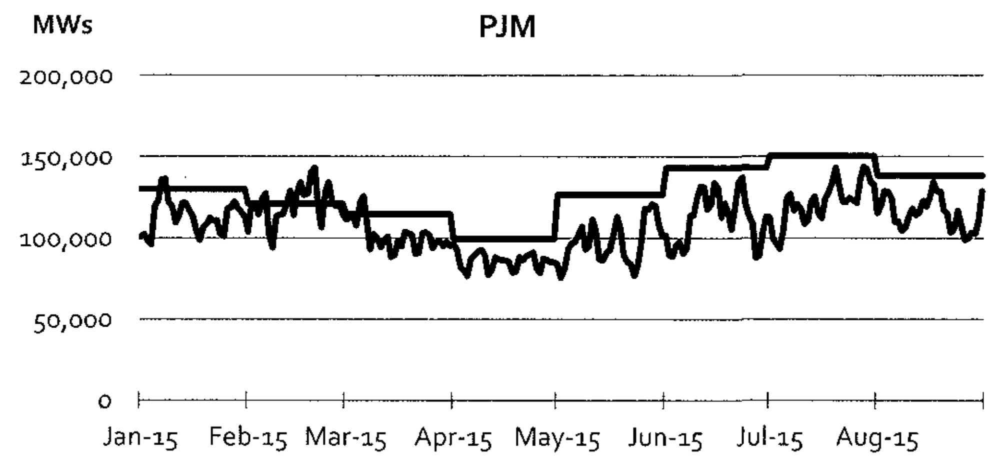
[1] Source: National Oceanic and Atmospheric Administration's National Centers for Environmental Information

DYNEGY

System Not Yet Tested







Lower peak demand offsets impact of significant asset retirements

(1) Peak demand based on a 3 year average of the monthly peak from 2012 - 2014

DYNEGY

Capacity Exiting with Hurdles to New Build

Wave 1 Retirements 2010 - 2015

- Environmental regulations required significant capital investment for coal plants
- Low natural gas prices pressured economics
- ~90 GW of mostly coal-fired generation retirements throughout the U.S. (~15% of U.S. coal capacity)
- ~50 GW retire in Dynegy's key markets

Wave 2 Retirements 2016 - 2020

- Penalty regime in ISO-NE and PJM will drive marginal assets in to retirement
- 10.3 GW of existing generation did not clear PJM BRA 18/19
- 9.5 GW of demand response cleared BRA 18/19 as base which will be phased out by BRA 20/21
- 4-5 GW of additional steam units identified at risk of retirement by ISO-NE

Hurdles for New Build

- Economics don't work
- Now required to complete facilities study prior to participating in CP Auctions. Adds expense and 6 to 8 months
- Credit requirement for new-build or imports without confirmed transmission equals the greater of 50% of net CONE or $20 per MW-day (i.e. $140 per MW-day in RTO BRA 18/19 : $25 MM for 500 MW)
- Given the risk profile of CP payments, project financing becomes more challenging
- PJM estimates 75% of projects in interconnection queue will not be built

New build hype "overblown"

Moody's Revises Outlook to Positive

"...Dynegy's current B2 rating largely reflect its business and financial profile prior to the $6.25 billion acquisition of 12,400 MW of coal and gas fired assets from Duke and ECP. These acquisitions were **transformative** for Dynegy as they resulted in a substantial increase in scale, geographic diversification, and growth in the **well-developed and desirable merchant markets of PJM and ISO-NE**, resulting in an improvement in the overall business profile."

Moody's 9/25/15
Press Release

"The improved business risk profile, along with stronger than expected synergies, operating cost reductions, and supportive capacity auction results in PJM and ISO-NE **indicate stronger credit profile**."

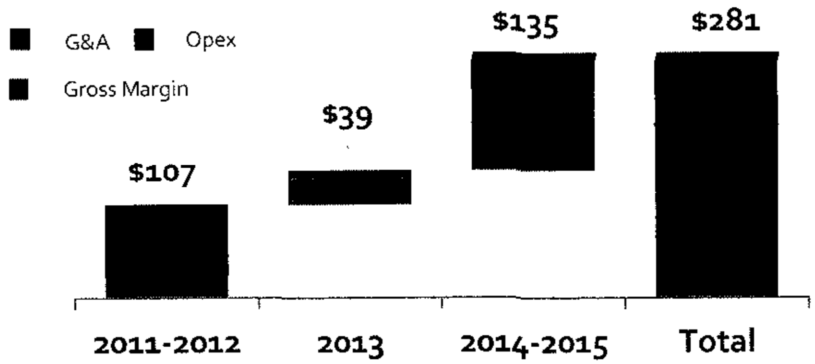
Moody's 9/25/15
Press Release

Growing the company while strengthening the balance sheet

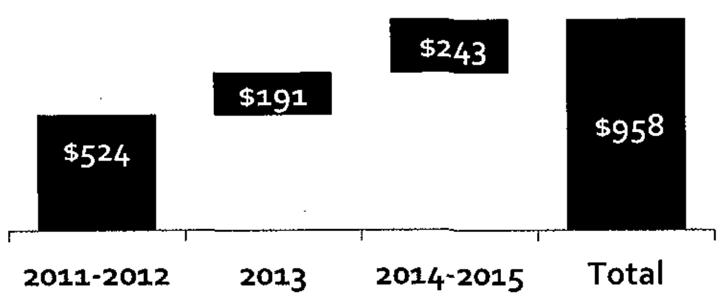
PRIDE Accelerated becomes PRIDE Energized

Historical 2011 - 2015

PRIDE EBITDA 2011 – 2015 ($ MM)

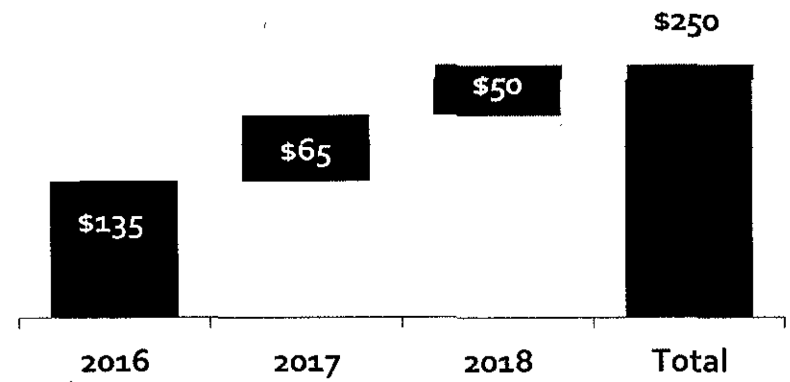


PRIDE Balance Sheet 2011 – 2015 ($ MM)

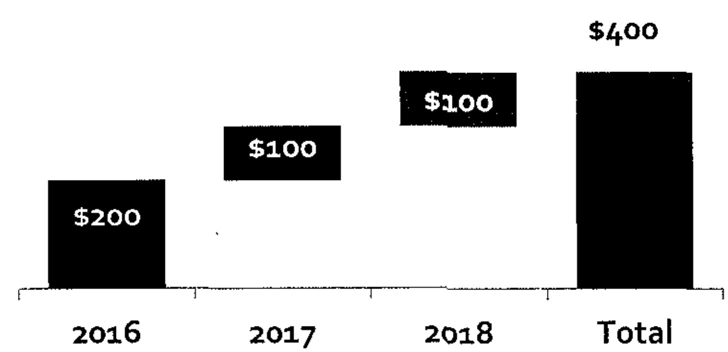


New Targets 2016 - 2018

"PRIDE Energized" EBITDA ($ MM)



"PRIDE Energized" Balance Sheet ($ MM)



PRIDE Energized to deliver an incremental $250 MM in EBITDA and $400 MM in balance sheet improvements versus 2015 over the next three years

Key Changes Since Investor Day

Equity Value Comparison

	6/24/2015	9/25/2015	Change	% Change
Shares (MM)	128	123	(5)	(4%)
Share Price	$32.71	$20.67	($12.04)	(37%)
Equity Value ($MM)	$4,187	$2,542	($1,645)	(39%)

+ **Capacity**: Positive uplift in recent PJM auctions & strong MISO pricing signals being sent
+ **Spark Spreads**: Expanding spark spreads in Dynegy's core markets
+ **Capital Allocation**: Early launch of $250 MM share repurchase program, half completed YTD
+ **PRIDE**: Next iteration of PRIDE expected to contribute $650 MM in balance sheet and EBITDA improvements over the next three years
+ **Balance Sheet**: Moody's, on 9/25/2015, revised Dynegy's rating outlook to **positive**
+ **CCR Compliance Costs**: Total cost estimates lower than Investor Day based on initial 3rd party engineering studies
- **Dark Spreads**: Decreasing forward power prices have put downward pressure on coal assets, partially offset by lower delivered coal costs

Change in equity value doesn't add up

DOE/EIA-0383(2015) | April 2015

Annual Energy Outlook 2015
with projections to 2040

U.S. Energy Information
Administration

EXHIBIT
AEP
18
PENGAD 800-631-6989

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AEO2015 is available on the EIA website at www.eia.gov/forecasts/aeo. Assumptions underlying the projections, tables of regional results, and other detailed results are available at www.eia.gov/forecasts/aeo/assumptions.

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Annual Energy Outlook 2015

With Projections to 2040

April 2015

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

This publication is on the WEB at:
www.eia.gov/forecasts/aeo

Preface

The *Annual Energy Outlook 2015* (AEO2015), prepared by the U.S. Energy Information Administration (EIA), presents long-term annual projections of energy supply, demand, and prices through 2040. The projections, focused on U.S. energy markets, are based on results from EIA's National Energy Modeling System (NEMS). NEMS enables EIA to make projections under alternative, internally-consistent sets of assumptions, the results of which are presented as cases. The analysis in AEO2015 focuses on six cases: Reference case, Low and High Economic Growth cases, Low and High Oil Price cases, and High Oil and Gas Resource case.

For the first time, the Annual Energy Outlook (AEO) is presented as a shorter edition under a newly adopted two-year release cycle. With this approach, full editions and shorter editions of the AEO will be produced in alternating years. This approach will allow EIA to focus more resources on rapidly changing energy markets both in the United States and internationally and how they might evolve over the next few years. The shorter edition of the AEO includes a more limited number of model updates, predominantly to reflect historical data updates and changes in legislation and regulation. The AEO shorter editions will include this publication, which discusses the Reference case and five alternative cases, and an accompanying *Assumptions Report*.[1] Other documentation—including documentation for each of the NEMS models and a *Retrospective Review*—will be completed only in years when the full edition of the AEO is published.

This AEO2015 report includes the following major sections:

- **Executive summary**, highlighting key results of the projections
- **Economic growth**, discussing the economic outlooks completed for each of the AEO2015 cases
- **Energy prices**, discussing trends in the markets and prices for crude oil, petroleum and other liquids,[2] natural gas, coal, and electricity for each of the AEO2015 cases
- **Delivered energy consumption by sector**, discussing energy consumption trends in the transportation, industrial, residential, and commercial sectors
- **Energy consumption by primary fuel**, discussing trends in energy consumption by fuel, including natural gas, renewables, coal, nuclear, liquid biofuels, and oil and other liquids
- **Energy intensity**, examining trends in energy use per capita, energy use per 2009 dollar of gross domestic product (GDP), and carbon dioxide (CO2) emissions per 2009 dollar of GDP
- **Energy production, imports, and exports**, examining production, import, and export trends for petroleum and other liquids, natural gas, and coal
- **Electricity generation**, discussing trends in electricity generation by fuel and prime mover for each of the AEO2015 cases
- **Energy-related CO2 emissions**, examining trends in CO2 emissions by sector and AEO2015 case.

Summary tables for the six cases are provided in Appendixes A through D. Complete tables are available in a table browser on EIA's website, at http://www.eia.gov/oiaf/aeo/tablebrowser. Appendix E provides a short discussion of the major changes adopted in AEO2015 and a brief comparison of the AEO2015 and Annual Energy Outlook 2014 results. Appendix F provides a summary of the regional formats, and Appendix G provides a summary of the energy conversion factors used in AEO2015.

The AEO2015 projections are based generally on federal, state, and local laws and regulations in effect as of the end of October 2014. The potential impacts of pending or proposed legislation, regulations, and standards (and sections of existing legislation that require implementing regulations or funds that have not been appropriated) are not reflected in the projections (for example, the proposed Clean Power Plan[3]). In certain situations, however, where it is clear that a law or a regulation will take effect shortly after AEO2015 is completed, it may be considered in the projection.

AEO2015 is published in accordance with Section 205c of the U.S. Department of Energy (DOE) Organization Act of 1977 (Public Law 95-91), which requires the EIA Administrator to prepare annual reports on trends and projections for energy use and supply.

[1]U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2015*, DOE/EIA-0554(2015) (Washington, DC, to be published), http://www.eia.gov/forecasts/aeo/assumptions.
[2]Liquid fuels (or petroleum and other liquids) include crude oil and products of petroleum refining, natural gas liquids, biofuels, and liquids derived from other hydrocarbon sources (including coal-to-liquids and gas-to-liquids).
[3]U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," *Federal Register*, pp. 34829-34958 (Washington, DC: June 18, 2014), https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.

Projections by EIA are not statements of what will happen but of what might happen, given the assumptions and methodologies used for any particular case. The AEO2015 Reference case projection is a business-as-usual trend estimate, given known technology and technological and demographic trends. EIA explores the impacts of alternative assumptions in other cases with different macroeconomic growth rates, world oil prices, and resource assumptions. The main cases in AEO2015 generally assume that current laws and regulations are maintained throughout the projections. Thus, the projections provide policy-neutral baselines that can be used to analyze policy initiatives.

While energy markets are complex, energy models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty. Some key uncertainties in the AEO2015 projections are addressed through alternative cases.

EIA has endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not a substitute for, a complete and focused analysis of public policy initiatives.

Contents

Appendixes

Tables

Figures

Executive summary

Projections in the *Annual Energy Outlook 2015* (AEO2015) focus on the factors expected to shape U.S. energy markets through 2040. The projections provide a basis for examination and discussion of energy market trends and serve as a starting point for analysis of potential changes in U.S. energy policies, rules, and regulations, as well as the potential role of advanced technologies.

Key results from the AEO2015 Reference and alternative cases include the following:

- The future path of crude oil and natural gas prices can vary substantially, depending on assumptions about the size of global and domestic resources, demand for petroleum products and natural gas (particularly in non-Organization for Economic Cooperation and Development (non-OECD) countries), levels of production, and supplies of other fuels. AEO2015 considers these factors in examining alternative price and resource availability cases.
- Growth in U.S. energy production—led by crude oil and natural gas—and only modest growth in demand reduces U.S. reliance on imported energy supplies. Energy imports and exports come into balance in the United States starting in 2028 in the AEO2015 Reference case and in 2019 in the High Oil Price and High Oil and Gas Resource cases. Natural gas is the dominant U.S. energy export, while liquid fuels[4] continue to be imported.
- Through 2020, strong growth in domestic crude oil production from tight formations leads to a decline in net petroleum imports[5] and growth in net petroleum product exports in all AEO2015 cases. In the High Oil and Gas Resource case, increased crude production before 2020 results in increased processed condensate[6] exports. Slowing growth in domestic production after 2020 is offset by increased vehicle fuel economy standards that limit growth in domestic demand. The net import share of crude oil and petroleum products supplied falls from 33% of total supply in 2013 to 17% of total supply in 2040 in the Reference case. The United States becomes a net exporter of petroleum and other liquids after 2020 in the High Oil Price and High Oil and Gas Resource cases because of greater U.S. crude oil production.
- The United States transitions from being a modest net importer of natural gas to a net exporter by 2017. U.S. export growth continues after 2017, with net exports in 2040 ranging from 3.0 trillion cubic feet (Tcf) in the Low Oil Price case to 13.1 Tcf in the High Oil and Gas Resource case.
- Growth in crude oil and dry natural gas production varies significantly across oil and natural gas supply regions and cases, forcing shifts in crude oil and natural gas flows between U.S. regions, and requiring investment in or realignment of pipelines and other midstream infrastructure.
- U.S. energy consumption grows at a modest rate over the AEO2015 projection period, averaging 0.3%/year from 2013 through 2040 in the Reference case. A marginal decrease in transportation sector energy consumption contrasts with growth in most other sectors. Declines in energy consumption tend to result from the adoption of more energy-efficient technologies and existing policies that promote increased energy efficiency.
- Growth in production of dry natural gas and natural gas plant liquids (NGPL) contributes to the expansion of several manufacturing industries (such as bulk chemicals and primary metals) and the increased use of NGPL feedstocks in place of petroleum-based naphtha[7] feedstocks.
- Rising long-term natural gas prices, the high capital costs of new coal and nuclear generation capacity, state-level policies, and cost reductions for renewable generation in a market characterized by relatively slow electricity demand growth favor increased use of renewables.
- Rising costs for electric power generation, transmission, and distribution, coupled with relatively slow growth of electricity demand, produce an 18% increase in the average retail price of electricity over the period from 2013 to 2040 in the AEO2015 Reference case. The AEO2015 cases do not include the proposed Clean Power Plan.[8]
- Improved efficiency in the end-use sectors and a shift away from more carbon-intensive fuels help to stabilize U.S. energy-related carbon dioxide (CO2) emissions, which remain below the 2005 level through 2040.

The future path of crude oil prices can vary substantially, depending on assumptions about the size of the resource and growth in demand, particularly in non-OECD countries

AEO2015 considers a number of factors related to the uncertainty of future crude oil prices, including changes in worldwide demand for petroleum products, crude oil production, and supplies of other liquid fuels. In all the AEO2015 cases, the North Sea

[4]Liquid fuels (or petroleum and other liquids) includes crude oil and products of petroleum refining, natural gas liquids, biofuels, and liquids derived from other hydrocarbon sources (including coal-to-liquids and gas-to-liquids).

[5]*Net product imports* includes trade in crude oil and petroleum products.

[6]The U.S. Department of Commerce, Bureau of Industry and Security has determined that condensate which has been processed through a distillate tower can be exported without licensing.

[7]Naphtha is a refined or semi-refined petroleum fraction used in chemical feedstocks and many other petroleum products. For a complete definition, see www.eia.gov/tools/glossary/index.cfm?id=naphtha.

[8]U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," *Federal Register*, pp. 34829-34958 (Washington, DC: June 18, 2014) https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.

Brent crude oil price reflects the world market price for light sweet crude, and all the cases account for market conditions in 2014, including the 10% decline in the average Brent spot price to $97/barrel (bbl) in 2013 dollars.

In the AEO2015 Reference case, continued growth in U.S. crude oil production contributes to a 43% decrease in the Brent crude oil price, to $56/bbl in 2015 (Figure ES1). Prices rise steadily after 2015 in response to growth in demand from countries outside the OECD; however, downward price pressure from continued increases in U.S. crude oil production keeps the Brent price below $80/bbl through 2020. U.S. crude oil production starts to decline after 2020, but increased production from non-OECD countries and from countries in the Organization of the Petroleum Exporting Countries (OPEC) contributes to the Brent price remaining below $100/bbl through 2028 and limits the Brent price increase through 2040, when it reaches $141/bbl.

There is significant price variation in the alternative cases using different assumptions. In the Low Oil Price case, the Brent price drops to $52/bbl in 2015, 7% lower than in the Reference case, and reaches $76/bbl in 2040, 47% lower than in the Reference case, largely as a result of lower non-OECD demand and higher upstream investment by OPEC. In the High Oil Price case, the Brent price increases to $122/bbl in 2015 and to $252/bbl in 2040, largely in response to significantly lower OPEC production and higher non-OECD demand. In the High Oil and Gas Resource case, assumptions about overseas demand and supply decisions do not vary from those in the Reference case, but U.S. crude oil production growth is significantly greater, resulting in lower U.S. net imports of crude oil, and causing the Brent spot price to average $129/bbl in 2040, which is 8% lower than in the Reference case.

Future natural gas prices will be influenced by a number of factors, including oil prices, resource availability, and demand for natural gas

Projections of natural gas prices are influenced by assumptions about oil prices, resource availability, and natural gas demand. In the Reference case, the Henry Hub natural gas spot price (in 2013 dollars) rises from $3.69/million British thermal units (Btu) in 2015 to $4.88/million Btu in 2020 and to $7.85/million Btu in 2040 (Figure ES2), as increased demand in domestic and international markets leads to the production of increasingly expensive resources.

In the AEO2015 alternative cases, the Henry Hub natural gas spot price is lowest in the High Oil and Gas Resource case, which assumes greater estimated ultimate recovery per well, closer well spacing, and greater gains in technological development. In the High Oil and Gas Resource case, the Henry Hub natural gas spot price falls from $3.14/million Btu in 2015 to $3.12/million Btu in 2020 (36% below the Reference case price) before rising to $4.38/million Btu in 2040 (44% below the Reference case price). Cumulative U.S. domestic dry natural gas production from 2015 to 2040 is 26% higher in the High Oil and Gas Resource case than in the Reference case and is sufficient to meet rising domestic consumption and exports—both pipeline gas and liquefied natural gas (LNG)—even as prices remain low.

Henry Hub natural gas spot prices are highest in the High Oil Price case, which assumes the same level of resource availability as the AEO2015 Reference case, but different Brent crude oil prices. The higher Brent crude oil prices in the High Oil Price case affect the level of overseas demand for U.S. LNG exports, because international LNG contracts are often linked to crude oil prices—although the linkage is expected to weaken with changing market conditions. When the Brent spot price rises in the High Oil Price case, world LNG contracts that are linked to oil prices become relatively more competitive, making LNG exports from the United States more desirable.

In the High Oil Price case, the Henry Hub natural gas spot price remains close to the Reference case price through 2020; however, higher overseas demand for U.S. LNG exports raises the average Henry Hub price to $10.63/million Btu in 2040, which is 35%

Figure ES1. North Sea Brent crude oil spot prices in four cases, 2005-40 (2013 dollars per barrel)

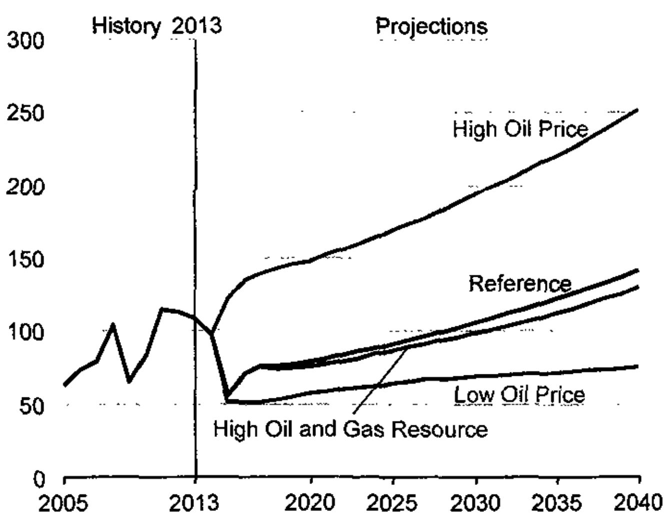
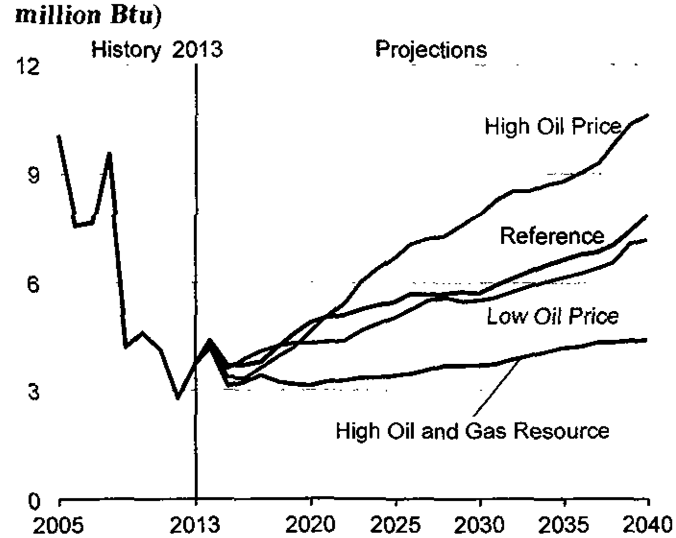


Figure ES2. Average Henry Hub spot prices for natural gas in four cases, 2005-40 (2013 dollars per million Btu)



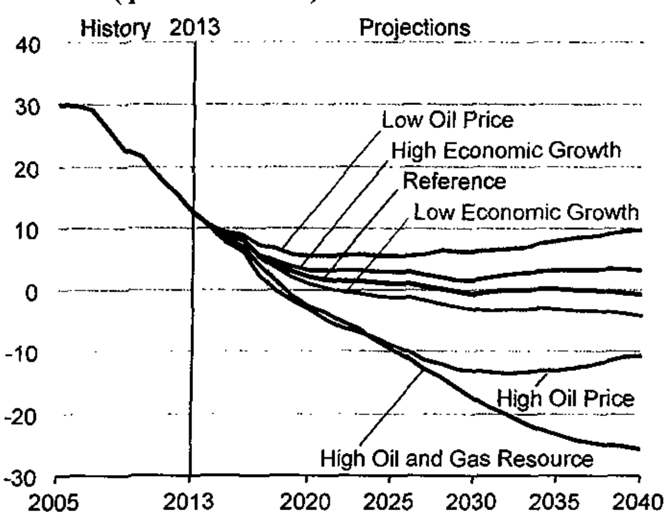
above the Reference case price. Cumulative U.S. exports of LNG from 2015 to 2040 in the High Oil Price case are more than twice those in the Reference case. The opposite occurs in the Low Oil Price case: low Brent crude oil prices cause oil-linked LNG contracts to become relatively less competitive and make U.S. LNG exports less desirable. Lower overseas demand for U.S. LNG exports causes the average Henry Hub price to reach only $7.15/million Btu in 2040, 9% lower than in the Reference case.

Global growth and trade weaken beyond 2025, creating headwinds for U.S. export-oriented industries

In the AEO2015 projections, growth in U.S. net exports contributes more to GDP growth than it has over the past 30 years (partially due to a reduction in net energy imports); however, its impact diminishes in the later years of the projection, reflecting slowing GDP growth in nations that are U.S. trading partners, along with the impacts of exchange rates and prices on trade. As economic growth in the rest of the world slows (as shown in Table ES1), so does U.S. export growth, with commensurate impacts on growth in manufacturing output, particularly in the paper, chemicals, primary metals, and other energy-intensive industries. The impact varies across industries.

Recent model revisions to the underlying industrial supply and demand relationships[9] have emphasized the importance of trade to manufacturing industries, so that the composition of trade determines the level of industrial output. Consumer goods and industrial supplies show higher levels of net export growth than other categories throughout the projection. The diminishing net export growth in all categories in the later years of the projection explains much of the leveling off of growth that occurs in some trade-sensitive industries.

Figure ES3. U.S. net energy imports in six cases, 2005-40 (quadrillion Btu)



U.S. net energy imports decline and ultimately end, largely in response to increased oil and dry natural gas production

Energy imports and exports come into balance in the United States in the AEO2015 Reference case, starting in 2028. In the High Oil Price and High Oil and Gas Resource cases, with higher U.S. crude oil and dry natural gas production and lower imports, the United States becomes a net exporter of energy in 2019. In contrast, in the Low Oil Price case, the United States remains a net energy importer through 2040 (Figure ES3).

Economic growth assumptions also affect the U.S. energy trade balance. In the Low Economic Growth case, U.S. energy imports are lower than in the Reference case, and the United States becomes a net energy exporter in 2022. In the High Economic Growth case, the United States remains a net energy importer through 2040.

The share of total U.S. energy production from crude oil and lease condensate rises from 19% in 2013 to 25% in 2040 in the High Oil and Gas Resource case, as compared with no

Table ES1. Growth of trade-related factors in the Reference case, 1983-2040 (average annual percent change)

Measure	History: 1983-2013	2013-20	2020-25	2025-30	2030-35	2035-40
U.S. GDP	2.8%	2.6%	2.5%	2.3%	2.2%	2.3%
U.S. GDP per capita	1.8%	1.8%	1.8%	1.6%	1.6%	1.8%
U.S. exports	6.1%	4.8%	6.2%	4.8%	4.5%	4.1%
U.S. imports	6.0%	4.6%	4.1%	3.7%	3.7%	3.7%
U.S. net export growth	0.1%	0.3%	2.1%	1.1%	0.8%	0.3%
Real GDP of OECD trading partners	2.4%	2.1%	1.9%	1.8%	1.7%	1.7%
Real GDP of other trading partners	4.7%	4.3%	4.2%	3.7%	3.4%	3.2%

Note: Major U.S. trading partners include Australia, Canada, Switzerland, United Kingdom, Japan, Sweden, and the Eurozone. Other U.S. trading partners include Argentina, Brazil, Chile, Columbia, Mexico, Hong Kong, Indonesia, India, Israel, South Korea, Malaysia, Philippines, Russia, Saudi Arabia, Singapore, Thailand, Taiwan, and Venezuela.

[9]AEO2015 incorporates the U.S. Bureau of Economic Analysis (BEA) updated 2007 input-output table, released at the end of December 2013. See U.S. Department of Commerce, Bureau of Economic Analysis, "Industry Economic Accounts Information Guide (Washington, DC: December 18, 2014), http://www.bea.gov/industry/iedguide.htm#aia.

change in the Reference case. Dry natural gas production remains the largest contributor to total U.S. energy production through 2040 in all the AEO2015 cases, with a higher share in the High Oil and Gas Resource case (38%) than in the Reference case (34%) and all other cases. In 2013, dry natural gas accounted for 30% of total U.S. energy production.

Coal's share of total U.S. energy production in the High Oil and Gas Resource case falls from 26% in 2013 to 15% in 2040. In the Reference case and most of the other AEO2015 cases, the coal share remains slightly above 20% of total U.S. energy production through 2040; in the Low Oil Price case, with lower oil and gas production levels, it remains essentially flat at 23% through 2040.

Continued strong growth in domestic production of crude oil from tight formations leads to a decline in net imports of crude oil and petroleum products

U.S. crude oil production from tight formations leads the growth in total U.S. crude oil production in all the AEO2015 cases. In the Reference case, lower levels of domestic consumption of liquid fuels and higher levels of domestic production of crude oil push the net import share of crude oil and petroleum products supplied down from 33% in 2013 to 17% in 2040 (Figure ES4).

In the High Oil Price and High Oil and Gas Resource cases, growth in tight oil production results in significantly higher levels of total U.S. crude oil production than in the Reference case. Crude oil production in the High Oil and Gas Resource case increases to 16.6 million barrels per day (bbl/d) in 2040, compared with a peak of 10.6 million bbl/d in 2020 in the Reference case. In the High Oil Price case, production reaches a high of 13.0 million bbl/d in 2026, then declines to 9.9 million bbl/d in 2040 as a result of earlier resource development. In the Low Oil Price case, U.S. crude oil production totals 7.1 million bbl/d in 2040. The United States becomes a net petroleum exporter in 2021 in both the High Oil Price and High Oil and Gas Resource cases. With lower levels of domestic production and higher domestic consumption in the Low Oil Price case, the net import share of total liquid fuels supply increases to 36% of total domestic supply in 2040.

Net natural gas trade, including LNG exports, depends largely on the effects of resource levels and oil prices

In all the AEO2015 cases, the United States transitions from a net importer of 1.3 Tcf of natural gas in 2013 (5.5% of the 23.7 Tcf delivered to consumers) to a net exporter in 2017. Net exports continue to grow after 2017, to a 2040 range between 3.0 Tcf in the Low Oil Price case and 13.1 Tcf in the High Oil and Gas Resource case (Figure ES5).

In the Reference case, LNG exports reach 3.4 Tcf in 2030 and remain at that level through 2040, when they account for 46% of total U.S. natural gas exports. The growth in U.S. LNG exports is supported by differences between international and domestic natural gas prices. LNG supplied to international markets is primarily priced on the basis of world oil prices, among other factors. This results in significantly higher prices for global LNG than for domestic natural gas supply, particularly in the near term. However, the relationship between the price of international natural gas supplies and world oil prices is assumed to weaken later in the projection period, in part as a result of growth in U.S. LNG export capacity. U.S. natural gas prices are determined primarily by the availability and cost of domestic natural gas resources.

In the High Oil Price case, with higher world oil prices resulting in higher international natural gas prices, U.S. LNG exports climb to 8.1 Tcf in 2033 and account for 73% of total U.S. natural gas exports in 2040. In the High Oil and Gas Resource case, abundant U.S. dry natural gas production keeps domestic natural gas prices lower than international prices, supporting the growth of U.S. LNG exports, which total 10.3 Tcf in 2037 and account for 66% of total U.S. natural gas exports in 2040. In the Low Oil Price case,

Figure ES4. Net crude oil and petroleum product imports as a percentage of U.S. product supplied in four cases, 2005-40 (percent)

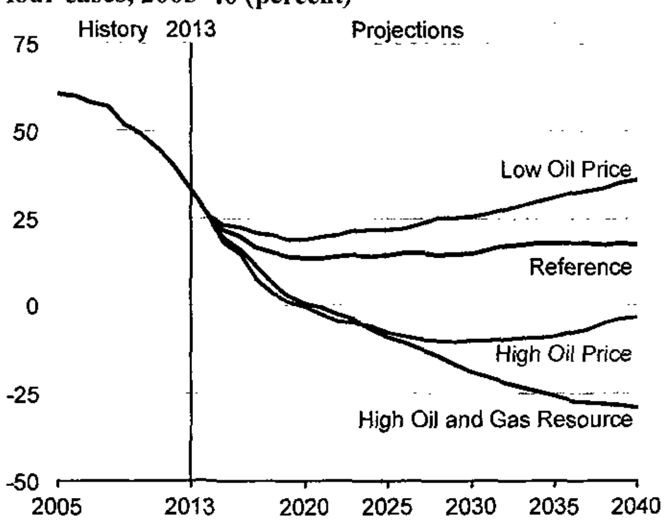
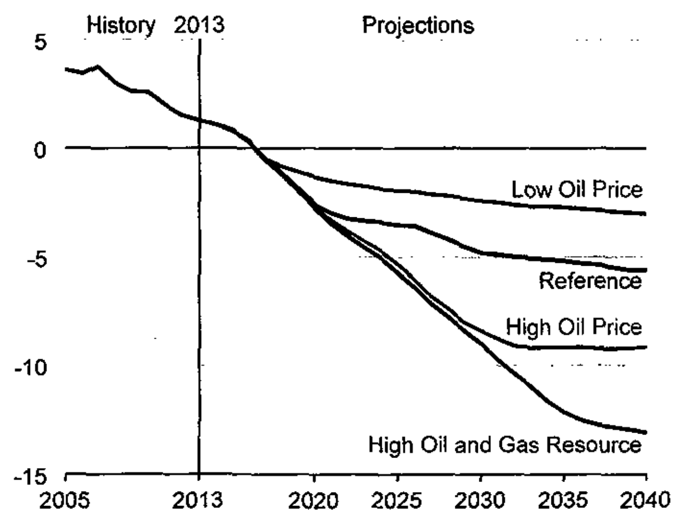


Figure ES5. U.S. total net natural gas imports in four cases, 2005-40 (trillion cubic feet)



with lower world oil prices, U.S. LNG exports are less competitive and grow more slowly, to a peak of 0.8 Tcf in 2018, and account for 13% of total U.S. natural gas exports in 2040.

Additional growth in net natural gas exports comes from growing natural gas pipeline exports to Mexico, which reach a high of 4.7 Tcf in 2040 in the High Oil and Gas Resource case (compared with 0.7 Tcf in 2013). In the High Oil Price case, U.S. natural gas pipeline exports to Mexico peak at 2.2 Tcf in 2040, as higher domestic natural gas prices resulting from increased world demand for LNG reduce the incentive to export natural gas via pipeline. Natural gas pipeline net imports from Canada remain below 2013 levels through 2040 in all the AEO2015 cases, but these imports do increase in response to higher natural gas prices in the latter part of the projection period.

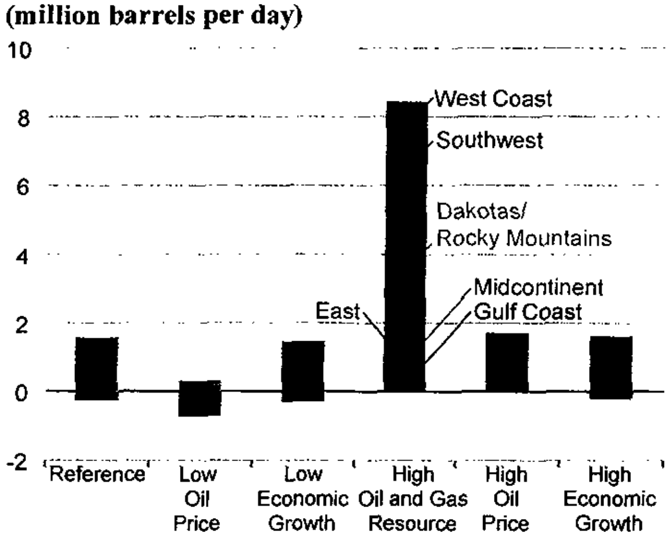
Regional variations in domestic crude oil and dry natural gas production can force significant shifts in crude oil and natural gas flows between U.S. regions, requiring investment in or realignment of pipelines and other midstream infrastructure

U.S. crude oil and dry natural gas production levels have increased rapidly in recent years. From 2008 to 2013, crude oil production grew from 5.0 million bbl/d to 7.4 million bbl/d, and annual dry natural gas production grew from 20.2 Tcf to 24.3 Tcf. All the AEO2015 cases project continued growth in U.S. dry natural gas production, whereas crude oil production continues to increase but eventually declines in all cases except the High Oil and Gas Resource case. In most of the cases, Lower 48 onshore crude oil production shows the strongest growth in the Dakotas/Rocky Mountains region (which includes the Bakken formation), followed by the Southwest region (which includes the Permian Basin) (Figure ES6). The strongest growth of dry natural gas production in the Lower 48 onshore in most of the AEO2015 cases occurs in the East region (which includes the Marcellus Shale and Utica Shale), followed by the Gulf Coast onshore region and the Dakotas/Rocky Mountains region. Interregional flows to serve downstream markets vary significantly among the different cases.

In the High Oil Price case, higher prices for crude oil and increased demand for LNG support higher levels of Lower 48 onshore crude oil and dry natural gas production than in the Reference case. Production in the High Oil Price case is exceeded only in the High Oil and Gas Resource case, where greater availability of oil and natural gas resources leads to more rapid production growth. The higher production levels in the High Oil Price and High Oil and Gas Resource cases are sustained through the entire projection period. Onshore Lower 48 crude oil production in 2040 drops below its 2013 level only in the Low Oil Price case, which also shows the lowest growth of dry natural gas production.

Crude oil imports into the East Coast and Midwest Petroleum Administration for Defense Districts (PADDs) 1 and 2 grow from 2013 to 2040 in all cases except the High Oil and Gas Resource case. All cases, including the High Oil and Gas Resource case, maintain significant crude oil imports into the Gulf Coast (PADD 3) and West Coast (PADD 5) through 2040. The Dakotas/Rocky Mountains (PADD 4) has significant crude oil imports only through 2040 in the High Oil Price case. The high levels of crude oil imports in all cases except the High Oil and Gas Resource case support growing levels of gasoline, diesel, and jet fuel exports as U.S. refineries continue to have a competitive advantage over refineries in the rest of the world. The High Oil and Gas Resource case is the only case with significant crude oil exports, which occur as a result of additional crude oil exports to Canada. The High Oil and Gas Resource case also shows significantly higher amounts of natural gas flowing out of the Mid-Atlantic and Dakotas/ Rocky Mountains regions than most other cases, and higher LNG exports out of the Gulf Coast than any other case.

Figure ES6. Change in U.S. Lower 48 onshore crude oil production by region in six cases, 2013-40 (million barrels per day)



U.S. energy consumption grows at a modest rate over the projection with reductions in energy intensity resulting from improved technologies and from policies in place

U.S. energy consumption grows at a relatively modest rate over the AEO2015 projection period, averaging 0.3%/ year from 2013 through 2040 in the Reference case. The transportation and residential sector's decreases in energy consumption (less than 2% over the entire projection period) contrast with growth in other sectors. The strongest energy consumption growth is projected for the industrial sector, at 0.7%/year. Declines in energy consumption tend to result from the adoption of more energy-efficient technologies and policies that promote energy efficiency. Increases tend to result from other factors, such as economic growth and the relatively low energy prices that result from an abundance of supplies.

Near-zero growth in energy consumption is a relatively recent phenomenon, and substantial uncertainty is associated with specific aspects of U.S. energy consumption in the AEO2015 projections. This uncertainty is especially relevant as the United States continues to recover from the latest economic recession and resumes more normal economic growth. Although demand for energy often grew with economic recoveries during the second half of the 20th century, technology and policy factors currently are acting in combination to dampen growth in energy consumption.

The AEO2015 alternative cases demonstrate these dynamics. The High and Low Economic Growth cases project higher and lower levels of travel demand, respectively, and of energy consumption growth, while holding policy and technology assumptions constant. In the High Economic Growth case and the High Oil and Gas Resource case, energy consumption growth (0.6%/year and 0.5%/year, respectively) is higher than in the Reference case. Energy consumption growth in the Low Economic Growth case is lower than in the Reference case (nearly flat). In the High Oil Price case, it is higher than in the Reference case, at 0.5%/year, mainly as a result of increased domestic energy production and more consumption of diesel fuel for freight transportation and trucking.

In the AEO2015 Reference case, as a result of increasingly stringent fuel economy standards, gasoline consumption in the transportation sector in 2040 is 21% lower than in 2013. In contrast, diesel fuel consumption, largely for freight transportation and trucking, grows at an average rate of 0.8%/year from 2013 to 2040, as economic growth results in more shipments of goods. Because the United States consumes more gasoline than diesel fuel, the pattern of gasoline consumption strongly influences the overall trend of energy consumption in the transportation sector (Figure ES7).

Industrial energy use rises with growth of shale gas supply

Production of dry natural gas and natural gas plant liquids (NGPL) in the United States has increased markedly over the past few years, and the upward production trend continues in the AEO2015 Reference, High Oil Price, and High Oil and Gas Resource cases, with the High Oil and Gas Resource case showing the strongest growth in production of both dry natural gas and NGPL. Sustained high levels of dry natural gas and NGPL production at prices that are attractive to industry in all three cases contribute to the growth of industrial energy consumption over the 2013-40 projection period and expand the range of fuel and feedstock choices.

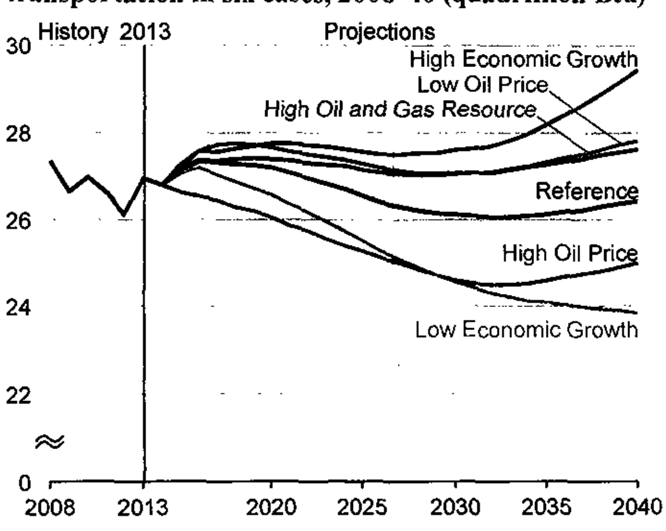
Increased supply of natural gas from shale resources and the associated liquids contributes to lower prices for natural gas and hydrocarbon gas liquids (HGL), which support higher levels of industrial output. The energy-intensive bulk chemicals industry benefits from lower prices for fuel (primarily natural gas) and feedstocks (natural gas and HGL), as consumption of natural gas and HGL feedstocks increases by more than 50% from 2013 to 2040 in the Reference case, mostly as a result of growth in the total capacity of U.S. methanol, ammonia (mostly for nitrogenous fertilizers), and ethylene catalytic crackers. Increased availability of HGL leads to much slower growth in the use of heavy petroleum-based naphtha feedstocks compared to the lighter HGL feedstocks (ethane, propane, and butane). With sustained low HGL prices, the feedstock slate continues to favor HGL at unprecedented levels.

Other energy-intensive industries, such as primary metals and pulp and paper, also benefit from the availability and pricing of dry natural gas production from shale resources. However, factors other than lower natural gas and HGL prices, such as changes in nonenergy costs and export demand, also play significant roles in increasing manufacturing output.[10]

Manufacturing gross output in the High Oil and Gas Resource case is only slightly higher than in the Reference case, and most of the difference in industrial natural gas use between the two cases is attributable to the mining industry—specifically, oil and gas extraction. With increased extraction activity in the High Oil and Gas Resource case, natural gas consumption for lease and plant use in 2040 is 1.6 quadrillion Btu (68%) higher than in the Reference case.

Increased production of dry natural gas from shale resources (e.g., as seen in the High Oil and Gas Resource case relative to the Reference case) leads to a lower natural gas price, which leads to more natural gas use for combined heat and power (CHP) generation in the industrial sector. In 2040, natural gas use for CHP generation is 12% higher in the High Oil and Gas Resource case than in the Reference case, reflecting the higher levels of dry natural gas production. Finally, the increased supply of dry natural gas from shale resources leads to the increased use of natural gas to meet heat and power needs in the industrial sector.

Figure ES7. Delivered energy consumption for transportation in six cases, 2008-40 (quadrillion Btu)



Renewables meet much of the growth in electricity demand

Renewable electricity generation in the AEO2015 Reference case increases by 72% from 2013 to 2040, accounting for more than one-third of new generation capacity. The renewable share of total generation grows from 13% in 2013

[10] E. Sendich, "The Importance of Natural Gas in the Industrial Sector With a Focus on Energy-Intensive Industries," EIA Working Paper (February 28, 2014), http://www.eia.gov/workingpapers/pdf/natgas_indussector.pdf.

to 18% in 2040. Federal tax credits and state renewable portfolio standards that do not expire (sunset) continue to drive the relatively robust near-term growth of nonhydropower renewable sources, with total renewable generation increasing by 25% from 2013 to 2018. However, from 2018 through about 2030, the growth of renewable capacity moderates, as relatively slow growth of electricity demand reduces the need for new generation capacity. In addition, the combination of relatively low natural gas prices and the expiration of several key federal and state policies results in a challenging economic environment for renewables. After 2030, renewable capacity growth again accelerates, as natural gas prices increase over time and renewables become increasingly cost-competitive in some regions.

Wind and solar generation account for nearly two-thirds of the increase in total renewable generation in the AEO2015 Reference case. Solar photovoltaic (PV) technology is the fastest-growing energy source for renewable generation, at an annual average rate of 6.8%. Wind energy accounts for the largest absolute increase in renewable generation and for 40.0% of the growth in renewable generation from 2013 to 2038, displacing hydropower and becoming the largest source of renewable generation by 2040. PV capacity accounts for nearly all the growth in solar generation, split between the electric power sector and the end-use sectors (e.g., distributed or customer-sited generation). Geothermal generation grows at an average annual rate of about 5.5% over the projection period, but because geothermal resources are concentrated geographically, the growth is limited to the western United States. Biomass generation increases by an average of 3.1%/year, led by cofiring at existing coal plants through about 2030. After 2030, new dedicated biomass plants account for most of the growth in generation from biomass energy sources.

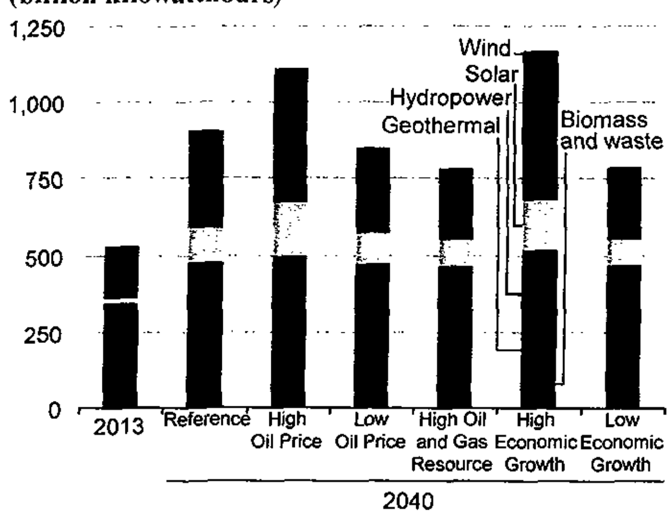
In the High Economic Growth and High Oil Price cases, renewable generation growth exceeds the levels in the Reference case—more than doubling from 2013 to 2040 in both cases (Figure ES8), primarily as a result of increased demand for new generation capacity in the High Economic Growth case and relatively more expensive competing fuel prices in the High Oil Price case. In the Low Economic Growth and Low Oil Price cases, with slower load growth and lower natural gas prices, the overall increase in renewable generation from 2013 to 2040 is somewhat smaller than in the Reference case but still grows by 49% and 61%, respectively, from 2013 to 2040. Wind and solar PV generation in the electric power sector, the sector most affected by renewable electric generation, account for most of the variation across the alternative cases in the later years of the projections.

Electricity prices increase with rising fuel costs and expenditures on electric transmission and distribution infrastructure

In the AEO2015 Reference case, increasing costs of electric power generation and transmission and distribution, coupled with relatively slow growth of electricity sales (averaging 0.7%/year), result in an 18% increase in the average retail price of electricity (in real 2013 dollars) over the projection period. In the Reference case, prices increase from 10.1 cents/kilowatthour (kWh) in 2013 to 11.8 cents/kWh in 2040. In comparison, over the same period, the largest increase in retail electricity prices (28%) is in the High Oil Price case (to 12.9 cents/kWh in 2040), and the smallest increase (2%) is in the High Oil and Gas Resource case (to 10.3 cents/kWh in 2040). Electricity prices are determined by economic conditions, efficiency of energy use, competitiveness of electricity supply, investment in new generation capacity, investment in transmission and distribution infrastructure, and the costs of operating and maintaining plants in service. Those factors vary in the alternative cases.

Fuel costs (mostly for coal and natural gas) account for the largest portion of generation costs in consumer electricity bills. In 2013, coal accounted for 44% and natural gas accounted for 42% of the total fuel costs for electricity generation. In the AEO2015 Reference case, coal accounts for 35% and natural gas for 55% of total fuel costs in 2040. Coal prices rise on average by 0.8% per year and natural gas prices by 2.4%/year in the Reference case, compared with 1.3%/year and 3.1%/year, respectively, in the High Oil Price case and 0.5%/year and 0.2%/year, respectively, in the High Oil and Gas Resource case.

Figure ES8. Total U.S. renewable generation in all sectors by fuel in six cases, 2013 and 2040 (billion kilowatthours)



There has been a fivefold increase in investment in new electricity transmission capacity in the United States since 1997, as well as large increases in spending for distribution capacity. Although investments in new transmission and distribution capacity do not continue at the same rates in AEO2015, spending continues on additional transmission and distribution capacity to connect to new renewable energy sources; improvements in the reliability and resiliency of the grid; enhancements to community aesthetics (underground lines); and smart grid construction.

The average annual rate of growth in U.S. electricity use (including sales and direct use) has slowed from 9.8% in the 1950s to 0.5% over the past decade. Factors contributing to the lower rate of growth include slower population growth, market saturation of electricity-intensive appliances, improvements in the efficiency of household appliances, and a shift in the economy toward a larger share of consumption in less energy-intensive industries. In the AEO2015 Reference case, U.S. electricity use grows by an average of 0.8%/year from 2013 to 2040.

Energy-related CO2 emissions stabilize with improvements in the energy intensity and carbon intensity of electricity generation

U.S. energy-related CO2 emissions in 2013 totaled 5,405 million metric tons (mt).[11] In the AEO2015 Reference case, CO2 emissions increase by 144 million mt (2.7%) from 2013 to 2040, to 5,549 million mt—still 444 million mt below the 2005 level of 5,993 million mt. Among the AEO2015 alternative cases, total emissions in 2040 range from a high of 5,979 million mt in the High Economic Growth case to a low of 5,160 million mt in the Low Economic Growth case.

In the Reference case:

- CO2 emissions from the electric power sector increase by an average of 0.2%/year from 2013 to 2040, as a result of relatively slow growth in electricity sales (averaging 0.7%/year) and increasing substitution of lower-carbon fuels, such as natural gas and renewable energy sources, for coal in electricity generation.
- CO2 emissions from the transportation sector decline by an average of 0.2%/year, with overall improvements in vehicle energy efficiency offsetting increased travel demand, growth in diesel consumption in freight trucks, and consumer's preference for larger, less-efficient vehicles as a result of the lower fuel prices that accompany strong growth of domestic oil and dry natural gas production.
- CO2 emissions from the industrial sector increase by an average of 0.5%/year, reflecting a resurgence of industrial activity fueled by low energy prices, particularly for natural gas and HGL feedstocks in the bulk chemical sector.
- CO2 emissions from the residential sector decline by an average of 0.2%/year, with improvements in appliance and building shell efficiencies more than offsetting growth in housing units.
- CO2 emissions from the commercial sector increase by an average of 0.3%/year even with improvements in equipment and building shell efficiency, as a result of increased electricity consumption resulting from the growing proliferation of data centers and electric devices, such as networking equipment and video displays, as well as greater use of natural gas-fueled combined heat and power distributed generation.

[11]Based on EIA, Monthly Energy Review (November 2014), and reported here for consistency with data and other calculations in the AEO2015 tables. The 2013 total was subsequently updated to 5,363 million metric tons in EIA's February 2015 Monthly Energy Review, DOE/EIA-0035(2015/02), http://www.eia.gov/totalenergy/data/monthly/archive/00351502.pdf.

Introduction

In preparing the *Annual Energy Outlook 2015* (AEO2015)—a shorter edition; see text box on page 2—the U.S. Energy Information Administration (EIA) evaluated a range of trends and issues that could have major implications for U.S. energy markets. This report presents the AEO2015 Reference case and compares it with five alternative cases (Low and High Oil Price, Low and High Economic Growth, and High Oil and Gas Resource) that were completed as part of AEO2015 (see Appendixes A, B, C, and D).

Because of the uncertainties inherent in any energy market projection, the Reference case results should not be viewed in isolation. Readers are encouraged to review the alternative cases to gain perspective on how variations in key assumptions can lead to different outlooks for energy markets. In addition to the alternative cases prepared for AEO2015, EIA has examined many proposed policies affecting energy markets over the past few years. Reports describing the results of those analyses are available on EIA's website.[12]

Table 1 provides a summary of the six cases produced as part of AEO2015. For each case, the table gives the name used in AEO2015 and a brief description of the major assumptions underlying the projections. Regional results and other details of the projections are available at http://www.eia.gov/forecasts/aeo/tables_ref.cfm#supplement.

Table 1. Summary of AEO2015 cases

Case name	Description
Reference	Real gross domestic product (GDP) grows at an average annual rate of 2.4% from 2013 to 2040, under the assumption that current laws and regulations remain generally unchanged throughout the projection period. North Sea Brent crude oil prices rise to $141/barrel (bbl) (2013 dollars) in 2040. Complete projection tables are provided in Appendix A.
Low Economic Growth	Real GDP grows at an average annual rate of 1.8% from 2013 to 2040. Other energy market assumptions are the same as in the Reference case. Partial projection tables are provided in Appendix B.
High Economic Growth	Real GDP grows at an average annual rate of 2.9% from 2013 to 2040. Other energy market assumptions are the same as in the Reference case. Partial projection tables are provided in Appendix B.
Low Oil Price	Low oil prices result from a combination of low demand for petroleum and other liquids in nations outside the Organization for Economic Cooperation and Development (non-OECD nations) and higher global supply. On the supply side, the Organization of Petroleum Exporting Countries (OPEC) increases its liquids market share from 40% in 2013 to 51% in 2040, and the costs of other liquids production technologies are lower than in the Reference case. Light, sweet (Brent) crude oil prices remain around $52/bbl (2013 dollars) through 2017, and then rise slowly to $76/bbl in 2040. Other energy market assumptions are the same as in the Reference case. Partial projection tables are provided in Appendix C.
High Oil Price	High oil prices result from a combination of higher demand for liquid fuels in non-OECD nations and lower global crude oil supply. OPEC's liquids market share averages 32% throughout the projection. Non-OPEC crude oil production expands more slowly in short- to mid-term relative to the Reference case. Brent crude oil prices rise to $252/bbl (2013 dollars) in 2040. Other energy market assumptions are the same as in the Reference case. Partial projection tables are provided in Appendix C.
High Oil and Gas Resource	Estimated ultimate recovery (EUR) per shale gas, tight gas, and tight oil well is 50% higher and well spacing is 50% closer (i.e., the number of wells drilled is 100% higher) than in the Reference case. In addition, tight oil resources are added to reflect new plays or the expansion of known tight oil plays, and the EUR for tight and shale wells increases by 1%/year more than the annual increase in the Reference case to reflect additional technology improvements. This case also includes kerogen development; undiscovered resources in the offshore Lower 48 states and Alaska; and coalbed methane and shale gas resources in Canada that are 50% higher than in the Reference case. Other energy market assumptions are the same as in the Reference case. Partial projection tables are provided in Appendix D.

[12]See "Congressional and other requests," http://www.eia.gov/analysis/reports.cfm?t=138.

Changes in release cycle for EIA's *Annual Energy Outlook*

To focus more resources on rapidly changing energy markets and the ways in which they might evolve over the next few years, the U.S. Energy Information Administration (EIA) is revising the schedule and approach for production of the *Annual Energy Outlook* (AEO). Starting with this *Annual Energy Outlook 2015* (AEO2015), EIA is adopting a two-year release cycle for the AEO, with full and shorter editions of the AEO produced in alternating years. AEO2015 is a shorter edition of the AEO.

The shorter AEO includes a limited number of model updates, which are selected predominantly to reflect historical data updates and changes in legislation and regulations. A complete listing of the changes made for AEO2015 is shown in Appendix E. The shorter edition includes a Reference case and five alternative cases: Low Oil Price, High Oil Price, Low Economic Growth, High Economic Growth, and High Oil and Gas Resource.

The shorter AEO will include this publication, which discusses the Reference case and alternative cases, as well as the report, *Assumptions to the Annual Energy Outlook 2015.*[13] Other documentation—including model documentation for each of the National Energy Modeling System (NEMS) models and the *Retrospective Review*—will be completed only for the years when a full edition of the AEO is produced.

To provide a basis against which alternative cases and policies can be compared, the AEO Reference case generally assumes that current laws and regulations affecting the energy sector remain unchanged throughout the projection (including the assumption that laws that include sunset dates do, in fact, expire at the time of those sunset dates). This assumption enables policy analysis with less uncertainty regarding unstated legal or regulatory assumptions.

Economic growth

The AEO economic forecasts are trend projections, with no major shocks assumed and with potential growth determined by the economy's supply capability. Growth in aggregate supply depends on increases in the labor force, growth of capital stocks, and improvements in productivity. Long-term demand growth depends on labor force growth, income growth, and population growth. The AEO2015 Reference case uses the U.S. Census Bureau's December 2012 middle population projection: U.S. population grows at an average annual rate of 0.7%, real GDP at 2.4%, labor force at 0.6%, and nonfarm labor productivity at 2.0% from 2013 to 2040.

Table 2. Growth in key economic factors in historical data and in the Reference case

	AEO2015 (2013-40)	Previous 30 Years
Real 2009 dollars (annual average percent change)		
GDP	2.4	2.8
GDP per capita	1.7	1.8
Disposable income	2.5	2.9
Consumer spending	2.4	3.1
Private investment	3.0	3.5
Exports	4.9	6.1
Imports	4.0	6.0
Government expenditures	0.9	1.7
GDP: Major trading countries	1.9	2.4
GDP: Other trading countries	3.8	4.7
Average annual rate		
Federal funds rate	3.2	4.5
Unemployment rate	5.3	6.3
Nonfarm business output per hour	2.0	2.0

Source: AEO2015 Reference case D021915a, based on IHS Global Insight T301114.wf1.

Table 2 compares key long-run economic growth projections in AEO2015 with actual growth rates over the past 30 years. In the AEO2015 Reference case, U.S. real GDP grows at an average annual rate of 2.4% from 2013 to 2040—a rate that is 0.4 percentage points slower than the average over the past 30 years. GDP expands in the Reference case by 3.1% in 2015, 2.5% in 2016, 2.6% from 2015 to 2025, and 2.4% from 2015 to 2040. As a share of GDP, consumption expenditures account for more than two-thirds of total GDP. In terms of growth, it is exports and business fixed investment that contribute the most to GDP. Growth in these is relatively strong during the first 10 years of the projection and then moderates for the remaining years. The growth rates for both exports and business fixed investment are above the rate of GDP growth with exports dominating throughout the projection (Figure 1).

In the AEO2015 Reference case, nominal interest rates over the 2013-40 period are generally lower than those observed for the preceding 30 years, based on an expectation of lower inflation rates in the projection period. At present, the term structure of interest rates is still at the lowest level seen over the past 40 years. In 2012, the federal funds rate averaged 0.1%. Longer-term nominal interest rates are projected to average around 6.0%, which is lower than the previous 30-year average of 7.8%. After 2015, interest rates in ensuing

[13]U.S. Energy Information Administration, Assumptions to the Annual Energy Outlook 2015, DOE/EIA-0554(2015) (Washington, DC, to be published), http://www.eia.gov/forecasts/aeo/assumptions.

five-year periods through 2040 are expected to stabilize at a slightly higher level than the five-year averages through 2013, 2014, and 2015, as the result of a modest inflation rate.

Appreciation in the U.S. dollar exchange rate dampens export growth during the first five years of the projections; however, the dollar is expected to depreciate relative to the currencies of major U.S. trading partners after 2020, which combined with modest growth in unit labor costs stimulates U.S. export growth toward the end of the projection, eventually improving the U.S. current account balance. Real exports of goods and services grow at an average annual rate of 4.9%—and real imports of goods and services grow at an average annual rate of 4.0%—from 2013 to 2040 in the Reference case. The inflation rate, as measured by growth in the Consumer Price Index (CPI), averages 2.0% from 2013 to 2040 in the Reference case, compared with the average annual CPI inflation rate of 2.9% from 1983 to 2013.

Annual growth in total gross output of all goods and services, which includes both final and intermediate products, averages 1.9%/year from 2013 to 2040, with growth in the service sector (1.9%/year) just below manufacturing growth (2.0%/year) over the long term. In 2040, the manufacturing share of total gross output (17%) rises slightly above the 2013 level (16%) in the AEO2015 Reference case.

Total industrial production (which includes manufacturing, construction, agriculture, and mining) grows by 1.8%/year from 2013 to 2040 in the AEO2015 Reference case, with slower growth in key manufacturing industries, such as paper, primary metals, and aspects of chemicals excluding the plastic resin and pharmaceutical industries. Except for trade of industrial supplies, which mostly affect energy-intensive industries, net exports show weak growth until 2020. After 2020, export growth recovers as the dollar begins to depreciate and the economic growth of trading partners continues. Net export growth is strongest from the late 2020s through 2034 and declines from 2035 to 2040.

Updated information on how industries supply other industries and meet the demand of different types of GDP expenditures has influenced certain industrial projections.[14] For example, as a result of a better understanding of how the pulp and paper industry supplies other industries, trade of consumer goods and industrial supplies has a greater effect on production in the pulp and paper industry. Nonenergy-intensive manufacturing industries show higher growth than total industrial production, primarily as a result of growth in metal-based durables (Figure 2).

In the AEO2015 Reference case, manufacturing output goes through two distinct growth periods, with the clearest difference between periods seen in the energy-intensive industries. Stronger growth in U.S. manufacturing through 2025 results in part from increased shale gas production, which affects U.S. competitiveness and also results in higher GDP growth early in the projection period. In the Reference case, manufacturing output grows at an average annual rate of 2.3% from 2013 to 2025. After 2025, growth slows to 1.7% as a result of increased foreign competition and rising energy prices, with energy-intensive, trade-exposed industries showing the largest drop in growth. The energy-intensive industries grow at average rates of 1.8%/year from 2013 to 2025 and 0.7%/year from 2025 to 2040. Growth rates in the sector are uneven, with pulp and paper output decreasing at an average annual rate of 0.1% and the cement industry growing at an average annual rate of 3.1% from 2013 to 2040.

Figure 1. Annual changes in U.S. gross domestic product, business investment, and exports in the Reference case, 2015-40 (percent)

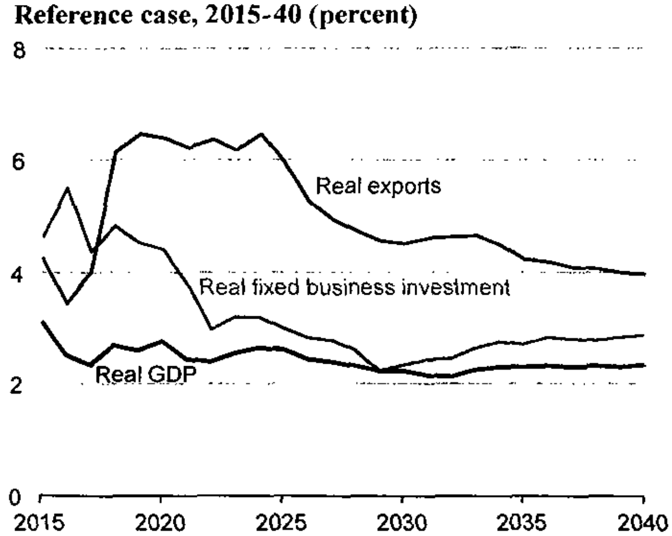
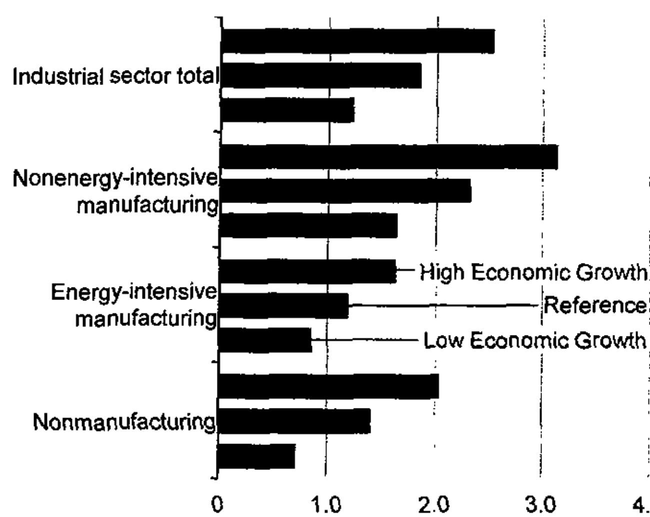


Figure 2. Annual growth rates for industrial output in three cases, 2013-40 (percent per year)



[14]The Industrial Output Model of the NEMS Macroeconomic Activity Module now uses the Bureau of Economic Analysis detailed input-output (IO) matrices for 2007 rather than 2002 (http://bea.gov/industry/io_annual.htm) and also now incorporates information from the aggregate IO matrices (http://bea.gov/industry/gdpbyind_data.htm).

AEO2015 presents three economic growth cases: Reference, High, and Low. The High Economic Growth case assumes higher growth and lower inflation, compared with the Reference case, and the Low Economic Growth case assumes lower growth and higher inflation. Differences among the Reference, High Economic Growth, and Low Economic Growth cases reflect different expectations for growth in population (specifically, net immigration), labor force, capital stock, and productivity, which are above trend in the High Economic Growth case and below trend in the Low Economic Growth case. The average annual growth rate for real GDP from 2013 to 2040 in the Reference case is 2.4%, compared with 2.9% in the High Economic Growth case and 1.8% in the Low Economic Growth case.

In the High Economic Growth case, with greater productivity gains and a larger labor force, the U.S. economy expands by 4.1% in 2015, 3.6% in 2016, 3.2% from 2015 to 2025, and 2.9% from 2015 to 2040. In the Low Economic Growth case, the current economic recovery (which is now more than five years old) stalls in the near term, and productivity and labor force growth are weak in the long term. As a result, economic growth averages 2.4% in 2015, 1.6% in 2016, 1.7% from 2015 to 2025, and 1.8% from 2015 to 2040 in the Low Economic Growth case (Table 3).

Energy prices

Crude oil

AEO2015 considers a number of factors related to the uncertainty of future world crude oil prices, including changes in worldwide demand for petroleum products, crude oil production, and supplies of other liquid fuels.[15] In the Reference, High Oil Price, and Low Oil Price cases, the North Sea Brent (Brent) crude oil price reflects the market price for light sweet crude oil free on board (FOB) at the Sullen Voe oil terminal in Scotland.

The Reference case reflects global oil market events through the end of 2014. Over the past two years, growth in U.S. crude oil production, along with the late-2014 drop in global crude oil prices, has altered the economics of the oil market. These new market conditions are assumed to continue in the Reference case, with the average Brent price dropping from $109/barrel (bbl) in 2013 to $56/bbl in 2015, before increasing to $76/bbl in 2018. After 2018, growth in demand from non-OECD countries—countries outside the Organization for Economic Cooperation and Development (OECD)—pushes the Brent price to $141/bbl in 2040 (in 2013 dollars). The increase in oil prices supports growth in domestic crude oil production.

The High Oil Price case assumes higher world demand for petroleum products, less upstream investment by the Organization of the Petroleum Exporting Countries (OPEC), and higher non-OPEC exploration and development costs. These factors all contribute to a rise in the average spot market price for Brent crude oil to $252/bbl in 2040, 78% above the Reference case. The reverse is true in the Low Oil Price case: lower non-OECD demand, higher OPEC upstream investment, and lower non-OPEC exploration

Table 3. Average annual growth of labor productivity, employment, income, and consumption in three cases (percent per year)

	2015	2016	2015-25	2015-40
Productivity				
High Economic Growth	2.3	2.3	2.4	2.3
Reference	1.9	1.6	2.1	2.0
Low Economic Growth	1.3	0.9	1.7	1.6
Non-farm employment				
High Economic Growth	2.9	1.9	1.2	0.9
Reference	2.2	1.6	0.8	0.7
Low Economic Growth	1.6	1.1	0.6	0.5
Real personal income				
High Economic Growth	3.6	3.3	3.4	2.8
Reference	3.3	2.8	2.8	2.5
Low Economic Growth	2.7	2.4	2.4	2.3
Real personal consumption				
High Economic Growth	3.6	3.5	3.2	2.9
Reference	3.0	3.0	2.5	2.4
Low Economic Growth	2.5	2.6	1.7	1.7

Source: AEO2015 Reference case D021915a, based on IHS Global Insight T301114.wf1.

[15]Liquid fuels, or petroleum and other liquids, includes crude oil and products of petroleum refining, natural gas liquids, biofuels, and liquids derived from other hydrocarbon sources (including coal-to-liquids and gas-to-liquids).

and development costs cause the Brent spot price to increase slowly to $76/bbl, or 47% below the price in the Reference case, in 2040 (Figure 3).

World liquid fuels consumption varies in the three cases as a result of different assumptions about future trends in oil prices, world oil supply, and the rate of non-OECD demand growth. Uncertainty about world crude oil production is also captured in the three cases. In the Reference case, world production is 99.1 million bbl/d in 2040. In comparison to the Reference case, total liquid fuel supplies and OPEC's market share are higher in the Low Oil Price case and lower in the High Oil Price case. For OPEC countries in the Middle East, Africa, and South America, combined production grows from less than 32.6 million bbl/d in 2013 to 58.3 million bbl/d in 2040 in the Low Oil Price case, compared with 43.5 million bbl/d in 2040 in the Reference case and 35.0 million bbl/d in 2040 in the High Oil Price case.

As increased OPEC production depresses world oil prices in the Low Oil Price case, development of some non-OPEC resources that are viable in the Reference case become uneconomical. As a result, non-OPEC production increases only slightly in the Low Oil Price case, from 45.3 million bbl/d in 2013 to 46.8 million bbl/d in 2040. In the High Oil Price case, non-OPEC production totals 63.8 million bbl/d in 2040. Unlike the High Oil and Gas Resource case, which assumes higher estimated ultimate recovery of crude oil and natural gas per well, closer well spacing, and greater advancement in production technology than the Reference case, the High Oil Price and Low Oil Price cases assume no changes in those factors from the Reference case.

Petroleum and other liquids products

The prices charged for petroleum products and other liquid products in the United States reflect the price that refiners pay for crude oil inputs, as well as operation, transportation, and distribution costs, and the margins that refiners receive. Changes in gasoline and distillate fuel oil prices generally move in the same direction as changes in the world crude oil price, but the changes in price are also influenced by demand factors. A 30% rise in the North Sea Brent crude oil spot price from 2013 to 2040 in the Reference case results in the weighted average U.S. petroleum product price rising by 15%, from $3.16/gallon to $3.62/gallon (in 2013 dollars). However, the effect of rising crude oil prices on distillate fuel use in the United States is less than for motor gasoline, because of a greater increase in distillate fuel demand as freight requirements continue to grow and the mix of light-duty vehicle fuels shifts from gasoline to diesel fuel. U.S. distillate fuel prices rise by 23% through 2040 in the Reference case, compared to an 11% increase for motor gasoline (Figure 4 and Figure 5). However, distillate fuel consumption rises by 15%, compared to a 20% decrease in motor gasoline consumption.

In the High Oil Price case, higher demand for crude oil in non-OECD countries and lower supply of OPEC crude oil push world crude oil prices up. As a result, the weighted average

Figure 3. North Sea Brent crude oil prices in three cases, 2005-40 (2013 dollars per barrel)

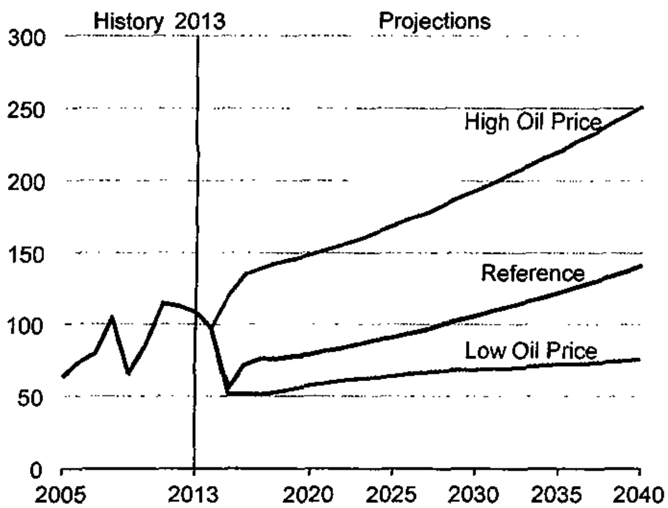


Figure 4. Motor gasoline prices in three cases, 2005-40 (2013 dollars per gallon)

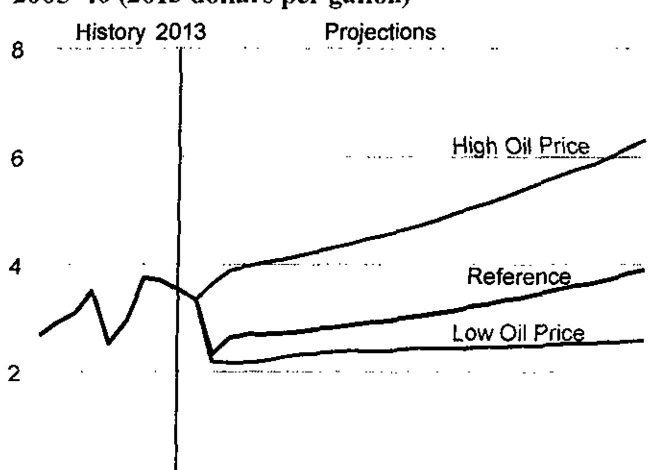
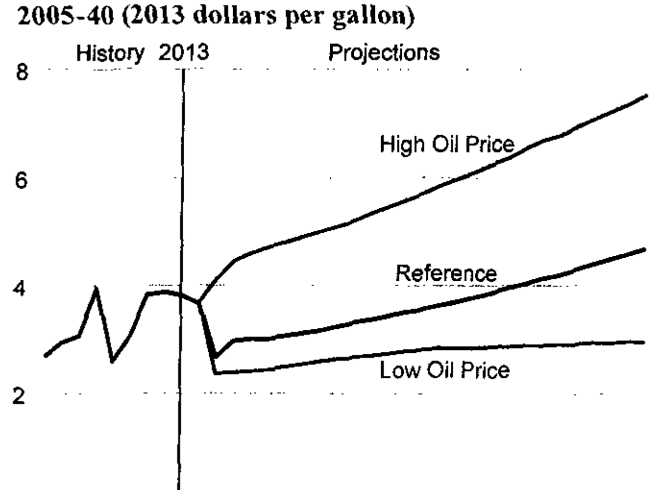


Figure 5. Distillate fuel oil prices in three cases, 2005-40 (2013 dollars per gallon)



price for U.S. petroleum products increases by 84%, from \$3.16/gallon in 2013 to \$5.81/gallon in 2040. In the Low Oil Price case, with lower non-OECD demand and higher OPEC supply pushing world oil prices down, the weighted average price for U.S. petroleum products drops by 26%, from \$3.16/gallon in 2013 to \$2.32/gallon in 2040.

In all the AEO2015 cases, U.S. laws and regulations shape demand and, consequently, the price of petroleum products in the United States. The Corporate Average Fuel Economy (CAFE) standards for new light-duty vehicles (LDVs), which typically use gasoline, rise from 30 miles per gallon (mpg) in 2013 to 54 mpg in 2040 under the fleet composition assumptions used in the final rule issued by the U.S. Environmental Protection Agency (EPA) and National Highway Transportation Safety Administration.[16] The rise in vehicle miles traveled (VMT) for LDVs does not fully offset the increase in fuel efficiency, and motor gasoline consumption declines through 2040 in all the AEO2015 cases. However, the effect of the standards varies by case because of the use of different assumptions about prices and economic growth. The 32% decrease in motor gasoline consumption in the High Oil Price case is larger than the decrease in the Reference case because higher gasoline prices reduce VMT, reducing consumption. In the Low Oil Price case, the decrease in gasoline consumption (11%) is smaller than in the Reference case because lower gasoline prices stimulate enough increased VMT to offset a part of the impact of fuel efficiency improvements resulting from regulation.

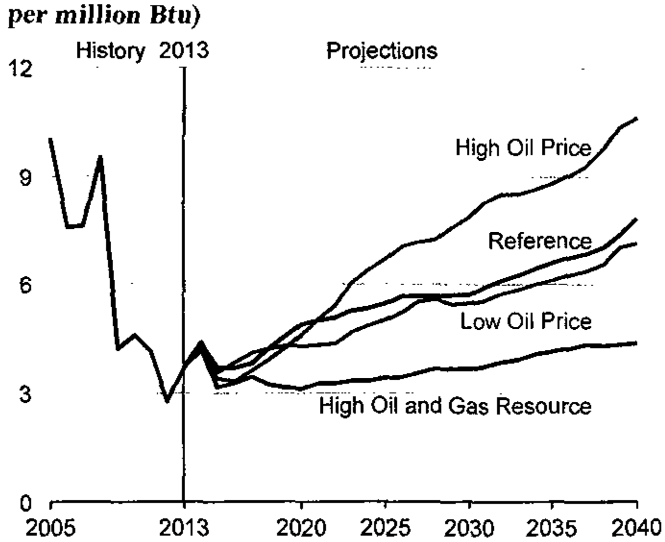
The efficiency and greenhouse gas (GHG) standard for heavy-duty vehicles, which typically consume distillate fuel, rises by about 16% through 2040, remaining below 8 mpg in all AEO2015 cases. Unlike the case for LDVs, the higher VMT in the Low Oil Price case more than offsets the increase in vehicle fuel efficiency, and distillate fuel consumption increases by 21% from 2013 to 2040. The increase in fuel consumption in the Low Oil Price case is greater than in the Reference case as a result of a 22% decrease in distillate fuel prices, to \$2.97/gallon in 2040. In the High Oil Price case, the price of distillate fuel oil increases to \$7.55/gallon in 2040—61% higher than in the Reference case—resulting in a 2% decline in distillate fuel consumption.

Natural gas

Henry Hub natural gas spot prices vary according to assumptions about the availability of domestically produced natural gas resources, overseas demand for U.S. liquefied natural gas (LNG), and trends in domestic consumption. In all cases, prices are lower in 2015 than the \$3.73/million British thermal units (Btu) average Henry Hub spot price in 2013, and in most cases they are above that level by 2020 (Figure 6). In the AEO2015 Reference case, the Henry Hub spot price is \$4.88/million Btu (2013 dollars) in 2020 and \$7.85/million Btu in 2040, as increased demand in domestic and international markets requires an increased number of well completions to achieve higher levels of production. In addition, lower cost resources generally are expected to be produced earlier, with more expensive production occurring later in the projection period.

In the High Oil and Gas Resource case, U.S. domestic production from tight oil and natural gas formations is higher than in the Reference case as a result of assumed greater estimated ultimate recovery (EUR) per well, closer well spacing, and greater gains in technological development. Consequently, even with low natural gas prices, total U.S. domestic dry natural gas production grows sufficiently to satisfy higher levels of domestic consumption, as well as higher pipeline and LNG exports. With the abundance of natural gas produced domestically, the Henry Hub spot price (in 2013 dollars) falls from \$3.14/million Btu in 2015 to \$3.12/million Btu in 2020 (36% below the Reference case price) before rising to \$4.38/million Btu in 2040 (44% below the Reference case price).

Figure 6. Average Henry Hub spot prices for natural gas in four cases, 2005-40 (2013 dollars per million Btu)



The Low and High Oil Price cases assume the same level of resource availability as the Reference case but different world oil prices, which affect the level of overseas demand for U.S. LNG exports. International LNG contracts are often linked to crude oil prices, even though their relationship may be weakening. Global demand for LNG is also directly influenced by oil prices, as LNG competes directly with petroleum products in many applications. When the North Sea Brent spot price, which is the principal benchmark price for crude oil on world markets, rises in the High Oil Price case, world LNG contracts linked to oil prices become more expensive, making LNG exports from the United States more desirable.

In the High Oil Price case, the Henry Hub natural gas spot price remains close to the Reference case price through 2020. However, higher overseas demand for U.S. LNG exports raises the average Henry Hub spot price to \$10.63/million Btu in 2040, which is 35% above the Reference case price.

[16] U.S. Environmental Protection Agency and National Highway Transportation Safety Administration, "2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy Standards; Final Rule," *Federal Register*, Vol. 77, No. 199 (Washington, DC, October 15, 2012), https://www.federalregister.gov/articles/2012/10/15/2012-21972/2017-and-later-model-year-light-duty-vehicle-greenhouse-gas-emissions-and-corporate-average-fuel.

In the Low Oil Price case, with lower demand for U.S. LNG exports, the Henry Hub spot price is only $7.15/million Btu in 2040—which is 9% lower than in the Reference case but 63% higher than in the High Oil and Gas Resource case.

Changes in the Henry Hub natural gas spot price generally translate to changes in the price of natural gas delivered to end users. The delivered price of natural gas to the electric power sector is highest in the High Oil Price case, where it rises from $4.40/million Btu in 2013 to $10.08/million Btu in 2040, compared with $8.28/million Btu in the Reference case. Higher delivered natural gas prices result in a decline in natural gas consumption in the electric power sector in the High Oil Price case, from 8.2 Tcf in 2013 to 6.8 Tcf in 2040, compared with an increase in natural gas consumption in the electric power sector to 9.4 Tcf in 2040 in the Reference case. In the Low Oil Price and High Oil and Gas Resource cases, smaller increases in delivered natural gas prices result in more consumption for power generation than in the Reference case or High Oil Price case in 2040.

As in the electric power sector, natural gas consumption in the U.S. industrial sector also changes in response to delivered natural gas prices. However, industrial natural gas consumption also changes in response to shifts in the mix of industrial output, as well as changes in refinery output and utilization. Consumption also varies with the relative economics of using natural gas for electricity generation in industrial combined heat and power (CHP) facilities. The largest increase in the price of natural gas delivered to the industrial sector, from $4.56/million Btu in 2013 to $11.03/million Btu in 2040, is seen in the High Oil Price case, followed by the Reference case ($8.78/million Btu in 2040), Low Oil Price case ($8.25/million Btu in 2040), and High Oil and Gas Resource case ($5.22/million Btu in 2040). Of those four cases, the largest increase in industrial natural gas consumption occurs in the High Oil and Gas Resource case, in which lower prices contribute to higher consumption. The next largest increase occurs in the High Oil Price case, where higher prices spur a significant increase in U.S. crude oil production and, accordingly, natural gas consumption at U.S. oil refineries.[17]

The price of natural gas delivered to the residential and commercial sectors increases from 2013 to 2040 in all the AEO2015 cases. The largest increase in delivered natural gas prices to both sectors through 2040 is in the High Oil Price case, followed by the Reference, Low Oil Price, and High Oil and Gas Resource cases. In the commercial sector, natural gas consumption increases in all cases, mainly as a result of increased commercial CHP use and growth in aggregate commercial square footage. Conversely, consumption in the residential sector decreases in all cases despite economic growth, as overall demand is reduced by population shifts to warmer areas, improvements in appliance efficiency, and increased use of electricity for home heating.

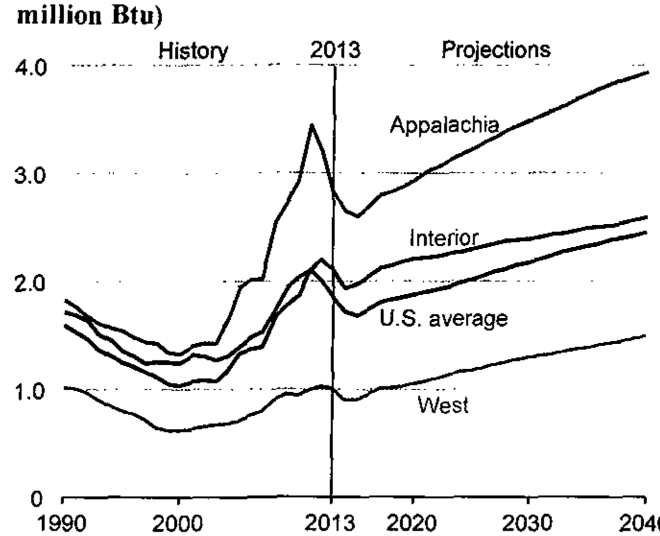
Coal

The average minemouth coal price increases by 1.0%/year in the AEO2015 Reference case, from $1.84/million Btu in 2013 to $2.44/million Btu in 2040. Higher prices result primarily from declines in coal mining productivity in several key supply regions, including Central Appalachia and Wyoming's Powder River Basin.

Across the AEO2015 alternative cases, the most significant changes in the average minemouth coal price compared with the Reference case occur in the Low and High Oil Price cases. In 2040, the average minemouth price is 6% lower in the Low Oil Price case and 7% higher in the High Oil Price case than in the Reference case. These variations from the Reference case are primarily the result of differences in the projections for diesel fuel and electricity prices in the Low and High Oil Price cases, because diesel fuel and electricity are key inputs to the coal mining process. The AEO2015 cases do not include the EPA's proposed Clean Power Plan,[18] which if implemented would likely have a substantial impact on coal use for power generation and coal markets more generally.

Increases in minemouth coal prices (in dollars/million Btu) occur in all coal-producing regions (Figure 7). In Appalachia and in the West, increases of 1.2%/year and 1.5%/year between 2013 and 2040, respectively, are primarily the result of continuing declines in coal mining productivity. In the Interior region, a more optimistic outlook for coal mining productivity, combined with substantially higher production quantities, results in slower average price growth of 0.8%/year from 2013 to 2040. Increased output from large, highly productive longwall mines in the Interior region support labor productivity gains averaging 0.3%/year over the same period.

Figure 7. Average minemouth coal prices by region in the Reference case, 1990-2040 (2013 dollars per million Btu)



[17]While not discussed in this section, the High Economic Growth case has higher levels of industrial natural gas consumption through 2040 than any of the four cases mentioned, in response to higher demand that results from significantly higher levels of industrial output.

[18]U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," *Federal Register*, pp. 34829-34958 (Washington, DC: June 18, 2014) https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.

The average delivered price of coal (the sum of minemouth and coal transportation costs) increases at a similar, but slightly slower pace of 0.8%/year than minemouth prices, with prices rising from $2.50/million Btu in 2013 to $3.09/million Btu in 2040 in the AEO2015 Reference case (Figure 8). A relatively flat outlook for coal transportation rates results in a slightly lower growth rate for the average delivered price of coal.

Electricity

The average retail price of electricity in real 2013 dollars increases in the AEO2015 Reference case by 18% from 2013 to 2040 as a result of rising costs for power generation and delivery, coupled with relatively slow growth in electricity demand (0.7%/year on average). Electricity prices are determined by a complex set of factors that include economic conditions; energy use and efficiency; the competitiveness of electricity supply; investment in new generation, transmission, and distribution capacity; and the fuel, operation, and maintenance costs of plants in service. Figure 9 illustrates effects on retail electricity prices in the AEO2015 Reference and alternative cases resulting from different assumptions about the factors determining prices.

In the AEO2015 Reference case, average retail electricity prices (2013 dollars) increase by an average of 0.6%/year, from 10.1 cents/kilowatthour (kWh) in 2013 to 11.8 cents/kWh in 2040, an overall increase of 18%. The High Oil Price case shows the largest overall average price increase, at 28%, to 12.9 cents/kWh in 2040. The High Oil and Gas Resource case shows the smallest average increase, at 2%, to 10.3 cents/kWh in 2040. With more fuel resources available to meet demand from power producers in the High Oil and Gas Resource case, lower fuel prices lead to lower generation costs and lower retail electricity prices for consumers. In the High Economic Growth case, stronger economic growth increases demand for electricity, putting price pressure on the fuel costs and the construction cost of new generating plants. In the Low Economic Growth case, weaker growth results in lower electricity demand and associated costs.

The average annual growth in electricity use (including sales and direct use) in the United States has slowed from 9.8%/year in the 1950s to 0.5%/year over the past decade. Contributing factors include slowing population growth, market saturation of major electricity-using appliances, efficiency improvements in appliances, and a shift in the economy toward a larger share of consumption in less energy-intensive industries. In the AEO2015 Reference case, U.S. electricity use grows by 0.8%/year on average from 2013 to 2040.

Combined electricity demand in the residential and commercial sectors made up over 70% of total electricity demand in 2013, with each sector using roughly the same amount of electricity. From 2013 to 2040, residential and commercial electricity prices increase by 19% and 16%, respectively, in the Reference case; by 30% and 27% in the High Oil Price case; and by 5% and 0% in the High Oil and Gas Resource case. These variations largely reflect the importance of natural gas prices to electricity prices.

Industrial electricity prices grow by 22% in the Reference case, from 6.9 cents/kWh in 2013 to 8.4 cents/kWh in 2040. Among the alternative cases, growth in industrial electricity prices ranges from 35% (9.3 cents/kWh in 2040) in the High Oil Price case to 2% (7.1 cents/KWh in 2040) in the High Oil and Gas Resource case. In the industrial sector, electricity use increases in most industries but falls throughout the projection period for the energy-intensive refining and paper industries and, after 2024, in the aluminum, bulk chemical, and mining industries.

Retail electricity prices include generation, transmission, and distribution components. In the AEO2015 cases, about two-thirds of the retail price of electricity (between 59% and 67%) is attributable to the price of generation, which includes generation costs and retail taxes, with the remaining portion attributable to transmission and distribution costs. The generation price increases by 0.5% annually in the Reference case, from 6.6 cents/kWh in 2013 to 7.6 cents/kWh in 2040. In the High Oil Price Case, the price

Figure 8. Average delivered coal prices in six cases, 1990-2040 (2013 dollars per million Btu)

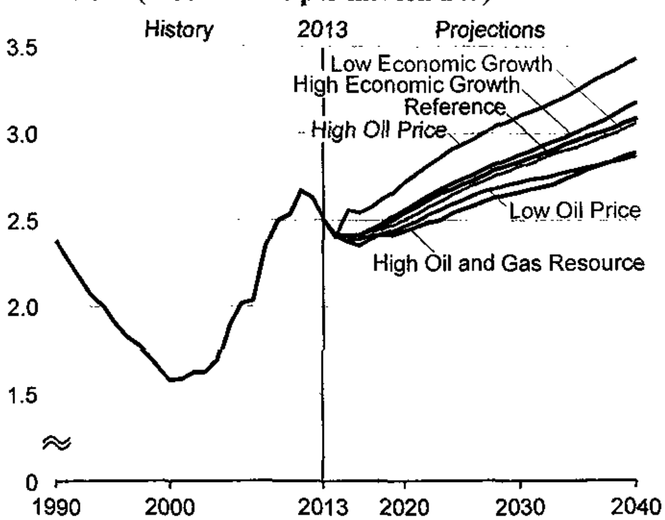
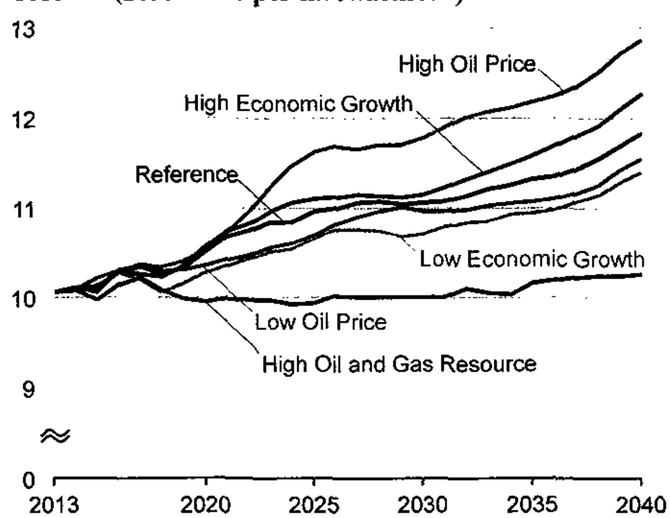


Figure 9. Average retail electricity prices in six cases, 2013-40 (2013 cents per kilowatthour)



of generation increases by 1%/year to 8.6 cents/kWh in 2040; and in the High Oil and Gas Resource Case, it falls by 0.3%/year to 6.1 cents/kWh in 2040.

Generation prices are determined differently in states with regulated and competitive electricity supplies. The AEO2015 Reference case assumes that 67% of electricity sales are subject to regulated average-cost pricing and 33% are priced competitively, based on the marginal cost of energy. In fully regulated regions, the price of generation is determined by both fixed costs (such as the costs of paying off electricity plant construction and fixed operation and maintenance costs) and variable costs (fuel and variable operation and maintenance costs).

In the Reference case, new generation capacity added through the projection period includes 144 GW of natural gas capacity, 77 GW of renewable capacity (45% is wind and 44% solar), 9 GW of nuclear capacity, and 1 GW of coal-fired capacity. Significant variation in the mix of generation capacity types added in the different AEO2015 cases also affects generation prices. Natural gas capacity additions vary substantially, with only 117 GW added in the Low Economic Growth case and 236 GW added in the High Economic Growth case. In the High Economic Growth case, a more vibrant economy leads to more industrial and commercial activity, more consumer demand for electric devices and appliances, and consequently greater demand for electricity.

Renewable generation capacity additions vary the most, with 66 GW added in the High Oil and Gas Resource case, but 194 GW added in the High Economic Growth case. Only 6 GW of new nuclear capacity is built in the Low Economic Growth and High Oil and Gas Resource cases, but 22 GW of new nuclear capacity is added in the High Oil Price case where natural gas prices are significantly above those in the Reference case. Across all the AEO2015 cases, very little new coal-fired capacity—and no new oil-fired capacity—is built through 2040.

Most generating fuel costs are attributed to coal and natural gas. In 2013, coal made up 44% of total generation fuel costs, and natural gas made up 42%. In 2040, coal makes up only 35% of total fuel costs in the Reference case, compared with 55% for natural gas. Oil, which is the most expensive fuel for generation, accounted for 6% of the total generating fuel costs in 2013 and from 2019 through 2040 accounts for only 3% of the total. Nuclear fuel accounts for 6% to 8% of electricity generation fuel costs throughout the projection period.

In regions with competitive wholesale electricity markets, the generation price generally follows the natural gas price. The price of electricity in wholesale markets is determined by the marginal cost of energy—the cost of serving the next increment of demand for a determined time period. Natural gas fuels the marginal generators during most peak and some off-peak periods in many regions.

There has been a fivefold increase in investment in new electricity transmission capacity since 1997, as well as large increases in spending for distribution capacity. Since 1997, roughly $107 billion has been spent on new transmission infrastructure and $318 billion on new distribution infrastructure, both in 2013 dollars. Those investments are paid off gradually over the projection period.

Although investment in new transmission and distribution capacity does not continue in the AEO2015 Reference case at the pace seen in recent years, spending still occurs at a rate greater than that needed to keep up with demand driven by requirements for additional transmission and distribution capacity to interconnect with new renewable energy sources, grid reliability and resiliency improvements, community aesthetics (including burying lines), and smart grid construction. In the AEO2015 Reference case, the transmission portion of the price of electricity increases by 1.2%/year, from 0.9 cents/kWh in 2013 to 1.3 cents/kWh in 2040. The distribution portion of the electricity price increases by 0.6%/year over the projection period, from 2.6 cents/kWh in 2013 to 3.0 cents/kWh in 2040. The investments in distribution capacity are undertaken mainly to serve residential and commercial customers. As a result, residential and commercial customers typically pay significantly higher distribution charges per kilowatthour than those paid by industrial customers.

Delivered energy consumption by sector

Transportation

Energy consumption in the transportation sector declines in the AEO2015 Reference case from 27.0 quadrillion Btu (13.8 million bbl/d) in 2013 to 26.4 quadrillion Btu (13.5 million bbl/d) in 2040. Energy consumption falls most rapidly through 2030, primarily as a result of improvement in light-duty vehicle (LDV) fuel economy with the implementation of corporate average fuel economy (CAFE) standards and greenhouse gas emissions (GHG) standards (Figure 10). This projection is a significant departure from the historical trend. Transportation energy consumption grew by an average of 1.3%/year from 1973 to 2007—when it peaked at 28.7 quadrillion Btu—as a result of increases in demand for personal travel and movement of goods that outstripped gains in fuel efficiency.

Transportation sector energy consumption varies across the alternative cases (Figure 11). Compared with the Reference case, energy consumption levels in 2040 are higher in the High Economic Growth case (by 3.0 quadrillion Btu), Low Oil Price case (by 1.4 quadrillion Btu), and High Oil and Gas Resource case (by 1.2 quadrillion Btu) and lower in the High Oil Price case (by 1.4 quadrillion Btu) and Low Economic Growth case (by 2.6 quadrillion Btu).

In the Reference case, energy consumption by LDVs—including passenger cars, light-duty trucks, and commercial light-duty trucks—falls from 15.7 quadrillion Btu in 2013 to 12.6 quadrillion Btu in 2040, as increases in fuel economy more than offset increases in LDV travel. Total vehicle miles traveled (VMT) for LDVs increase by 36% from 2013 (2,711 billion miles) to 2040 (3,675 billion miles), and the average VMT per licensed driver increase from about 12,200 miles in 2013 to 13,300 miles in 2040. The fuel economy of new vehicles increases from 32.8 mpg in 2013 to 48.1 mpg in 2040, as more stringent CAFE and GHG emissions standards take effect. As a result, the average fuel economy of the LDV stock increases by 69%, from 21.9 mpg in 2013 to 37.0 mpg in 2040.

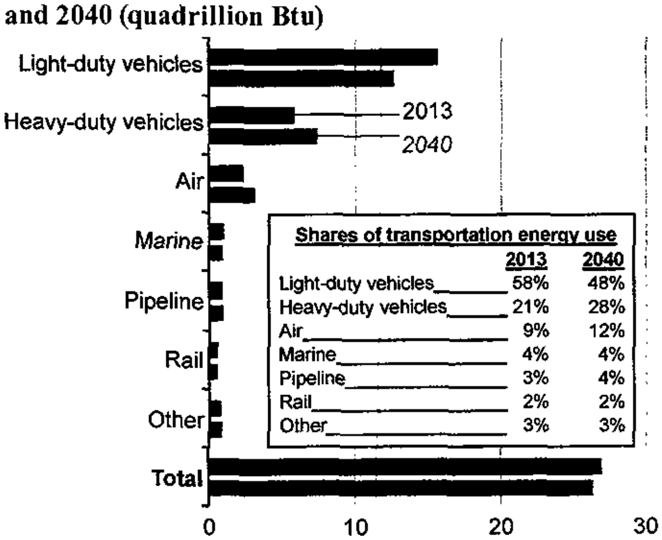
Passenger vehicles fueled exclusively by motor gasoline for all motive and accessory power, excluding any hybridization and flex-fuel capabilities, accounted for 83% of new sales in 2013. In the AEO2015 Reference case, gasoline-only vehicles, excluding hybridization or flex-fuel capabilities, still represent the largest share of new sales in 2040, at 46% of the total (see the first box below for comparison of relative economics of various technologies). However, alternative fuel vehicles and vehicles with hybrid technologies gain significant market shares, including gasoline vehicles equipped with micro hybrid systems (33%), E85 flex-fuel vehicles (10%), full hybrid electric vehicles (5%), diesel vehicles (4%), and plug-in hybrid vehicles and electric vehicles (2%). (EIA considers several types of hybrid electric vehicles—micro, mild, full, and plug-in—as described in the box on page 11.)

In comparison with the Reference case, LDV energy consumption in 2040 is higher in the Low Oil Price case (14.3 quadrillion Btu), High Economic Growth case (13.2 quadrillion Btu), and High Oil and Gas Resource case (12.9 quadrillion Btu), as a result of projected higher VMT in all three cases and lower fuel economy in the Low Oil Price and High Oil and Gas Resource cases. Conversely, LDV energy consumption in 2040 in the High Oil Price case (10.6 quadrillion Btu) and the Low Economic Growth case (11.3 quadrillion Btu) is lower than projected in the Reference case, as a result of lower VMT in both cases and higher fuel economy in the High Oil Price case.

Energy use by all heavy-duty vehicles (HDVs)—including tractor trailers, buses, vocational vehicles,[19] and heavy-duty pickups and vans—increases from 5.8 quadrillion Btu (2.8 million bbl/d) in 2013 to 7.3 quadrillion Btu (3.5 million bbl/d) in 2040, with higher VMT only partially offset by improved fuel economy. HDV travel grows by 48% in the Reference case—as a result of increases in industrial output—from 268 billion miles in 2013 to 397 billion miles in 2040, while average HDV fuel economy increases from 6.7 mpg in 2013 to 7.8 mpg in 2040 as a result of HDV fuel efficiency standards and GHG emissions standards. Diesel remains the most widely used HDV fuel. The share of diesel falls from 92% of total HDV energy use in 2013—with the remainder 7% motor gasoline and 1% gaseous (propane, natural gas, liquefied natural gas)—to 87% diesel in 2040, with natural gas, either compressed or liquefied, accounting for 7% of HDV energy use in 2040 as the economics of natural gas fuels improve and the refueling infrastructure expands.

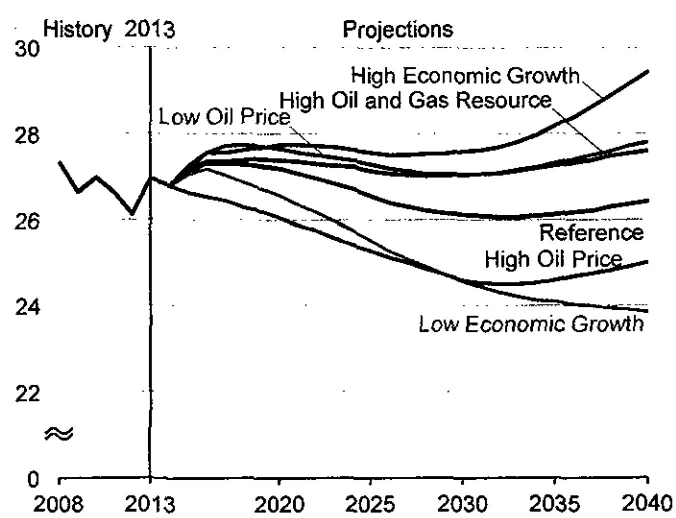
The largest differences from the Reference case level of HDV energy consumption in 2040 are in the High and Low Economic Growth cases (9.4 quadrillion Btu and 6.3 quadrillion Btu, respectively), as a result of their higher and lower projections for travel demand, respectively. Notably, the use of natural gas is significantly higher in the High Oil Price case than in the Reference case, at nearly 30% of total HDV energy use in 2040.

Figure 10. Delivered energy consumption for transportation by mode in the Reference case, 2013 and 2040 (quadrillion Btu)



Note: The sum of the shares may not equal 100% due to independent rounding.

Figure 11. Delivered energy consumption for transportation in six cases, 2008-40 (quadrillion Btu)

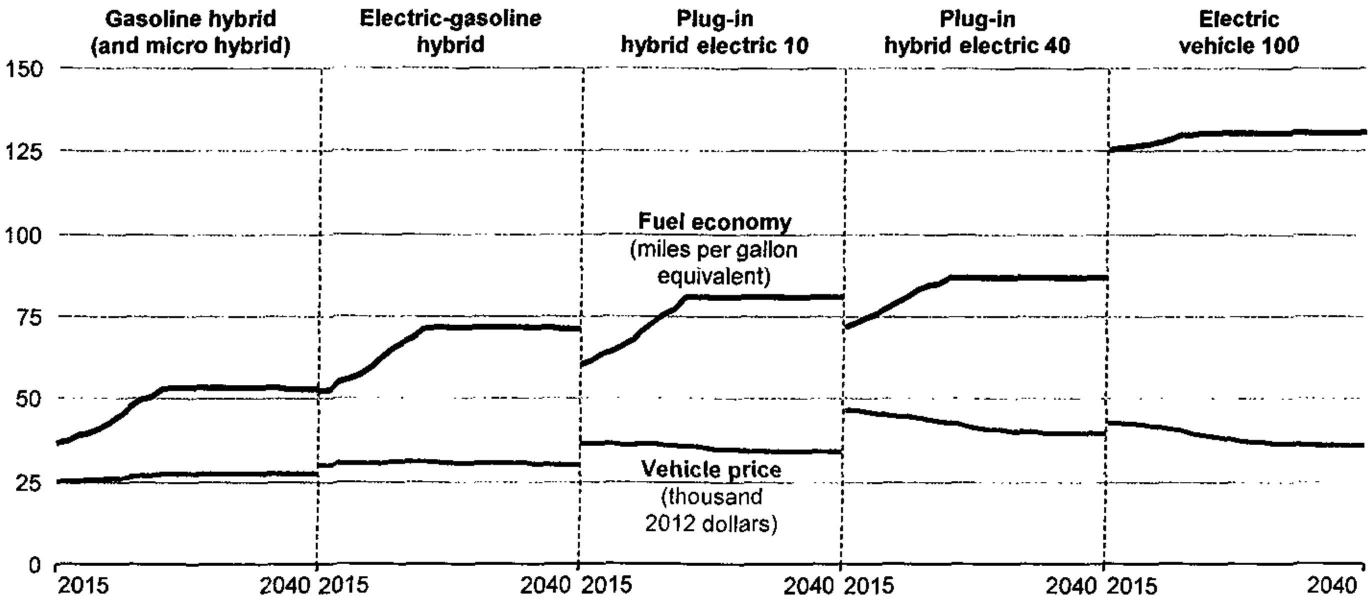


[19]Vocational vehicles include a diverse group of heavy-duty trucks, such as box/delivery trucks, refuse haulers, dump trucks, etc.

Future gasoline vehicles are strong competitors when compared with other vehicle technology types on the basis of fuel economics

Several fuel-efficient technologies are currently, or are expected to be, available for all vehicle fuel types. Those technologies will enable manufacturers to meet upcoming CAFE and GHG emissions standards at a relatively modest cost, predominately with vehicles powered by gasoline only or with gasoline-powered vehicles employing micro hybrid systems. Because of diminishing returns from improved fuel economy, future gasoline vehicles, including those with micro hybrid systems, are strong competitors when compared with other, more expensive vehicle technology types on the basis of fuel economics. Even though the price of vehicles that use some electric drive for motive power is projected to decline, in some cases significantly, their relative cost-effectiveness does not improve over the projection period, due to advances in gasoline-only and gasoline micro hybrid vehicles. While the reasons for consumer vehicle purchases vary and are not always on a strictly economic basis, wider market acceptance would require more favorable fuel economics—as seen in the High Oil Price case, where sales of plug-in hybrid and electric vehicle sales more than double.

Midsize passenger car fuel economy and vehicle price by technology type in the Reference case, 2015-2040



In 2040, compared with gasoline vehicles, fuel cost savings would be $227/year for an electric-gasoline hybrid, with a "payback period" of approximately 13 years for recovery of the difference in vehicle purchase price compared with a conventional gasoline vehicle; $247/year for a PHEV10, with a 27-year payback period; $271/year for a PHEV40, with a 46-year payback period; and $469/year for a 100% electric drive vehicle, with a 19-year payback period. These results are based on the following assumptions for each vehicle type: 12,000 miles traveled per year; average motor gasoline price of $3.90 per gallon; average electricity price of $0.12 per kilowatthour; and 0% discount rate. For plug-in hybrids it is assumed that a hybrid electric 10 (PHEV10) will use electric drive power for 21% of total miles traveled, and a hybrid electric 40 (PHEV40) for 58% of total miles traveled. The assumed vehicle purchase prices do not reflect national or local tax incentives.

The *Annual Energy Outlook 2015* includes several types of light-duty vehicle hybrid technology

Micro hybrids, also known as start/stop technology, are those vehicles with an electrically powered auxiliary system that allow the internal combustion engine to be turned off when the vehicle is coasting or idle and then quickly restarted. These systems do not provide power to the wheels for traction and can use regenerative braking to recharge the batteries.

Mild hybrids are those vehicles that, in addition to start/stop capability, provide some power assist to the wheels but no electric-only motive power.

Full hybrid electric vehicles can, in addition to start/stop and mild capabilities, operate at slow speeds for limited distances on the electric motor and assists the drivetrain throughout its drive cycle. Full hybrid electric vehicle systems are configured in parallel, series, or power split systems, depending on how power is delivered to the drivetrain.

Plug-in hybrid electric vehicles have larger batteries to provide power to drive the vehicle for some distance in charge-depleting mode, until a minimum level of battery power is reached (a "minimum state of charge"), at which point they operate on a mixture of battery and internal combustion engine power ("charge-sustaining mode"). PHEVs also can be engineered to run in a "blended mode," using an onboard computer to determine the most efficient use of battery and engine power. The battery can be recharged either from the grid (plugging a power cord into an electrical outlet) or by the engine.

Aircraft energy consumption increases from 2.3 quadrillion Btu in 2013 to 3.1 quadrillion Btu in 2040, with growth in personal air travel partially offset by gains in aircraft fuel efficiency. Energy consumption by marine vessels (including international marine, recreational boating, and domestic marine) remains flat, as increases in demand for international marine and recreational boating are offset by declines in fuel use for domestic marine vessels. The decline in domestic marine energy use is the result of improved efficiency and the continuation of the historical decline in travel demand. In the near term, distillate fuel provides a larger share of the fuel used by marine vessels, the result of stricter fuel and emissions standards. Pipeline energy use increases slowly, with growing volumes of natural gas produced from tight formations that are relatively close to end-use markets. Energy consumption for rail travel (freight and passenger) also remains flat, as improvement in locomotive fuel efficiency offsets growth in travel demand. In 2040, natural gas provides about a third of the fuel used for freight rail.

Industrial

Delivered energy consumption in the industrial sector totaled 24.5 quadrillion Btu in 2013, representing approximately 34% of total U.S. delivered energy consumption. In the AEO2015 Reference case, industrial delivered energy consumption grows at an annual rate of 0.7% from 2013 to 2040. The annual growth rate is much higher from 2013 to 2025 (1.3%) than from 2025 to 2040 (0.2%), as increased international competition slows industrial production growth and energy efficiency continues to improve in the industrial sector over the long term. Among the alternative cases, delivered industrial energy consumption grows most rapidly in the High Economic Growth case at 1.2%/year, almost twice the rate in the Reference case. The slowest growth in industrial energy consumption is projected in the Low Economic Growth case, at 0.4%/year from 2013 to 2040 (Figure 12).

Total industrial natural gas consumption in the AEO2015 Reference case increases from 9.1 quadrillion Btu in 2013 to 11.2 quadrillion Btu in 2040. Natural gas is used in the industrial sector for heat and power, bulk chemical feedstocks, natural gas-to-liquids (GTL) heat and power, and lease and plant fuel. The 6.7 quadrillion Btu of natural gas used for heat and power in 2013 was 74% of total industrial natural gas consumption for the year. From 2013 to 2040, natural gas use for heat and power grows by an average of 0.4%/year in the Reference case, with 41% of the total growth occurring between 2013 and 2020. In the High Oil and Gas Resource case, natural gas use for heat and power grows by 0.7%/year from 2013 to 2040, largely as a result of oil and gas extraction activity (Figure 13).

Natural gas use for GTL is responsible for the rapid post-2025 consumption growth in the High Oil Price compared with the other two cases shown in Figure 13. In the High Oil Price case, natural gas use for heat and power increases by 1.0%/year from 2013 to 2040, including significant use for GTL production, which grows to about 1 quadrillion Btu in 2040 in the High Oil Price case. Natural gas use for GTL occurs only in the High Oil Price case. Market conditions (primarily liquid fuel prices) do not support GTL investments in the other cases.

Purchased electricity (excluding electricity generated and used onsite) used by industrial customers in the AEO2015 Reference case grows from 3.3 quadrillion Btu in 2013 to 4.1 quadrillion Btu in 2040. Most of the growth occurs between 2013 and 2025, when it averages 1.7%/year. After 2025, there is little growth in purchased electricity consumption in the Reference case. In the High Economic Growth case, purchased electricity consumption grows by 1.5%/year from 2013 to 2040, which is almost twice the rate in the Reference case. Consumption increases significantly from 2025 to 2040 in the High Economic Growth case, as shipments of industrial products increase relatively more than in the Reference case and do not slow down nearly as much after 2025.

Figure 12. Industrial sector total delivered energy consumption in three cases, 2010-40 (quadrillion Btu)

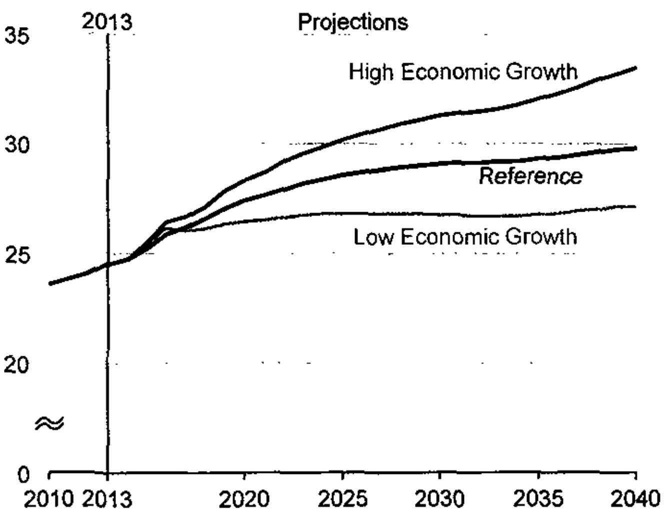
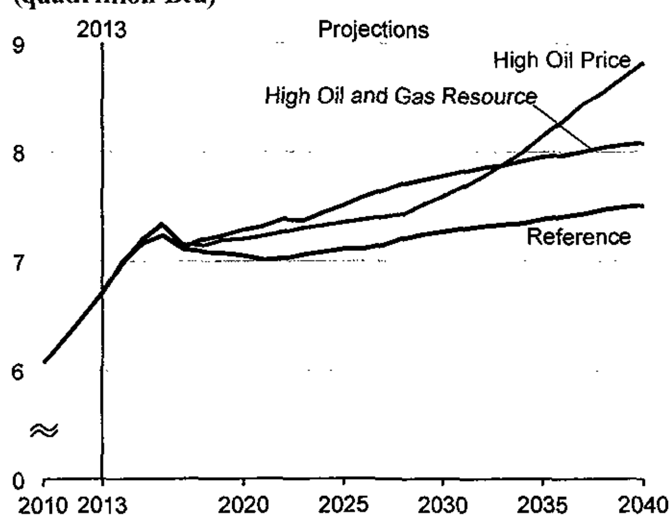


Figure 13. Industrial sector natural gas consumption for heat and power in three cases, 2010-40 (quadrillion Btu)



Purchased electricity consumption in the five metal-based durables industries,[20] which accounted for nearly 25% of the industrial sector total in 2013, grows at a slightly higher rate than in other industries in the Reference case. Although metal-based durable industries are not energy-intensive, they are relatively electricity-intensive, and they are by far the largest industry subgroup as measured by shipments in 2013. In the High Economic Growth case, shipments of metal-based durables grow more rapidly than shipments from many of the other industry segments. As a result, purchased electricity consumption in the metal-based durables industries grows by 2.0% per year from 2013 to 2040 in the High Economic Growth case, which is higher than the rate of growth for the industry in the Reference case.

Combined heat and power (CHP) generation in the industrial sector—almost all of which occurs in the bulk chemicals, food, iron and steel, paper, and refining industries—grows by 50% from 147 billion kWh in 2013 to 221 billion kWh in 2040 in the AEO2015 Reference case. Most of the CHP generation uses natural gas, although the paper industry also has a significant amount of renewables-based generation. All of the CHP-intensive industries are also energy intensive. Growth in CHP generation is slightly higher than growth in purchased electricity consumption, despite a shift toward lower energy intensity in the manufacturing and service sectors in the United States.

Bulk chemicals are the most energy-intensive segment of the industrial sector. In the AEO2015 Reference case, energy consumption in the U.S. bulk chemicals industry, which totaled 5.6 quadrillion Btu in 2013, grows by an average of 2.3%/year from 2013 to 2025. After 2025, energy consumption growth in bulk chemicals is negligible, as U.S. shipments of bulk chemicals begin to decrease because of increased international competition.

Approximately 60% of energy use in the bulk chemicals industry over the projection period is for feedstocks. Hydrocarbon gas liquids (HGL)[21] and petroleum products (such as naphtha)[22] are used as feedstocks for organic chemicals, inorganic chemicals, and resins. Growth in natural gas production from shale formations has contributed to an increase in the supply of HGL. Some chemicals can use either HGL or petroleum as feedstock; for those chemicals, the feedstock used depends on the relative prices of natural gas and petroleum. Although HGL or petroleum is used as a feedstock for most chemicals, natural gas feedstocks are used to manufacture methanol and agricultural chemicals. Natural gas feedstock consumption, which constituted roughly 13% of total bulk chemical feedstock consumption in 2013, grows rapidly from 2014 to 2018, reflecting increased capacity in the U.S. agricultural chemicals industry.

Residential and commercial

Delivered energy consumption decreases at an average rate of 0.3%/year in the residential sector and grows by 0.6%/year in the commercial sector from 2013 through 2040 in the AEO2015 Reference case (Figure 14 and Figure 15). Over the same period, the total number of households grows by 0.8%/year, and commercial floorspace increases by 1.0%/year (Table 4). The AEO2015 alternative cases illustrate the effects of different assumptions on residential and commercial energy consumption. Higher or lower economic growth, fuel prices, and fuel resources yield a range of residential and commercial energy demand. Different

Figure 14. Residential sector delivered energy consumption by fuel in the Reference case, 2010-40 (quadrillion Btu)

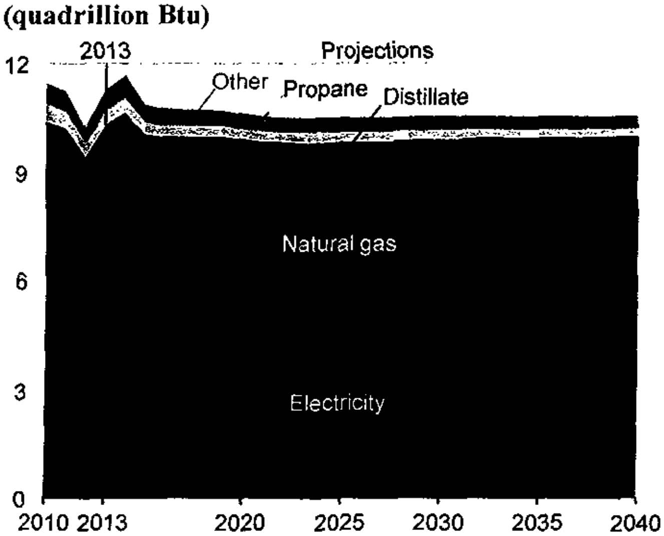
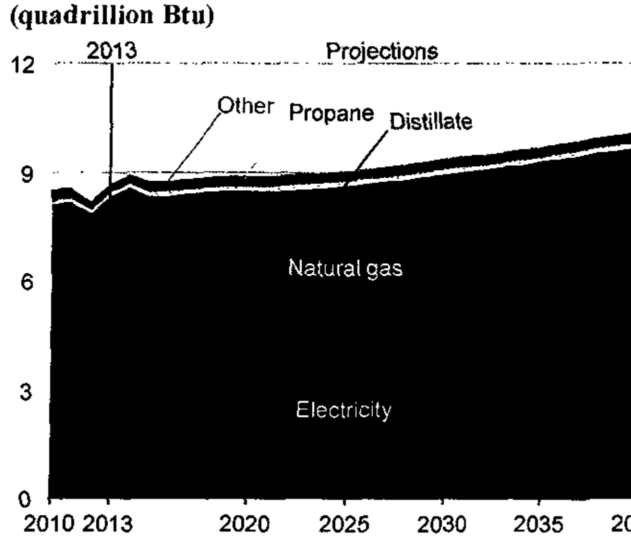


Figure 15. Commercial sector delivered energy consumption by fuel in the Reference case, 2010-40 (quadrillion Btu)



[20]The five metal-based durables industries are fabricated metal products (NAICS 332), machinery (NAICS 333), computers (NAICS 335), transportation equipment (NAICS 336), and electrical equipment (NAICS 335).

[21]Hydrocarbon gas liquids are natural gas liquids (NGL) and olefins. NGL include ethane, propane, normal butane, isobutane, and natural gasoline. Olefins include ethylene, propylene, butylene, and isobutylene. See http://www.eia.gov/tools/glossary/index.cfm?id=Hydrocarbon%20gas%20liquids.

[22]Naphtha is a refined or semi-refined petroleum fraction used in chemical feedstocks and many other petroleum products, see www.eia.gov/tools/glossary/index.cfm?id=naphtha.

levels of economic growth affect the number of households more than the amount of commercial floorspace, leading to greater differences in residential energy demand across the cases.

In the Reference case, electricity consumption in the residential and commercial sectors increases by 0.5%/year and 0.8%/year from 2013 through 2040, respectively, with the growth in residential electricity use ranging from 0.2%/year to 0.9%/year and the growth in commercial electricity use ranging from 0.7% to 0.9%/year in the alternative cases. In all cases, demand shifts from space heating to space cooling as a growing share of the population moves to warmer regions of the country. Miscellaneous electric loads (MELs)—from a variety of devices and appliances that range from microwave ovens to medical imaging equipment—continue to grow in the residential and commercial sectors, showing both increased market penetration (the share of the potential market that uses the device) and saturation (the number of devices per building).

In the commercial sector, the use of computer servers continues to grow to meet increasing needs for data storage, data processing, and other cloud-based services; however, only a small number of servers are installed in large, dedicated data center buildings. Most of the electricity used by servers can be attributed to equipment located in server rooms at the building site in offices, education buildings, and healthcare facilities.

Residential natural gas use declines in the Reference case with improvements in equipment and building shell efficiencies, price increases over time, and reduced heating needs as populations shift. Natural gas consumption in the commercial sector would be relatively flat as a result of efficiency improvements that offset floorspace growth, but increases in natural gas-fueled CHP capacity keep sector consumption trending upward throughout the projection. In the residential and commercial sectors, natural gas prices increase 2.5 and 3.0 times faster, respectively, than electricity prices through 2040 in the Reference case. In the High Oil and Gas Resources case, with lower natural gas prices, commercial delivered natural gas consumption grows by 0.7%/year, or more than twice the rate in the Reference case.

In the residential sector, distillate consumption and propane consumption, primarily for space heating, decline by 2.7%/year and 2.0%/year, respectively, in the Reference case from 2013 to 2040. The declines are even larger in the High Oil Price case, at 3.1%/year and 2.3%/year for distillate and propane, respectively, over the same period.

End-use energy intensity, as measured by consumption per residential household or square foot of commercial floorspace, decreases in the Reference case as a result of increases in the efficiency of equipment for many end uses (Figure 16 and Figure 17). Federal standards and voluntary market transformation programs (e.g., Energy Star) target uses such as space heating and cooling, water heating, lighting, and refrigeration, as well as devices that are rapidly proliferating, such as set-top boxes and external power supplies.

As a result of collaboration among industry, efficiency advocates, and government, a voluntary agreement for set-top boxes has been issued in lieu of federal standards.[23] Commercial refrigeration standards that will affect walk-in and reach-in coolers and freezers are under discussion among stakeholders.[24] As more states adopt new building codes, shell efficiencies of newly constructed buildings are improving, which will reduce future energy use for heating and cooling in the residential and commercial sectors.

In the AEO2015 Reference case, residential and commercial energy intensities for miscellaneous electric loads (MEL) and nonelectric miscellaneous uses in 2040 are roughly 18% and 23% higher, respectively, than they were in 2013. These devices and appliances vary greatly in their energy use characteristics, and their total energy consumption is closely tied to their levels of

Table 4. Residential households and commercial indicators in three AEO2015 cases, 2013 and 2040

Indicator	2013	2040	Average annual growth rate, 2013-40 (percent per year)
Residential households (millions)			
High Economic Growth	114.3	158.5	1.2
Reference	114.3	141.0	0.8
Low Economic Growth	114.3	127.9	0.4
Commercial floorspace (billion square feet)			
High Economic Growth	82.8	112.4	1.1
Reference	82.8	109.1	1.0
Low Economic Growth	82.8	106.0	0.9

[23]*Following a consensus agreement among manufacturers and industry representatives that is expected to achieve significant energy savings, the* U.S. Department of Energy (DOE) has withdrawn its proposed rulemaking for set-top boxes. See https://www.federalregister.gov/articles/text/raw_text/201/331/264.txt.

[24]Walk-in coolers and walk-in freezer panels, doors, and refrigeration systems are currently scheduled to comply with the updated standard beginning in August 2017 (see http://www1.eere.energy.gov/buildings/appliance_standards/product.aspx/productid/26), and DOE has denied a petition from the Air-Conditioning, Heating, and Refrigeration Institute (AHRI) to reconsider its final rulemaking (see http://www.energy.gov/sites/prod/files/2014/09/f18/petition_denial.pdf).

penetration and saturation in the buildings sectors. As a result, MEL and nonelectric miscellaneous uses are difficult targets for federal efficiency standards.[25]

Penetration of grid-connected distributed generation continues to grow as both equipment and non-equipment costs decline, slowing delivered electricity demand growth in both residential and commercial buildings. In the AEO2015 Reference case, solar photovoltaic (PV) capacity in the residential sector grows by an average of about 30%/year from 2013 through 2016, compared with 9%/year for commercial sector PV, driven by the recent popularity of third-party leasing and other innovative financing options and tax credits. Following expiration of the 30% federal investment tax credit at the end of 2016, the average annual growth of PV capacity in residential and commercial buildings slows to about 6% in both sectors through 2040.

Natural gas CHP capacity in the commercial sector grows by an average of 9%/year from 2013 to 2040 in the Reference case and shows little variation across the alternative cases. Although natural gas prices are lower in the High Oil and Gas Resource case than in the Reference case, lower electricity prices limit the attractiveness of commercial CHP relative to purchased electricity.

Figure 16. Residential sector delivered energy intensity for selected end uses in the Reference case, 2013 and 2040 (million Btu per household per year)

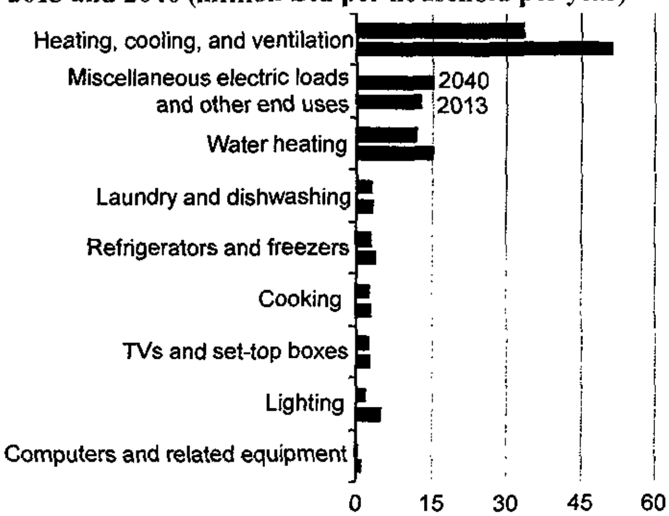
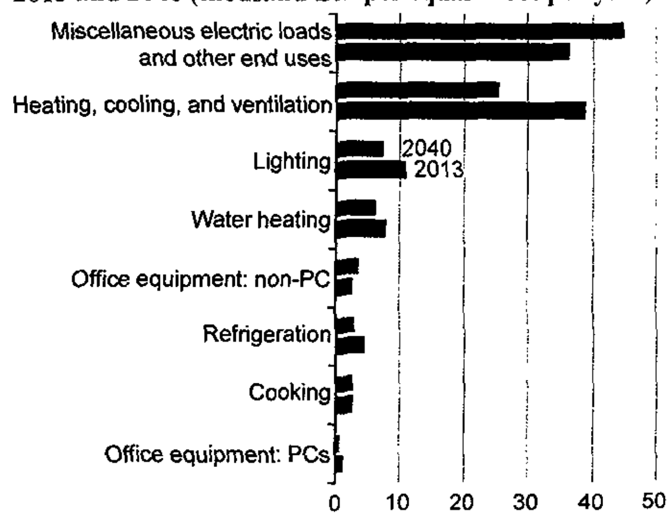


Figure 17. Commercial sector delivered energy intensity for selected end uses in the Reference case, 2013 and 2040 (thousand Btu per square foot per year)

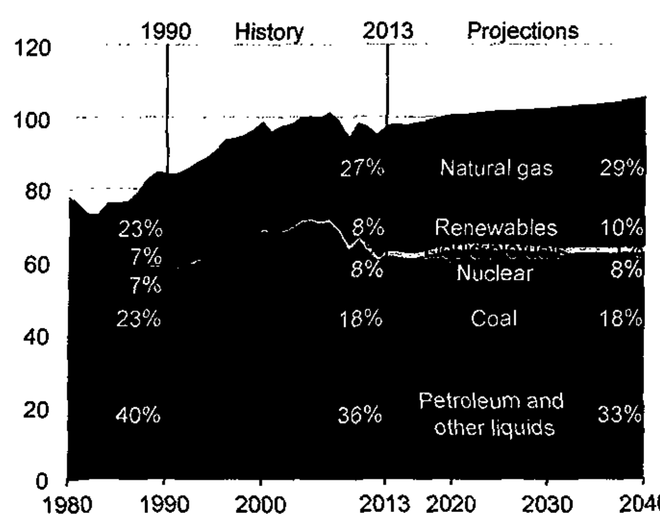


Energy consumption by primary fuel

Total primary energy consumption grows in the AEO2015 Reference case by 8.6 quadrillion Btu (8.9%), from 97.1 quadrillion Btu in 2013 to 105.7 quadrillion Btu in 2040 (Figure 18). Most of the growth is in consumption of natural gas and renewable energy. Consumption of petroleum products across all sectors in 2040 is unchanged from 2013 levels, as motor gasoline consumption in the transportation sector declines as a result of a 70% increase in the average efficiency of on-road light-duty vehicles (LDVs), to 37 mpg in 2040, which more than offsets projected growth in vehicle miles traveled (VMT). Total motor gasoline consumption in the transportation sector is about 3.4 quadrillion Btu (1.8 million barrels per day (bbl/d)) lower in 2040 than in 2013, and total petroleum consumption in the transportation sector is about 1.6 quadrillion Btu (0.9 million bbl/d) lower in 2040 than in 2013.

U.S. consumption of petroleum and other liquids, which totaled 35.9 quadrillion Btu (19.0 million bbl/d) in 2013, increases to 37.1 quadrillion Btu (19.6 million bbl/d) in 2020, then declines to 36.2 quadrillion Btu (19.3 million bbl/d) in

Figure 18. Primary energy consumption by fuel in the Reference case, 1980-2040 (quadrillion Btu)



[25]Navigant Consulting Inc. and Leidos—formerly SAIC, *Analysis and Representation of Miscellaneous Electric Loads in NEMS*, prepared for the U.S. Energy Information Administration (Washington, DC: May 2013), http://www.eia.gov/analysis/studies/demand/miscelectric/.

2040. In the transportation sector, which continues to dominate demand for petroleum and other liquids, there is a shift from motor gasoline to distillate. The gasoline share of total demand for transportation petroleum and other liquids declines by 10.6 percentage points, while distillate consumption increases by 7.2 percentage points. Increased use of compressed natural gas and LNG in vehicles also replaces about 3% of petroleum and other liquids consumption in the transportation sector in 2040. Consumption of ethane and propane (the latter including propylene), which are used in chemical production, shows the largest increase of all petroleum products in the AEO2015 Reference case from 2013 to 2040. Industrial consumption of ethane and propane, extracted from wet gas in natural gas processing plants, grows by almost 1 quadrillion Btu (790 thousand bbl/d) as dry natural gas production increases.

Natural gas consumption in the AEO2015 Reference case increases from 26.9 quadrillion Btu (26.2 Tcf) in 2013 to 30.5 quadrillion Btu (29.7 Tcf) in 2040. The largest share of the growth is for electricity generation in the electric power sector, where demand for natural gas grows from 8.4 quadrillion Btu (8.2 Tcf) in 2013 to 9.6 quadrillion Btu (9.4 Tcf) in 2040, in part as a result of the retirement of 40.1 GW of coal-fired capacity by 2025. Natural gas consumption in the industrial sector also increases, rapidly through 2016 and then more slowly through 2040, benefiting from the increase in shale gas production that is accompanied by slower growth of natural gas prices. Industries such as bulk chemicals, which use natural gas as a feedstock, are more strongly affected than others. Natural gas use as a feedstock in the chemical industry increases by about 0.4 quadrillion Btu from 2013 to 2040. In the residential sector, natural gas consumption declines from 2018 to 2040 and it increases slightly in the commercial sector over the same period.

Coal use in the Reference case grows from 18.0 quadrillion Btu (925 million short tons) in 2013 to 19.0 quadrillion Btu (988 million short tons) in 2040. As previously noted, the Reference case and other AEO2015 cases do not include EPA's proposed Clean Power Plan, which if it is implemented is likely to have a significant effect on coal use. Coal use in the industrial sector falls off slightly over the projection period, as steel production becomes more energy efficient. On the other hand, if oil prices were significantly higher than projected in the Reference case, coal could be used to make liquids via the Fischer-Tropsch process. In the High Oil Price case—the only AEO2015 case in which coal-to-liquids (CTL) technology becomes economically viable—liquids production from CTL plants totals about 710,000 bbl/d in 2040, representing about 3.3 quadrillion Btu (including liquids value), or about 180 million short tons, of coal consumption.

Consumption of marketed renewable energy increases by about 3.6 quadrillion Btu in the Reference case, from 9.0 quadrillion Btu in 2013 to 12.5 quadrillion Btu in 2040, with most of the growth in the electric power sector. Hydropower, the largest category of renewable electricity generation in 2013, contributes little to the increase in renewable fuel consumption. Wind-powered generation, the second-largest category of renewable electricity generation in 2013, becomes the largest contributor in 2038 (including wind generation by utilities and end-users onsite). However, solar photovoltaics (6.8%/year), geothermal (5.5%/year), and biomass (3.1%/year) all increase at faster average annual rates than wind (2.4%/year), including all sectors. Modest penetration of E85 and a small increase in liquids blended into diesel fuel result in a slight increase in consumption of renewable liquid fuels for transportation, despite a smaller pool for ethanol blending as a result of a projected overall decrease in motor gasoline consumption in the AEO2015 Reference case.

In the High Oil Price case, total primary energy use in 2040 is 109.7 quadrillion Btu, 3.9 quadrillion Btu higher than in the Reference case, even though total liquids consumption in 2040 is 3.3 quadrillion Btu lower, despite an 0.3 quadrillion Btu increase in renewable liquids. The decrease in petroleum and other liquids consumption is more than offset by increased consumption of natural gas (31.8 quadrillion Btu in 2040, 1.3 quadrillion Btu more than in the Reference case), coal (21.6 quadrillion Btu in 2040, 2.6 quadrillion Btu more, not including the Fischer-Tropsch coal consumed as liquids), nuclear (9.8 quadrillion Btu in 2040, 1.1 quadrillion Btu more), and many renewables (13.2 quadrillion Btu in 2040, 2.3 quadrillion Btu more, not including consumption of liquids from renewable fuels). The increases in coal and natural gas consumption are explained by the attractiveness of turning them into liquid fuels, made profitable by higher oil prices despite lower demand for motor gasoline and diesel fuels.

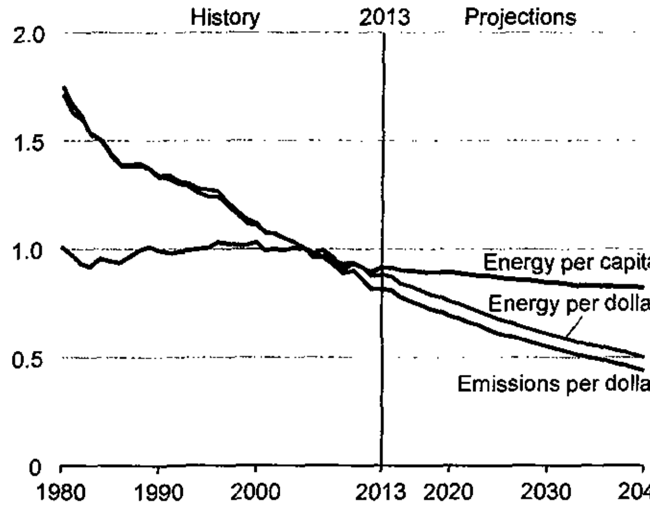
Uncertainty about economic growth results in the widest variation in the projections for total primary energy consumption in 2040, ranging from 98.0 quadrillion Btu in the Low Economic Growth case (1.8% average annual growth in real GDP measured in 2009 dollars) to 116.2 quadrillion Btu in the High Economic Growth case (2.9% average annual growth in real GDP). Changes in the assumed rate of economic growth lead to variations in the growth of energy consumption across all fuels, whereas changes in crude oil prices or in the size of the oil and natural gas resource base result in shifts among the fuel types consumed, with some fuels gaining share and others losing share. In the Low Oil Price case, the petroleum and other liquids share of total energy consumption is about 36.4% in 2040; in the High Oil Price case, it is 30.0% in the same year. With cheaper natural gas in the High Oil and Gas Resource case, less electricity is generated from coal and renewable fuels.

Energy intensity

Energy intensity (measured both by energy use per capita and by energy use per dollar of GDP) declines in the AEO2015 Reference case over the projection period (Figure 19). While a portion of the decline results from a small shift from energy-intensive to nonenergy-intensive manufacturing, most of it results from changes in other sectors.

Increasing energy efficiency reduces the energy intensity of many residential end uses between 2013 and 2040. Total energy consumption for space heating is 4.2 quadrillion Btu in 2040, 1.7 quadrillion Btu (57%) lower than it was in 2013, despite a 23% increase in the number of households and an 11% increase in the average size (square feet) of a household. Energy use for lighting is 0.8 quadrillion Btu in 2040, 1.0 quadrillion Btu lower than it was in 2013 reflecting a 57% decline in energy use despite an increase in lighting services. Energy use for computers and related equipment is 0.1 quadrillion Btu, 0.2 quadrillion Btu lower than it was in 2013. Improved efficiency also reduces delivered energy use in the transportation sector from 27.0 quadrillion Btu in 2013 to 26.5 quadrillion Btu in 2040, by 0.5 quadrillion Btu, as motor gasoline consumption declines by 3.4 quadrillion Btu. The result is an average annual reduction in energy use per capita of 0.4%/year from 2013 through 2040 and an average annual decline in energy use per 2009 dollar of GDP of 2.0%/year. As renewable fuels and natural gas account for larger shares of total energy consumption, carbon intensity (CO2 emissions per unit of GDP) declines by 2.3%/year from 2013 to 2040.

Figure 19. Energy use per capita and per 2009 dollar of gross domestic product, and carbon dioxide emissions per 2009 dollar of gross domestic product, in the Reference case, 1980-2040 (index, 2005 = 1.0)



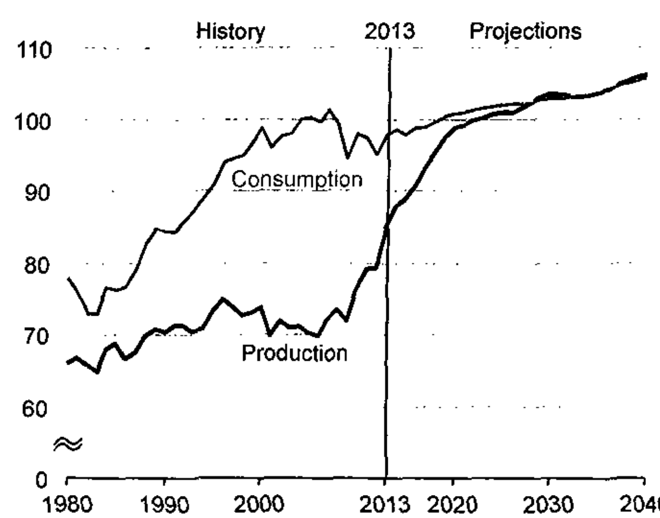
Macroeconomic growth has the largest impact on energy intensity among the AEO2015 alternative cases. Real GDP grows by an average of 1.8%/year from 2013 to 2040 in the Low Economic Growth case, and population grows by an average of 0.6%/year over the same period. Even though energy use increases only slightly (growing by 0.9 quadrillion Btu from 2013 to 2040) because GDP growth is lower than in the other cases, energy intensity as measured in relationship to GDP declines the least—an average rate of 1.8% per year from 2013 to 2040. However, the same case shows the largest decline in energy use per person, averaging 0.5%/year from 2013 to 2040. In the High Economic Growth case, real GDP increases at an average annual rate of 2.9%/year, population grows at an average annual rate of 0.8%/year, and energy use increases at an average annual rate of 0.7%/year from 2013 to 2040. As a result, the energy intensity of GDP declines at a slightly higher rate than in the Reference case, while the decline in energy use per person is slower than in the Reference case.

Energy production, imports, and exports

Net U.S. imports of energy declined from 30% of total energy consumption in 2005 to 13% in 2013, as a result of strong growth in domestic oil and dry natural gas production from tight formations and slow growth of total energy consumption. The decline in net energy imports is projected to continue at a slower rate in the AEO2015 Reference case, with energy imports and exports coming into balance around 2028 (although liquid fuel imports continue, at a reduced level, throughout the Reference case). From 2035 to 2040, energy exports account for about 23% of total annual U.S. energy production in the Reference case (Figure 20). Economic growth has a major influence on U.S. energy consumption, imports, and exports. In the High Economic Growth case, the United States remains a net energy importer through 2040, with net imports equal to about 3% of consumption in 2040. In the Low Economic Growth case, the United States becomes a net exporter of energy in 2022, with energy exports equal to 4% of total domestic energy production in 2040.

Changes in the world oil price affect both consumption and production, but in opposite directions from the effects of changes in U.S. economic growth. Higher world oil prices place downward pressure on consumption while making domestic production more profitable. In the Low Oil Price case, with lower domestic production and higher U.S. energy consumption, the United States remains a net energy importer, with imports increasing every year from 2033 to 2040 and net imports equal to 9% of total domestic energy

Figure 20. Total energy production and consumption in the Reference case, 1980-2040 (quadrillion Btu)



consumption in 2040. In the High Oil Price case, with stronger growth in production and more incentives for energy efficiency, the United States becomes and remains a net energy exporter starting in 2019, and net exports increase to 9% of total energy production in 2040 after peaking at 11% in 2032. In the High Oil and Gas Resource case, with faster growth in domestic natural gas and crude oil production, U.S. net energy exports, mostly in the form of petroleum and natural gas, grow to almost 19% of total domestic energy production in 2040.

Petroleum and other liquids

Production from tight formations leads the growth in U.S. crude oil production across all AEO2015 cases. The path of projected crude oil production varies significantly across the cases, with total U.S. crude oil production reaching high points of 10.6 million barrels per day (bbl/d) in the Reference case (in 2020), 13.0 million bbl/d in the High Oil Price case (in 2026), 16.6 million bbl/d in the High Oil and Gas Resource case (in 2039), and 10.0 million bbl/d in the Low Oil Price case (in 2020).

In the Reference case, the existing U.S. competitive advantage in oil refining compared to the rest of the world continues over the projection period. This advantage results in growing gasoline and diesel exports through 2040 in the Reference case. The production of motor gasoline blending components, which totaled 7.9 million bbl/d in 2013, begins declining in 2015 and falls to 7.2 million bbl/d by the end of the projection period, while diesel fuel production rises from 4.2 million bbl/d in 2013 to 5.3 million bbl/d in 2040. As a result of declining consumption of liquid fuels and increasing production of domestic crude oil, net imports of crude oil and petroleum products fall from 6.2 million bbl/d in 2013 (33% of total domestic consumption) to 3.3 million bbl/d in 2040 (17% of domestic consumption) in the Reference case. Growth in gross exports of refined petroleum products, particularly of motor gasoline and diesel fuel, results in a significant increase in net petroleum product exports between 2013 and 2040.

In both the High Oil and Gas Resource and High Oil Price cases, total U.S. crude oil production is higher than in the Reference case mainly as a result of growth in tight oil production, which rises at a substantially faster rate in the near term in both cases than in the Reference case. In the High Oil and Gas Resource case, tight oil production grows in response to assumed higher estimated ultimate recovery (EUR) and technology improvements, closer well spacing, and development of new tight oil formations or additional layers within known tight oil formations. Total crude oil production reaches 16.6 million bbl/d in 2037 in the High Oil and Gas Resource case. In the High Oil Price case, higher oil prices improve the economics of production from new wells in tight formations as well as from other domestic production sources, leading to a more rapid increase in production volumes than in the Reference case. Tight oil production increases through 2022, when it totals 7.4 million bbl/d. After 2022, tight oil production declines, as drilling moves into less productive areas. Total U.S. crude oil production reaches 13.0 million bbl/d by 2025 in the High Oil Price case before declining to 9.9 million bbl/d in 2040 (Figure 21 and Figure 22).

Recent declines in West Texas Intermediate[26] oil prices (falling by 59% from June 2014 to January 2015) have triggered interest in the effect of lower prices on U.S. oil production. In the Low Oil Price case, domestic crude oil production is 9.8 million bbl/d in 2022, 0.7 million bbl/d lower than the 10.4 million bbl/d in the Reference case. In 2040, U.S. crude oil production is 7.1 million bbl/d, 2.3 million bbl/d lower than the 9.4 million bbl/d in the Reference case. Most of the difference in total crude oil production levels between the Reference and Low Oil Price cases reflects changes in production from tight oil formations. However, all sources of U.S. oil production are adversely affected by low oil prices. As crude oil prices fall and remain at or below $76/ barrel (Brent) in the Low Oil Price case after 2014, poor investment returns lead to fewer wells being drilled in noncore areas of

Figure 21. U.S. tight oil production in four cases, 2005-40 (million barrels per day)

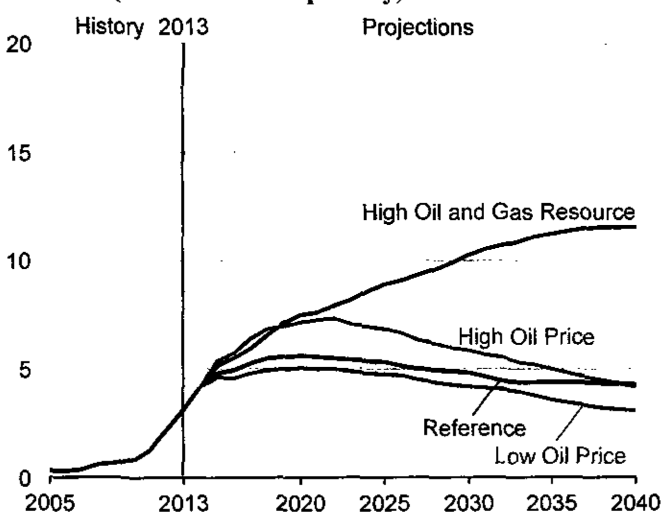
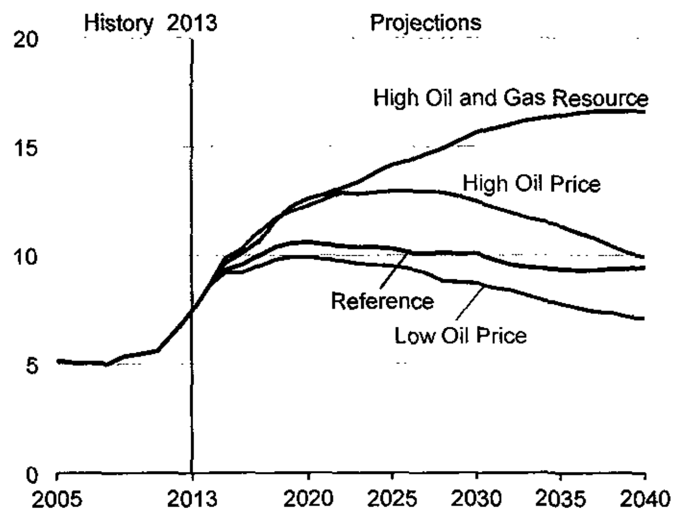


Figure 22. U.S. total crude oil production in four cases, 2005-40 (million barrels per day)



[26]West Texas Intermediate is a crude stream produced in Texas and southern Oklahoma that serves as a reference, or marker, for pricing a number of other crude streams and is traded in the domestic spot market at Cushing, Oklahoma.

formations, which have smaller estimated ultimate recoveries (EURs) than wells drilled in core areas. As a result, they have a more limited impact on total production growth in the near term.

In both the High Oil and Gas Resource and High Oil Price cases, growing production of 27°-35° American Petroleum Institute (API) medium sour crude oil from the offshore Gulf of Mexico (GOM) helps balance the crude slate when combined with the increasing production of light, sweet crude from tight oil formations. In all cases, GOM crude oil production increases through 2019, as offshore deepwater projects have relatively long development cycles that have already begun. GOM production declines through at least 2025 in all cases and fluctuates thereafter as a result of the timing of large, discrete discoveries that are brought into production. Overall GOM production through 2040 is highest in the High Oil and Gas Resource case, followed closely by the High Oil Price case and finally by the Reference case and Low Oil Price case.

In the High Oil Price case, producers take greater advantage of CO2-enhanced oil recovery (CO2-EOR) technologies. CO2-EOR production increases at a steady pace over the projection period in the Reference case and increases more dramatically in the High Oil Price case, where higher prices make additional CO2-EOR projects economically viable. In the High Oil and Gas Resource and Low Oil Price cases, with lower crude oil prices, fewer CO2-EOR projects are economical than in the Reference case.

Production of natural gas plant liquids (NGPL), including ethane, propane, butane, isobutane, and natural gasoline, increases from 2013 to 2023 in all the AEO2015 cases. After 2023, only the High Oil and Gas Resource case shows increasing NGPL production through the entire projection period. However, the High Oil Price case also shows significant NGPL production growth through 2026. Most of the early growth in NGPL production is associated with the continued development of liquids-rich areas in the Marcellus, Utica, and Eagle Ford formations.

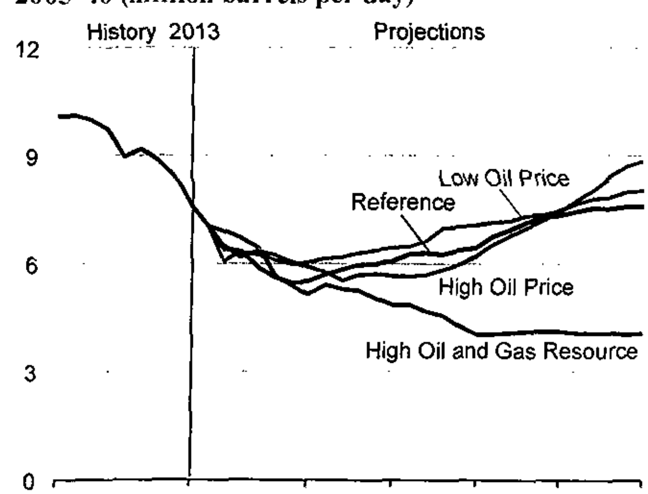
Production of petroleum products at U.S. refineries depends largely on the cost of crude oil, domestic demand, and the absorption of petroleum product exports in foreign markets. U.S. refinery production of gasoline blending components declines in the Reference and Low Oil Price cases but increases in the High Oil Price and High Oil and Gas Resource cases. The steepest decline in production of motor gasoline blending components is projected in the Reference case, with production of blending components declining from 7.9 million bbl/d in 2013 to 7.2 million bbl/d in 2040, in response to a drop in U.S. crude oil production, higher crude oil prices, and lower demand. In the High Oil and Gas Resource case, production of blending components increases to 9.1 million bbl/d in 2040, because abundant domestic supply of lighter crude oil results in lower feedstock costs for refiners, lower gasoline prices, increased exports, and relatively higher levels of gasoline consumption (including exports) and production.

Diesel fuel output from U.S. refineries rises in the High Oil and Gas Resource case from 4.2 million bbl/d in 2013 to 6.6 million bbl/d in 2037, as a result of lower costs for refinery feedstocks. In the Low Oil Price case, lower domestic diesel fuel prices result in higher levels of domestic consumption, leading to a 4.7 million bbl/d increase in diesel fuel production in 2040. In the High Oil Price case, higher oil prices (which are assumed to occur worldwide) make diesel fuel from U.S. refineries more competitive. Total U.S. diesel fuel output increases to 6.1 million bbl/d in 2040. In the Reference case, U.S. diesel fuel output increases to 5.3 million bbl/d in 2040.

As in the Reference case, the United States remains a net importer of liquid fuels through 2040 in the Low Oil Price case. In the High Oil and Gas Resource case, as a result of higher levels of both domestic crude oil production and petroleum product exports, the United States becomes a net exporter of liquid fuels by 2021. Refiners and oil producers gain a competitive advantage from abundant domestic supply of light crude oil and higher GOM production of lower API crude oil streams, along with lower refinery fuel costs as a result of abundant domestic natural gas supply. In the High Oil Price case, the United States becomes a net exporter of liquid fuels in 2020, as higher oil prices reduce U.S. consumption of petroleum products and spur additional U.S. crude oil production. U.S. net crude oil imports—which fall to 5.5 million bbl/d in 2022 as domestic crude oil production grows—rise to 8.9 million bbl/d in 2040 as domestic production flattens and begins to decline.

By 2040, the level of net liquid fuels exports is significantly larger in the High Oil and Gas Resource case than in the High Oil Price case. In the High Oil Price case, higher world crude oil prices make overseas refineries less competitive compared to U.S. refineries. As a result, net U.S. exports of petroleum products increase by more in the High Oil Price case than in the High Oil and Gas Resource case. However, the availability of more domestic crude oil resources in the High Oil and Gas Resource case results in a significantly greater drop in net crude oil imports and a larger overall swing in liquid fuels trade than in any of the other AEO2015 cases (Figure 23 and Figure 24).

Figure 23. U.S. net crude oil imports in four cases, 2005-40 (million barrels per day)



In the High Oil and Gas Resource case, the United States swings from net liquid fuels imports equal to 33% of total domestic product supplied in 2013 to net liquid fuels exports equal to 29% of total domestic product supplied in 2040 (compared with net exports equal to 3% of total domestic product supplied in 2040 in the High Oil Price case). In the Reference case, net imports fall to 14% of total domestic product supplied in 2020, before rising to nearly 18% of product supplied in 2033 and remaining around that level through 2040. Net imports of liquid fuels fall to 19% of total product supplied in 2020 in the Low Oil Price case before rising to 36% of total product supplied in 2040.

Cheaper light crude oil production from inland basins and increased production of heavier GOM crude oil leads to a 35% decline in gross crude oil imports in the High Oil and Gas Resource case—from 7.7 million bbl/d in 2013 to 5.0 million bbl/d in 2040. This compares with a 6% increase in the Reference case (to 8.2 million bbl/d in 2040) and a 12% increase in the Low Oil Price case (to 8.7 million bbl/d in 2040).

Net petroleum product exports increase as U.S. refineries become more competitive in all cases except for the Low Oil Price case. Net petroleum product exports increase most in the High Oil Price and High Oil and Gas Resource cases (from 1.4 million bbl/d in 2013 to 9.5 million bbl/d and 9.9 million bbl/d, respectively, in 2040). In the Reference case, net petroleum product exports increase to 4.3 million bbl/d in 2040, and in the Low Oil Price case they increase to 2.2 million bbl/d in 2020 and then decline to 0.7 million bbl/d in 2040.

In the High Oil and Gas Resource case, gross crude oil exports allowed under current laws and regulations, including exports to Canada and exports of processed condensate, rise significantly in response to increased production. It is assumed that condensate which has been processed through a distillation tower can be exported in accordance with a clarification from the U.S. Department of Commerce, Bureau of Industry and Security.[27] Gross crude exports increase from 0.1 million bbl/d in 2013 to a high of 1.3 million bbl/d in 2027 in the High Oil and Gas Resource case, before declining to 0.9 million bbl/d in 2040—compared with 0.6 million bbl/d in 2040 in the Reference, High Oil Price, and Low Oil Price cases. With U.S. refinery access to increased amounts of low-cost domestic crude supplies, gross petroleum product exports increase from 3.4 million bbl/d in 2013 to 12.0 million bbl/d in the High Oil and Gas Resource case and to 11.5 million bbl/d in 2040 in the High Oil Price case, compared with 6.4 million bbl/d in the Reference case and 3.5 million bbl/d in the Low Oil Price case.

Natural gas

Production

Total dry natural gas production in the United States increased by 35% from 2005 to 2013, with the natural gas share of total U.S. energy consumption rising from 23% to 28%. Production growth resulted largely from the development of shale gas resources in the Lower 48 states (including natural gas from tight oil formations), which more than offset declines in other Lower 48 onshore production. In the AEO2015 Reference case, more than half of the total increase in shale gas production over the projection period comes from the Haynesville and Marcellus formations. Lower 48 shale gas production (including natural gas from tight oil formations) increases by 73% in the Reference case, from 11.3 Tcf in 2013 to 19.6 Tcf in 2040, leading to a 45% increase in total U.S. dry natural gas production, from 24.4 Tcf in 2013 to 35.5 Tcf in 2040. Growth in tight gas, federal offshore, and onshore Alaska production also contributes to overall production growth over the projection period (Figure 25 and Figure 26).

Figure 24. U.S. net petroleum product imports in four cases, 2005-40 (million barrels per day)

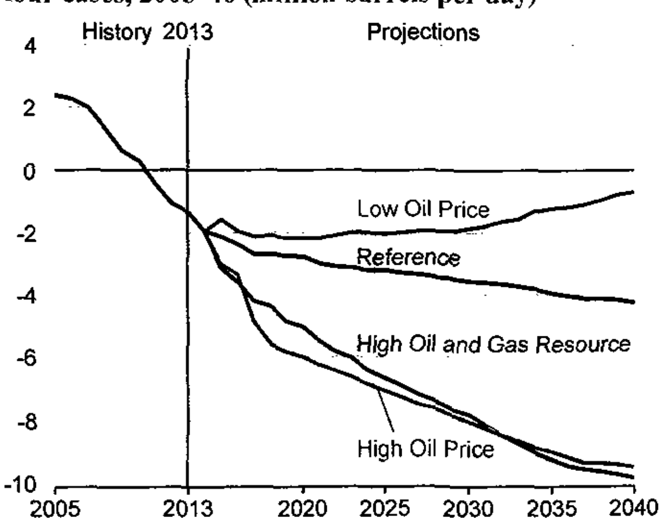
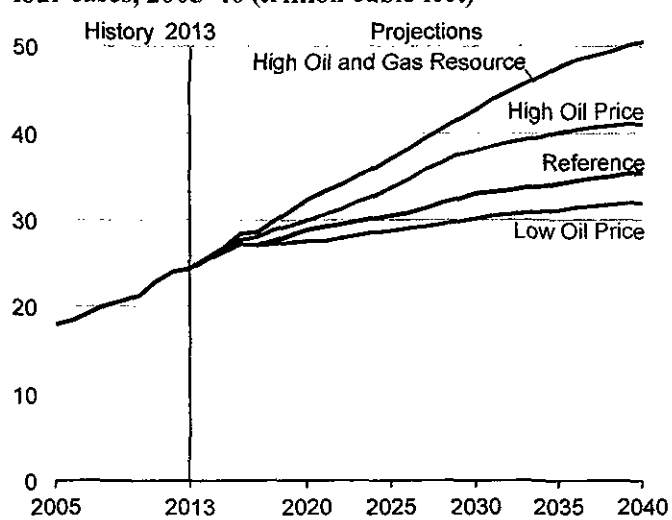


Figure 25. U.S. total dry natural gas production in four cases, 2005-40 (trillion cubic feet)



[27] U.S. Department of Commerce, Bureau of Industry and Security, "FAQs-Crude Oil and Petroleum Products December 30, 2014" (see question no. 3, "Is lease condensate considered crude oil?") (Washington, DC: December 30, 2014), http://www.bis.doc.gov/index.php/policy-guidance/faqs.

Future dry natural gas production depends primarily on the size and cost of tight and shale gas resources, technology improvements, domestic natural gas demand, and the relative price of oil. Projections in the High Oil and Gas Resource case assume closer well spacing; higher EURs per shale gas well, tight gas well, and tight oil well; development of new tight oil formations either from new discoveries or additional layers within known tight oil formations; and additional long-term technology improvements that further increase the EUR per tight gas and shale gas well over the projection period above those in the Reference case. Even with lower prices, total U.S. dry natural gas production increases in the High Oil and Gas Resource case to 50.6 Tcf in 2040, 43% above the Reference case level, with Lower 48 shale gas production of 34.6 Tcf in 2040, or 77% above the Reference case level.

The High and Low Oil Price cases use the same natural gas resource assumptions as the Reference case, but production levels vary in response to natural gas demand, primarily from the transportation sector and global demand for U.S.-origin LNG. In the High Oil Price case, increased demand for natural gas as a fuel for motor vehicles, as LNG for export, and as plant fuel for natural gas liquefaction facilities accounts for the increase in total domestic dry natural gas production to 41.1 Tcf in 2040 (16% above the Reference case). U.S. shale gas production in the High Oil Price case totals 23.6 Tcf in 2040, 21% above the Reference case total. In the Low Oil Price case, with lower demand for natural gas and LNG exports, U.S. dry natural gas production totals 31.9 Tcf in 2040 (10% below the Reference case total), and U.S. shale gas production totals 18.1 Tcf in 2040 (8% below the Reference case).

Tight gas accounts for a smaller, but still significant, portion of the increase in U.S. dry natural gas production compared to shale gas. Tight gas production responds largely to crude oil prices and the same levels of technological progress experienced with shale gas production. Tight gas production increases from 4.4 Tcf in 2013 to 7.0 Tcf in 2040 in the Reference case, compared with 8.1 Tcf in 2040 in the High Oil and Gas Resource case, 8.4 Tcf in the High Oil Price case, and 6.6 Tcf in the Low Oil Price case. Most of the tight gas production growth occurs in the Gulf Coast and Dakotas/Rocky Mountains regions. Tight gas production in the Midcontinent region—which declines in the Reference case—increases by 24% from 2013 to 2040 in the High Oil and Gas Resource case.

Undiscovered crude oil and natural gas resources in the federal offshore and Alaska regions are assumed to be 50% higher in the High Oil and Gas Resource case than in the Reference case. Lower 48 offshore natural gas production increases from 1.5 Tcf in 2013 to 3.0 Tcf in 2040 in the High Oil and Gas Resource case, and to 2.8 Tcf in 2040 in both the High Oil Price and Reference cases. Cumulative federal offshore natural gas production is highest in the High Oil Price case, with federal offshore natural gas production increasing more than in any of the other AEO2015 cases through 2036, before declining. Alaska dry natural gas production begins increasing in 2026 in the High Oil Price case, and in 2027 in the Reference case. Alaska dry natural gas production reaches 1.2 Tcf in 2029 and remains at that level through 2040 in the High Oil Price case. Alaskan production reaches 1.1 Tcf in 2040 in the Reference case, following the projected completion of a new LNG export facility in Alaska. In the Low Oil Price and High Oil and Gas Resource cases, lower international natural gas prices make LNG exports from Alaska uneconomical, and Alaska dry natural gas production falls through 2040 as declines in oil production result in decreased use of natural gas for drilling operations.

Imports and exports

In all the AEO2015 cases, net natural gas imports continue to decline through 2040, as they have since 2007. Gross exports of natural gas increase over the period, and gross imports decline. The rate of decline in net imports varies across the cases—depending on assumptions about changes in world oil prices and U.S. natural gas resources—and slows in the later years of the projections (Figure 27). In all the cases, the United States becomes a net exporter of natural gas in 2017, driven by LNG exports (Figure 28), increased pipeline exports to Mexico, and reduced imports from Canada.

Figure 26. U.S. shale gas production in four cases, 2005-40 (trillion cubic feet)

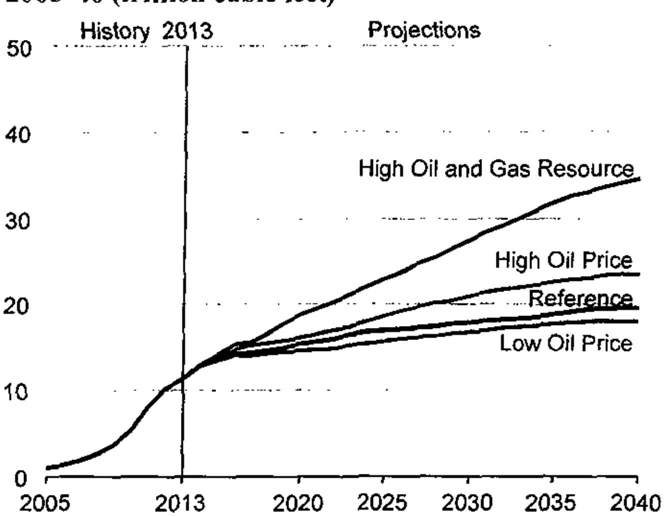
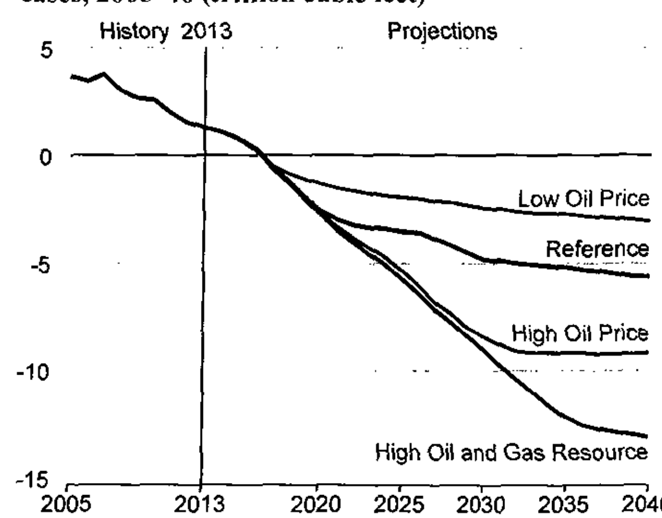


Figure 27. U.S. total natural gas net imports in four cases, 2005-40 (trillion cubic feet)



In the Reference case, net exports of natural gas from the United States total 5.6 Tcf in 2040. Most of the growth in U.S. net natural gas exports occurs before 2030, when gross liquefied natural gas (LNG) exports reach their highest level of 3.4 Tcf, where they remain through 2040. In all the cases, the United States remains a net pipeline importer of natural gas from Canada through 2040, but at lower levels than in recent history, while net pipeline exports of natural gas to Mexico grow from 0.7 Tcf in 2013 to 3.0 Tcf in 2040 in the Reference case.

The price of LNG supplied to international markets, which in part reflects world oil prices, is significantly higher than the price of U.S. domestic natural gas supply, particularly in the near term. The growth in U.S. LNG exports is driven by this price difference, which also discourages U.S. LNG imports. LNG export growth after 2020 is highest in the High Oil and Gas Resource case, where higher production capability lowers the price of U.S. natural gas supply to the world market, leading to net LNG exports of 10.3 Tcf in 2040 (212% more than in the Reference case) and total net natural gas exports of 13.1 Tcf in 2040 (133% more than in the Reference case).

Most of the variations in projected net exports of U.S. natural gas among the AEO2015 cases result from differences in levels of LNG exports. In the High Oil Price and Low Oil Price cases, projected LNG exports vary in response to differences between international and domestic natural gas prices, after accounting for the costs associated with processing and transporting the gas. Over the projection, the relationship between international LNG prices and world oil prices is assumed to weaken, particularly as U.S. LNG exports increase. Low world oil prices limit the competitiveness of domestic natural gas relative to oil itself and also to LNG volumes sold through contracts linked to oil prices, which are less likely to be renegotiated in a low oil price environment.

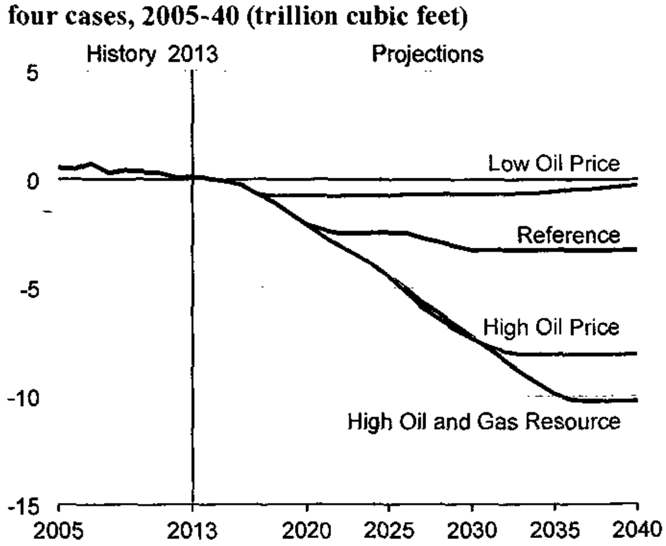
In the High Oil Price case, U.S. LNG exports total 8.1 Tcf in 2040, or 142% more than in the Reference case. As a result, U.S. net natural gas exports total 9.1 Tcf in 2040 in the High Oil Price case, or 63% more than in the Reference case. In the Low World Oil Price case, LNG net exports never surpass 0.8 Tcf, and U.S. net exports of natural gas total 3.0 Tcf in 2040, or 46% below the Reference case level.

Canada, which accounted for 97% of total U.S. pipeline imports of natural gas in 2013, continues as the source of nearly all U.S. pipeline imports through 2040. Most natural gas imported into the United States comes from western Canada and is delivered mainly to the West Coast and the Midwest.

In the AEO2015 alternative cases, gross pipeline imports from Canada generally are higher than in the Reference case when prices in the United States are higher, and vice versa. However, gross pipeline imports from Canada in 2040 are highest in the High Oil and Gas Resource case, with growth after 2030 resulting from an assumed increase in Canada's shale and coalbed resources. Gross exports of U.S. natural gas to Canada, largely into the eastern provinces, generally increase when prices are low in the United States, and vice versa.

U.S. pipeline exports of natural gas—most flowing south to Mexico—have grown substantially since 2010 and are projected to continue increasing in all the AEO2015 cases because increases in Mexico's production are not expected to keep pace with the country's growing demand for natural gas, primarily for electric power generation. In the High Oil and Gas Resource case, with the lowest projected U.S. natural gas prices, pipeline exports to Mexico in 2040 total 4.7 Tcf, as compared with 3.3 Tcf in the Low Oil Price case and 2.2 Tcf by 2040 in the High Oil Price case.

Figure 28. U.S. liquefied natural gas net imports in four cases, 2005-40 (trillion cubic feet)



Coal

Between 2008 and 2013, U.S. coal production fell by 187 million short tons (16%), as declining natural gas prices made coal less competitive as a fuel for generating electricity (Figure 29). In the AEO2015 Reference case, U.S. coal production increases at an average rate of 0.7%/year from 2013 to 2030, from 985 million short tons (19.9 quadrillion Btu) to 1,118 million short tons (22.4 quadrillion Btu). Over the same period, rising natural gas prices, particularly after 2017, contribute to increases in electricity generation from existing coal-fired power plants as coal prices increase more slowly. After 2030, coal consumption for electricity generation levels off through 2040. The cases presented in AEO2015 do not include EPA's proposed Clean Power Plan, which would have a material impact on projected levels of coal-fired generation. A separate EIA analysis of the Clean Power Plan is forthcoming.

Compliance with the Mercury and Air Toxics Standards (MATS),[28] coupled with low natural gas prices and

[28] U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards," http://www.epa.gov/mats (Washington, DC: March 27, 2012).

competition from renewables, leads to the projected retirement of 31 gigawatts (GW) of coal-fired generating capacity and the conversion of 4 GW of coal-fired generating capacity to natural gas between 2014 and 2016. However, coal consumption in the U.S. electric power sector is supported by an increase in output from the remaining coal-fired power plants, with the projected capacity factor for the U.S. coal fleet increasing from 60% in 2013 to 67% in 2016. In the absence of any significant additions of coal-fired electricity generating capacity, coal production after 2030 levels off as many existing coal-fired generating units reach maximum capacity factors and coal exports grow slowly. Total U.S. coal production in the AEO2015 Reference case remains below its 2008 level through 2040.

Across the AEO2015 alternative cases, the largest changes in U.S. coal production relative to the Reference case occur in the High Oil and Gas Resource and High Oil Price cases. In the High Oil and Gas Resource case, lower natural gas prices lead to a significant shift away from the use of coal in the electric power sector, resulting in coal production levels that are 13% lower in 2020 and 11% lower in 2040 than in the Reference case. In the High Oil Price case, higher oil prices spur investments in coal-based synthetic fuels, which result in increasing demand for domestically produced coal, primarily from mines in the Western supply region. In the High Oil Price case, coal consumption at coal-to-liquids (CTL) plants rises from 11 million short tons in 2025 to 181 million short tons in 2040, and total coal production in 2040 is 13% higher than in the Reference case.

In the other AEO2015 cases, variations in the quantities of coal produced relative to the Reference case are more modest, ranging from 4% (49 million short tons) lower in the Low Economic Growth case to 4% (40 million short tons) higher in the High Economic Growth case in 2040. Factors that limit the variation in U.S. coal production across cases include the high capital costs associated with building new coal-fired generating capacity, which limit potential growth in coal use; the relatively low operating costs of existing coal-fired units, which tend to limit the decline in coal use; and limited potential to increase coal use at existing generating units, which already are at maximum utilization rates in some regions.

Changes in assumptions about the rate of economic growth also affect the outlook for coal demand in the U.S. industrial sector (coke and other industrial plants) and, consequently, coal production. In the Low Economic Growth case, lower levels of industrial coal consumption in 2040 account for 17% of the reduction in total coal consumption relative to the Reference case. In the High Economic Growth case, higher levels of coal consumption in the industrial sector in 2040 account for 44% of the increase in total coal consumption relative to the Reference case.

Regionally, strong production growth in the Interior region contrasts with declining production in the Appalachian region in the AEO2015 Reference case. In the Interior region, coal production becomes increasingly competitive as a result of a combination of improving labor productivity and the installation of scrubbers at existing coal-fired power plants, which allows those plants to burn the region's higher-sulfur coals at a lower delivered cost compared with coal from other regions. Appalachian coal production declines in the Reference case, as coal produced from the extensively mined, higher-cost reserves of Central Appalachia is replaced by lower-cost coals from other regions. Western coal production in the Reference case increases from 2017 to 2024, in line with the increase in U.S. consumption, but falls slightly thereafter as a result of competition from producers in the Interior region and limited growth in coal use at existing coal-fired power plants after 2025.

U.S. coal exports decline from 118 million short tons in 2013 to 97 million short tons in 2014 and to 82 million short tons in 2015 in the AEO2015 Reference case, then increase gradually to 141 million short tons in 2040 (Figure 30). Much of the growth in exports after 2015 is attributable to increased exports of steam coal from mines in the Interior and Western regions. Between 2015 and 2040, U.S. steam coal exports increase by 42 million short tons, and coking coal exports increase by 17 million short tons.

Figure 29. U.S. coal production in six cases, 1990-2040 (million short tons)

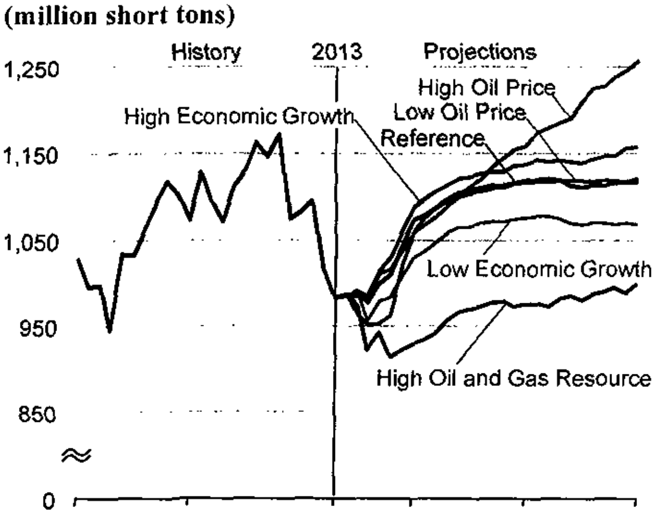
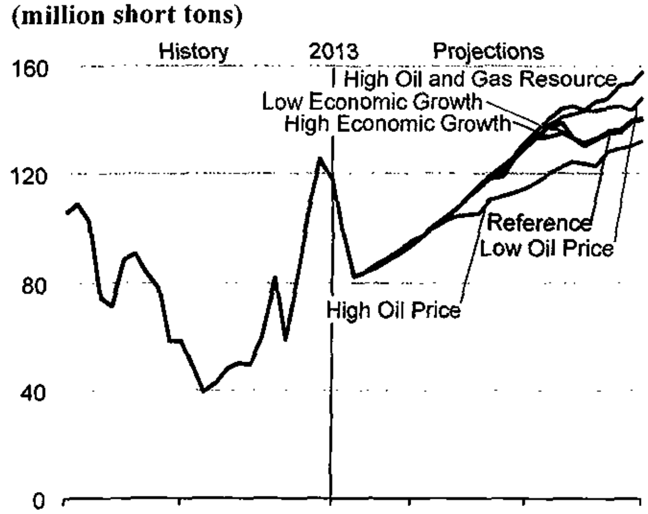


Figure 30. U.S. coal exports in six cases, 1990-2040 (million short tons)



Across the AEO2015 alternative cases, U.S. coal exports in 2040 vary from a low of 132 million short tons in the High Oil Price case (6% lower than in the Reference case) to a high of 158 million short tons in the High Oil and Gas Resource case (12% higher than in the Reference case). Coal exports are also higher in the Low Oil Price case than in the Reference case, increasing to 149 million short tons in 2040. In the Low and High Oil Price cases, variations in the prices of diesel fuel and electricity, which are two important inputs to coal mining and transportation, are key factors affecting U.S. coal exports. The projections of lower and higher fuel prices for coal mining and transportation affect the relative competiveness of U.S. coal in international coal markets. In the High Oil and Gas Resource case, the combination of lower prices for diesel fuel and electricity and lower domestic demand for coal contribute to higher export projections relative to the Reference case.

Electricity generation

Total electricity use in the AEO2015 Reference case, including both purchases from electric power producers and on-site generation, grows by an average of 0.8%/year, from 3,836 billion kilowatthours (kWh) in 2013 to 4,797 billion kWh in 2040. The relatively slow rate of growth in demand, combined with rising natural gas prices, environmental regulations, and continuing growth in renewable generation, leads to tradeoffs between the fuels used for electricity generation. From 2000 to 2012, electricity generation from natural gas-fired plants more than doubled as natural gas prices fell to relatively low levels. In the AEO2015 Reference case, natural gas-fired generation remains below 2012 levels until after 2025, while generation from existing coal-fired plants and new nuclear and renewable plants increases (Figure 31). In the longer term, natural gas fuels more than 60% of the new generation needed from 2025 to 2040, and growth in generation from renewable energy supplies most of the remainder. Generation from coal and nuclear energy remains fairly flat, as high utilization rates at existing units and high capital costs and long lead times for new units mitigate growth in nuclear and coal-fired generation. Considerable variation in the fuel mix results when fuel prices or economic conditions differ from those in the Reference case.

AEO2015 assumes the implementation of the Mercury and Air Toxics Standards (MATS) in 2016, which regulates mercury emissions and other hazardous air pollutants from electric power plants. Because the equipment choices to control these emissions often reduce sulfur dioxide emissions as well, by 2016 sulfur dioxide emissions in the Reference case are well below the levels *required by both the Clean Air Interstate Rule (CAIR)*[29] *and the Cross-State Air Pollution Rule (CSAPR).* [30,31]

Total electricity generation increases by 24% from 2013 to 2040 in the Reference case but varies significantly with different economic assumptions, ranging from a 15% increase in the Low Economic Growth case to a 37% increase in the High Economic Growth case. Coal-fired generation is similar across most of the cases in 2040, except the High Oil and Gas Resource case, which is the only one that shows a significant decline from the Reference case, and the High Oil Price case, which is the only one showing a large increase (Figure 32). The coal share of total electricity generation drops from 39% in 2013 to 34% in 2040 in the Reference

Figure 31. Electricity generation by fuel in the Reference case, 2000-2040 (trillion kilowatthours)

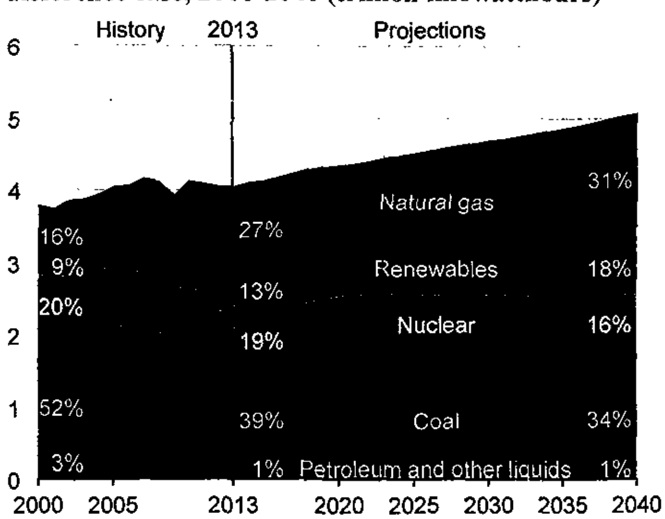
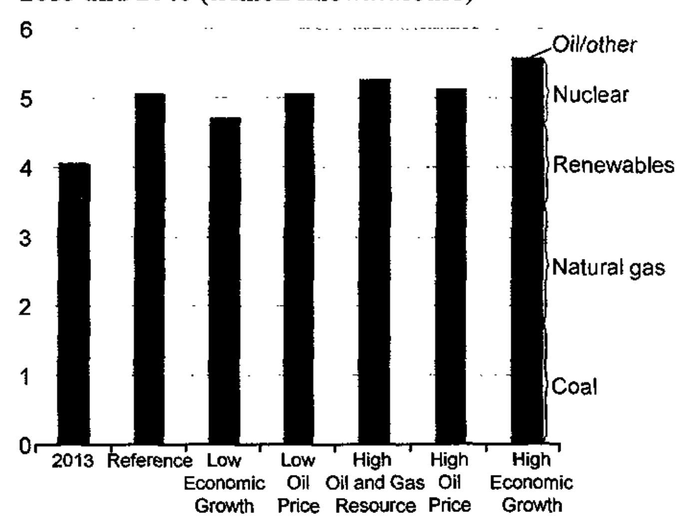


Figure 32. Electricity generation by fuel in six cases, 2013 and 2040 (trillion kilowatthours)



[29]U.S. Environmental Protection Agency, "Clean Air Interstate Rule (CAIR)" (Washington, DC: February 5, 2015), http://www.epa.gov/airmarkets/programs/cair/.

[30]U.S. Environmental Protection Agency, "Cross-State Air Pollution Rule (CSAPR)" (Washington, DC: October 23, 2014), http://www.epa.gov/airtransport/CSAPR.

[31]The AEO2015 Reference case assumes implementation of the Clean Air Interstate Rule (CAIR), which has been replaced by the Cross-State Air Pollution Rule (CSAPR) following a recent D.C. Circuit Court of Appeals decision to lift a stay on CSAPR. Although CAIR and CSAPR are broadly similar, future AEOs will incorporate CSAPR, absent further court action to stay its implementation.

case but still accounts for the largest share of total generation. When natural gas prices are lower than those in the Reference case, as in the High Oil and Gas Resource case, the coal share of total electricity generation drops below the natural gas share by 2020. When total electricity generation is reduced in the Low Economic Growth case, and as a result there is less need for new generation capacity, coal-fired generation maintains a larger share of the total.

Total natural gas-fired generation grows by 40% from 2013 to 2040 in the AEO2015 Reference case—and the natural gas share of total generation grows from 27% to 31%—with most of the growth occurring in the second half of the projection period. The natural gas share of total generation varies by AEO2015 case, depending on fuel prices; however, its growth is also supported by limited potential to increase coal use at existing coal-fired generating units, which in some regions are already at maximum utilization rates. In the High Oil Price case, the natural gas share of total electricity generation in 2040 drops to 23%. In the High Oil and Gas Resource case, with delivered natural gas prices 44% below those in the Reference case, the natural gas share of total generation in 2040 is 42%. Lower natural gas prices in the High Oil and Gas Resource case result in the addition of new natural gas-fired capacity, as well as increased operation of combined-cycle plants, which displace some coal-fired generation. The average capacity factor of natural gas combined-cycle plants is more than 60% in the High Oil and Gas Resource case, compared with an average capacity factor of around 50% in the Reference case (Figure 33), while the average capacity factor of coal-fired plants is lower in the High Oil and Gas Resource case than in the Reference case.

Electricity generation from nuclear units across the cases reflects the impacts of planned and unplanned builds and retirements. Nuclear power plants provided 19% of total electricity generation in 2013. From 2013 to 2040, the nuclear share of total generation declines in all cases, to 15% in the High Oil and Gas Resource case and to 18% in the High Oil Price case, where higher natural gas prices lead to additional growth in nuclear capacity.

Renewable generation grows substantially from 2013 to 2040 in all the AEO2015 cases, with increases ranging from less than 50% in the High Oil and Gas Resource and Low Economic Growth cases to 121% in the High Economic Growth case. State and national policy requirements play an important role in the continuing growth of renewable generation. In the Reference case, the largest growth is seen for wind and solar generation (Figure 34). In 2013, as a result of increases in wind and solar generation, total nonhydropower renewable generation was almost equal to hydroelectric generation for the first time. In 2040, nonhydropower renewable energy sources account for more than two-thirds of the total renewable generation in the Reference case. The total renewable share of all electricity generation increases from 13% in 2013 to 18% in 2040 in the Reference case and to as much as 22% in 2040 in the High Oil Price case. With lower natural gas prices in the High Oil and Gas Resource case, the renewable generation share of total electricity generation grows more slowly but still increases to 15% of total generation in 2040.

Total electricity generation capacity, including capacity in the end-use sectors, increases from 1,065 GW in 2013 to 1,261 GW in 2040 in the AEO2015 Reference case. Over the first 10 years of the projection, capacity additions are roughly equal to retirements, and the level of total capacity remains relatively flat as existing capacity is sufficient to meet expected demand. Capacity additions between 2013 and 2040 total 287 GW, and retirements total 90 GW. From 2018 to 2024, capacity additions average less than 4 GW/year, as earlier planned additions are sufficient to meet most demand growth. From 2025 to 2040, average annual capacity additions—primarily natural gas-fired and renewable technologies—average 12 GW/year. The mix of capacity types added varies across the cases, depending on natural gas prices (Figure 35).

Figure 33. Coal and natural gas combined-cycle generation capacity factors in two cases, 2010-40 (percent)

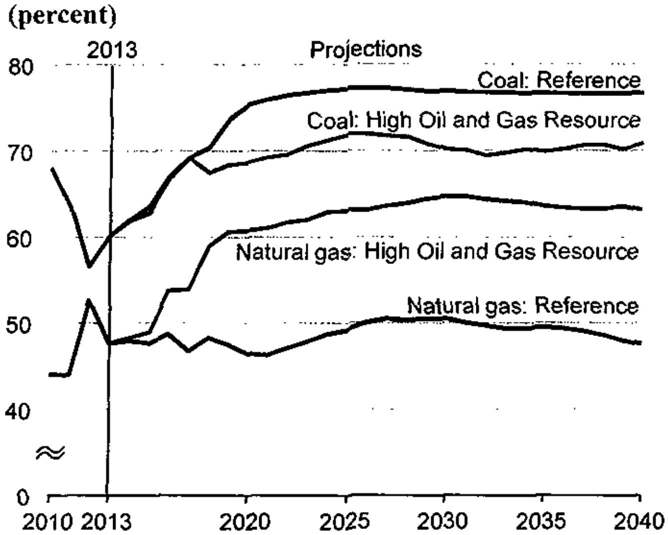


Figure 34. Renewable electricity generation by fuel type in the Reference case, 2000-2040 (billion kilowatthours)

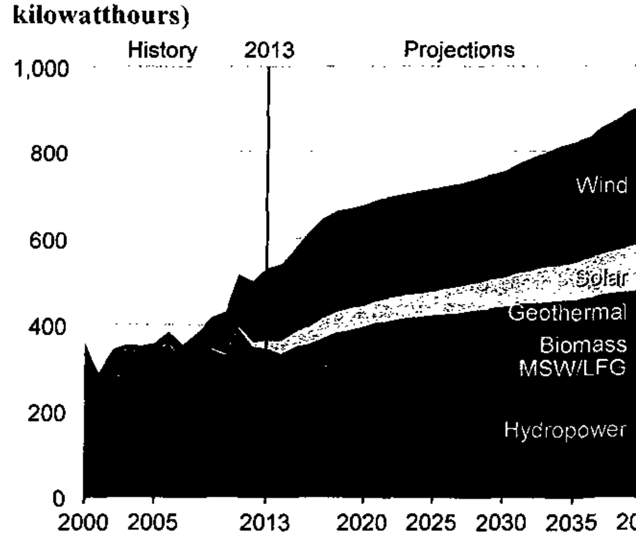
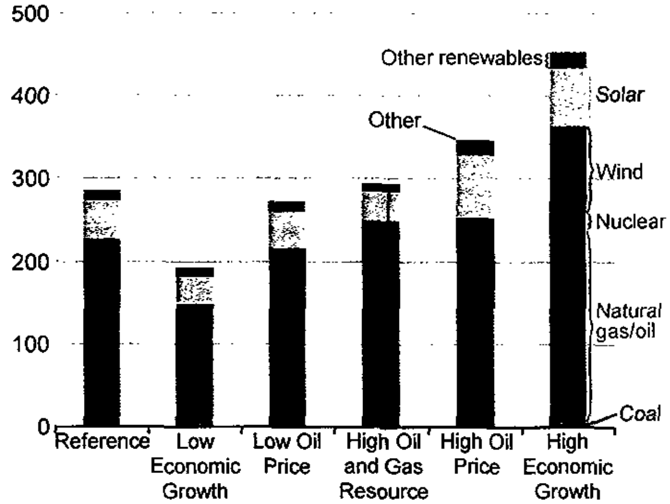


Figure 35. Cumulative additions to electricity generation capacity by fuel in six cases, 2013-40 (gigawatts)



In recent years, natural gas-fired capacity has grown considerably. In particular, combined-cycle plants are relatively inexpensive to build in comparison with new coal, nuclear, or renewable technologies, and they are more efficient to operate than existing natural gas-, oil- or coal-fired steam plants. Natural gas turbines are the most economical way to meet growth for peak demand. In most of the AEO2015 cases, the growth in natural gas capacity continues. Natural gas-fired plants account for 58% of total capacity additions from 2013 to 2040 in the Reference case, and they represent more than 50% of additions in all cases, except for the High Oil Price case, where higher fuel prices for natural gas-fired plants reduce their competitiveness, and only 36% of new builds are gas-fired. With lower fuel prices in the High Oil and Gas Resource case, natural gas-fired capacity makes up three-quarters of total capacity additions.

Coal-fired capacity declines from 304 GW in 2013 to 260 GW in 2040 in the Reference case, as a result of retirements and very few new additions. A total of 40 GW of coal capacity is retired from 2013 to 2040 in the Reference case, representing both announced retirements and those projected on the basis of relative economics, including the costs of meeting environmental regulations and competition with natural gas-fired generation in the near term. As a result of the uncertainty surrounding future greenhouse gas legislation and regulations and given its high capital costs, very little unplanned coal-fired capacity is added across all the AEO2015 cases. About 19 GW of new coal-fired capacity is added in the High Oil Price case, but much of that is associated with CTL plants built in the refinery sector in response to higher oil prices.

Renewables account for more than half the capacity added through 2022, largely to take advantage of the current production tax credit and to help meet state renewable targets. Renewable capacity additions are significant in most of the cases, and in the Reference case they represent 38% of the capacity added from 2013 to 2040. The 109 GW of renewable capacity additions in the Reference case are primarily wind (49 GW) and solar (48 GW) technologies, including 31 GW of solar PV installations in the end-use sectors. The renewable share of total additions ranges from 22% in the High Oil and Gas Resource case to 51% in the High Oil Price case, reflecting the relative economics of natural gas-fired power plants, which are the primary choice for new generating capacity.

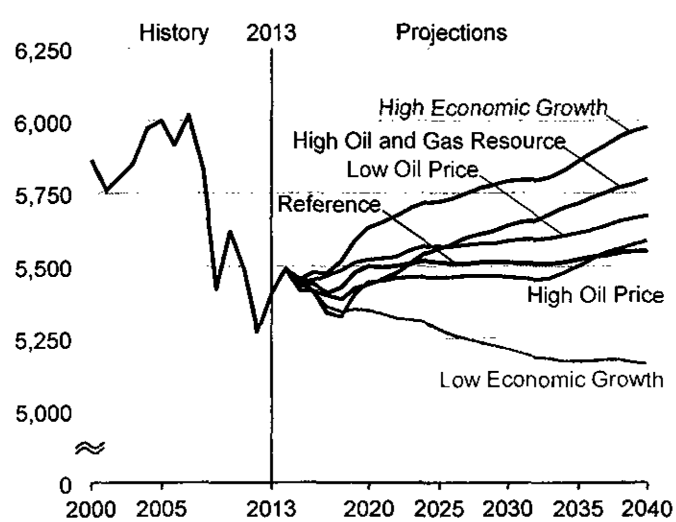
High construction costs for nuclear plants limit their competitiveness to meet new demand in the Reference case. In the near term, 5.5 GW of planned additions are put into place by 2020, offset by 3.2 GW of retirements over the same period. After 2025, 3.5 GW of additional nuclear capacity is built, based on relative economics. In the High Economic Growth and High Oil Price cases, an additional 10 GW to 13 GW of nuclear capacity above the Reference case is added by 2040 to meet demand growth, as a result of higher costs for the alternative technologies and/or higher capacity requirements.

Energy-related carbon dioxide emissions

In the AEO2015 Reference case projection, U.S. energy-related CO2 emissions are 5,549 million metric tons (mt) in 2040. Among the alternative cases, emissions totals show the greatest sensitivity to levels of economic growth (Figure 36), with 2040 totals varying from 5,979 million mt in the High Economic Growth case to 5,160 million mt in the Low Economic Growth case. In all the AEO2015 cases, emissions remain below the 2005 level of 5,993 million mt. As noted above, the AEO2015 cases do not assume implementation of EPA's proposed Clean Power Plan or other actions beyond current policies to limit or reduce CO2 emissions.

Emissions per dollar of GDP fall from the 2013 level in all the AEO2015 cases. In the Reference case, most of the decline is

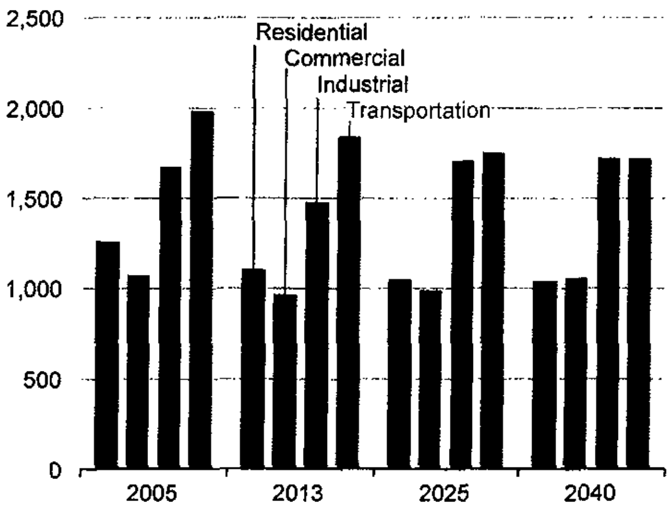
Figure 36. Energy-related carbon dioxide emissions in six cases. 2000-2040 (million metric tons)



attributable to a 2.0%/year decrease in energy intensity. In addition, the carbon intensity of the energy supply declines by 0.2%/year over the projection period.

The main factors influencing CO2 emissions include substitution of natural gas for coal in electricity generation, increases in the use of renewable energy, improvements in vehicle fuel economy, and increases in the efficiencies of appliances and industrial processes. In the Reference case, CO2 emissions growth varies across the end-use sectors (Figure 37). The highest annual growth rate (0.5%) is projected for the industrial sector, reflecting a resurgence of industrial production fueled mainly by natural gas. CO2 emissions in the commercial sector grow by 0.3%/year in the Reference case, while emissions in both the residential and transportation sectors decline on average by 0.2%/year.

Figure 37. Energy-related carbon dioxide emissions by sector in the Reference case, 2005, 2013, 2025, and 2040 (million metric tons)



In the alternative cases, various factors play roles in the emissions picture. In the High Economic Growth case, GDP increases annually by 2.9% and overshadows the decrease in energy intensity of 2.2%, leading to the largest annual rate of increase in CO2 emissions (0.4%/year). In the Low Economic Growth case, GDP grows by only 1.8%/year, and that growth is offset by a similar annual average decline in energy intensity. With the additional decline in the carbon intensity of the energy supply, CO2 emissions decline by 0.2%/year in the Low Economic Growth case.

Emissions levels also vary across the other alternative cases. The High Oil and Gas Resource case has the second-highest rate of emissions in 2040 (after the High Economic Growth case) at 5,800 million mt. In the Low Oil Price case, CO2 emissions total 5,671 million mt in 2040. In the High Oil Price case, emissions levels remain lower than projected in the Reference case throughout most of the period from 2013 to 2040, but energy-related CO2 emissions exceed the Reference case level by 35 million mt in 2040, at 5,584 million mt.

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List of acronyms

AEO	Annual Energy Outlook
AEO2015	Annual Energy Outlook 2015
API	American Petroleum Institute
bbl	Barrels
bbl/d	Barrels per day
Brent	North Sea Brent
Btu	British thermal unit(s)
CAFE	Corporate average fuel economy
CAIR	Clean Air Interstate Rule
CHP	Combined heat and power
CO2	Carbon dioxide
CPI	Consumer price index
CSAPR	Cross-State Air Pollution Rule
CTL	Coal-to-liquids
E85	Motor fuel containing up to 85% ethanol
EIA	U.S. Energy Information Administration
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EUR	Estimated ultimate recovery
GDP	Gross domestic product
GTL	Gas-to-liquids
GW	Gigawatt(s)
HDV	Heavy-duty vehicle
HGL	Hydrocarbon gas liquids
kWh	Kilowatthour(s)
LDV	Light-duty vehicle
LNG	Liquefied natural gas
MARPOL	Marine pollution
MATS	Mercury and Air Toxics Standards
Mcf	Thousand cubic feet
MELs	Miscellaneous electric loads
mpg	Miles per gallon
mt	Metric ton(s)
NGPL	Natural gas plant liquids
OECD	Organization for Economic Cooperation and Development
OPEC	Organization of the Petroleum Exporting Countries
PADD	Petroleum Administration for Defense District
PV	Photovoltaic
RFS	Renewable fuel standard
Tcf	Trillion cubic feet
U.S.	United States
VMT	Vehicle miles traveled

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Figure and table sources

Links current as of April 2015

Figure ES1. North Sea Brent crude oil spot prices in four cases, 2005-40: History: U.S. Energy Information Administration, Petroleum & Other Liquids, Europe Bent Spot Price FOB, http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RBRTE&f=D. **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, and HIGHRESOURCE.D021915B.

Figure ES2. Average Henry Hub spot prices for natural gas in four cases, 2005-40: History: U.S. Energy Information Administration, *Natural Gas Annual 2013*, DOE/EIA-0131(2013) (Washington, DC, October 2014). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, and HIGHRESOURCE.D021915B.

Figure ES3. U.S. net energy imports in six cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, LOWMACRO.D021915A, HIGHMACRO.D021915A, and HIGHRESOURCE.D021915B.

Table ES1. Growth of trade-related factors in the Reference case, 1983-2040: AEO2015 National Energy Modeling System, runs REF2015.D021915A.

Figure ES4. Net crude oil and petroleum product imports as a percentage of U.S. product supplied in four cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, and HIGHRESOURCE.D021915B.

Figure ES5. U.S. total net natural gas imports in four cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, and HIGHRESOURCE.D021915B.

Figure ES6. Change in U.S. Lower 48 onshore crude oil production by region in six cases, 2013-40: Projections: AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, LOWMACRO.D021915A, HIGHMACRO.D021915A, and HIGHRESOURCE.D021915B.

Figure ES7. Delivered energy consumption for transportation in six cases, 2008-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, LOWMACRO.D021915A, HIGHMACRO.D021915A, and HIGHRESOURCE.D021915B.

Figure ES8. Total U.S. renewable generation in all sectors by fuel in six cases, 2013 and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, LOWMACRO.D021915A, HIGHMACRO.D021915A, and HIGHRESOURCE.D021915B.

Table 1. Summary of AEO2015 cases: U.S. Energy Information Administration.

Table 2. Growth in key economic factors in historical data and in the Reference case: AEO2015 National Energy Modeling System, run REF2015.D021915A.

Figure 1. Annual changes in U.S. gross domestic product, business investment, and exports in the Reference case, 2015-40: Projections: AEO2015 National Energy Modeling System, run REF2015.D021915A.

Figure 2. Annual growth rates for industrial output in three cases, 2013-40: Projections: AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWMACRO.D021915A, and HIGHMACRO.D021915A.

Table 3. Average annual growth of labor productivity, employment, income, and consumption in three cases: Projections: AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWMACRO.D021915A, and HIGHMACRO.D021915A.

Figure 3. North Sea Brent crude oil spot prices in four cases, 2005-40: History: U.S. Energy Information Administration, Petroleum & Other Liquids, Europe Bent Spot Price FOB, http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=RBRTE&f=D. **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, and HIGHPRICE.D021915A.

Figure 4. Motor gasoline prices in three cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, and HIGHPRICE.D021915A.

Figure 5. Distillate fuel oil prices in three cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, and HIGHPRICE.D021915A.

Figure 6. Average Henry Hub spot prices for natural gas in four cases, 2005-40: History: U.S. Energy Information Administration, *Natural Gas Annual 2013*, DOE/EIA-0131(2013) (Washington, DC, October 2014). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, and HIGHRESOURCE.D021915B.

Figure 7. Average minemouth coal prices by region in the Reference case, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A.

Figure 8. Average delivered coal prices in six cases, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, LOWMACRO.D021915A, HIGHMACRO.D021915A, and HIGHRESOURCE.D021915B.

Figure 9. Average retail electricity prices in six cases, 2013-40: AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, LOWMACRO.D021915A, HIGHMACRO.D021915A, and HIGHRESOURCE.D021915B.

Figure 10. Delivered energy consumption for transportation by mode in the Reference case, 2013 and 2040: History: U.S. Energy Information Administration, Natural Gas Annual 2013, DOE/EIA-0131(2013) (Washington, DC, October 2014). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A.

Figure 11. Delivered energy consumption for transportation in six cases, 2008-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, LOWMACRO.D021915A, HIGHMACRO.D021915A, and HIGHRESOURCE.D021915B.

Figure 12. Industrial sector total delivered energy consumption in three cases, 2010-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWMACRO.D021915A, and HIGHMACRO.D021915A.

Figure 13. Industrial sector natural gas consumption for heat and power in three cases, 2010-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, HIGHPRICE.D021915A, and HIGHRESOURCE.D021915B.

Figure 14. Residential sector delivered energy consumption by fuel in the Reference case, 2010-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A.

Figure 15. Commercial sector delivered energy consumption by fuel in the Reference case, 2010-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A.

Table 4. Residential households and commercial indicators in three AEO2015 cases, 2013 and 2040: AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWMACRO.D021915A, and HIGHMACRO.D021915A.

Figure 16. Residential sector delivered energy intensity for selected end uses in the Reference case, 2013 and 2040: AEO2015 National Energy Modeling System, run REF2015.D021915A.

Figure 17. Commercial sector delivered energy intensity for selected end uses in the Reference case, 2013 and 2040: AEO2015 National Energy Modeling System, run REF2015.D021915A.

Figure 18. Primary energy consumption by fuel in the Reference case, 1980-2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A.

Figure 19. Energy use per capita and per 2009 dollar of gross domestic product, and carbon dioxide emissions per 2009 dollar of gross domestic product, in the Reference case, 1980-2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A.

Figure 20. Total energy production and consumption in the Reference case, 1980-2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A.

Figure 21. U.S. tight oil production in four cases, 2005-40: AEO2015 National Energy Modeling System, run REF2015.D021915A.

Figure 22. U.S. total crude oil production in four cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A.

Figure 23. U.S. net crude oil imports in four cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, and HIGHRESOURCE.D021915B.

Figure 24. U.S. net petroleum product imports in four cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, and HIGHRESOURCE.D021915B.

Figure 25. U.S. total dry natural gas production in four cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, and HIGHRESOURCE.D021915B.

Figure 26. U.S. shale gas production in four cases, 2005-40: AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, and HIGHRESOURCE.D021915B.

Figure 27. U.S. total natural gas net imports in four cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, and HIGHRESOURCE.D021915B.

Figure 28. U.S. liquefied natural gas net imports in four cases, 2005-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, and HIGHRESOURCE.D021915B.

Figure 29. U.S. coal production in six cases, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, LOWMACRO.D021915A, HIGHMACRO.D021915A, and HIGHRESOURCE.D021915B.

Figure 30. U.S. coal exports in six cases, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, LOWMACRO.D021915A, HIGHMACRO.D021915A, and HIGHRESOURCE.D021915B.

Figure 31. Electricity generation by fuel in the Reference case, 2000-2040: History: U.S. Energy Information Administration, Monthly Energy Review, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A.

Figure 32. Electricity generation by fuel in six cases, 2013 and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, LOWMACRO.D021915A, HIGHMACRO.D021915A, and HIGHRESOURCE.D021915B.

Figure 33. Coal and natural gas combined-cycle generation capacity factors in two cases, 2010-40: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A and HIGHRESOURCE.D021915B.

Figure 34. Renewable electricity generation by fuel type in the Reference case, 2000-2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A.

Figure 35. Cumulative additions to electricity generation capacity by fuel in six cases, 2013-40: AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, LOWMACRO.D021915A, HIGHMACRO.D021915A, and HIGHRESOURCE.D021915B.

Figure 36. Energy-related carbon dioxide emissions in six cases, 2000-2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, runs REF2015.D021915A, LOWPRICE.D021915A, HIGHPRICE.D021915A, LOWMACRO.D021915A, HIGHMACRO.D021915A, and HIGHRESOURCE.D021915B.

Figure 37. Energy-related carbon dioxide emissions by sector in the Reference cases, 2005, 2013, 2025, and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A.

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Appendix A
Reference case

Table A1. Total energy supply, disposition, and price summary
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Production								
Crude oil and lease condensate	13.7	15.6	22.2	21.5	21.1	19.8	19.9	0.9%
Natural gas plant liquids	3.3	3.6	5.5	5.7	5.7	5.6	5.5	1.7%
Dry natural gas	24.6	25.1	29.6	31.3	33.9	35.1	36.4	1.4%
Coal[1]	20.7	20.0	21.7	22.2	22.5	22.5	22.6	0.5%
Nuclear / uranium[2]	8.1	8.3	8.4	8.5	8.5	8.5	8.7	0.2%
Conventional hydroelectric power	2.6	2.5	2.8	2.8	2.8	2.8	2.8	0.4%
Biomass[3]	4.0	4.2	4.4	4.6	4.6	4.7	5.0	0.7%
Other renewable energy[4]	1.9	2.3	3.2	3.4	3.6	4.1	4.6	2.7%
Other[5]	0.8	1.3	0.9	0.9	0.9	0.9	1.0	-1.0%
Total	**79.6**	**82.7**	**98.7**	**100.9**	**103.7**	**103.9**	**106.6**	**0.9%**
Imports								
Crude oil	18.7	17.0	13.6	14.9	15.7	17.7	18.2	0.3%
Petroleum and other liquids[6]	4.2	4.3	4.6	4.5	4.4	4.3	4.1	-0.2%
Natural gas[7]	3.2	2.9	1.9	1.7	1.6	1.5	1.7	-1.9%
Other imports[8]	0.3	0.3	0.1	0.1	0.1	0.1	0.1	-5.2%
Total	**26.4**	**24.5**	**20.2**	**21.3**	**21.7**	**23.6**	**24.1**	**-0.1%**
Exports								
Petroleum and other liquids[9]	6.5	7.3	11.2	12.0	12.6	13.3	13.7	2.4%
Natural gas[10]	1.6	1.6	4.5	5.2	6.4	6.8	7.4	5.9%
Coal	3.1	2.9	2.5	2.9	3.3	3.4	3.5	0.8%
Total	**11.2**	**11.7**	**18.1**	**20.1**	**22.4**	**23.4**	**24.6**	**2.8%**
Discrepancy[11]	**0.4**	**-1.6**	**-0.1**	**0.0**	**0.2**	**0.3**	**0.3**	**- -**
Consumption								
Petroleum and other liquids[12]	35.2	35.9	37.1	36.9	36.5	36.3	36.2	0.0%
Natural gas	26.1	26.9	26.8	27.6	28.8	29.6	30.5	0.5%
Coal[13]	17.3	18.0	19.2	19.3	19.2	19.0	19.0	0.2%
Nuclear / uranium[2]	8.1	8.3	8.4	8.5	8.5	8.5	8.7	0.2%
Conventional hydroelectric power	2.6	2.5	2.8	2.8	2.8	2.8	2.8	0.4%
Biomass[14]	2.8	2.9	3.0	3.2	3.2	3.2	3.5	0.7%
Other renewable energy[4]	1.9	2.3	3.2	3.4	3.6	4.1	4.6	2.7%
Other[15]	0.4	0.4	0.3	0.3	0.3	0.3	0.3	-0.7%
Total	**94.4**	**97.1**	**100.8**	**102.0**	**102.9**	**103.8**	**105.7**	**0.3%**
Prices (2013 dollars per unit)								
Crude oil spot prices (dollars per barrel)								
Brent	113	109	79	91	106	122	141	1.0%
West Texas Intermediate	96	98	73	85	99	116	136	1.2%
Natural gas at Henry Hub (dollars per million Btu)	2.79	3.73	4.88	5.46	5.69	6.60	7.85	2.8%
Coal (dollars per ton)								
at the minemouth[16]	40.5	37.2	37.9	40.3	43.7	46.7	49.2	1.0%
Coal (dollars per million Btu)								
at the minemouth[16]	2.01	1.84	1.88	2.02	2.18	2.32	2.44	1.0%
Average end-use[17]	2.63	2.50	2.54	2.71	2.84	2.96	3.09	0.8%
Average electricity (cents per kilowatthour)	10.0	10.1	10.5	11.0	11.1	11.3	11.8	0.6%

Table A1. Total energy supply, disposition, and price summary (continued)

(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Prices (nominal dollars per unit)								
Crude oil spot prices (dollars per barrel)								
Brent	112	109	90	112	142	180	229	2.8%
West Texas Intermediate	94	98	83	105	133	171	220	3.0%
Natural gas at Henry Hub (dollars per million Btu)	2.75	3.73	5.54	6.72	7.63	9.70	12.73	4.7%
Coal (dollars per ton)								
at the minemouth[16]	40.0	37.2	43.0	49.7	58.6	68.6	79.8	2.9%
Coal (dollars per million Btu)								
at the minemouth[16]	1.98	1.84	2.14	2.48	2.92	3.41	3.96	2.9%
Average end-use[17]	2.59	2.50	2.88	3.33	3.81	4.35	5.00	2.6%
Average electricity (cents per kilowatthour)	9.8	10.1	11.9	13.5	14.8	16.6	19.2	2.4%

[1]Includes waste coal.
[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[3]*Includes grid-connected electricity from wood and wood waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood.* Refer to Table A17 for details.
[4]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy data.
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes imports of liquefied natural gas that are later re-exported.
[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.
[9]Includes crude oil, petroleum products, ethanol, and biodiesel.
[10]Includes re-exported liquefied natural gas.
[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[12]Estimated consumption. Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are hydrocarbon gas liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[13]Excludes coal converted to coal-based synthetic liquids and natural gas.
[14]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[16]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[17]*Prices weighted by consumption; weighted average excludes export free-alongside-ship (f.a.s.) prices.*
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 natural gas supply values: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2013*, DOE/EIA-0131(2013) (Washington, DC, October 2014). 2013 natural gas supply values: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). 2012 and 2013 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2013*, DOE/EIA-0584(2013) (Washington, DC, January 2015). 2013 petroleum supply values and 2012 crude oil and lease condensate production: EIA, *Petroleum Supply Annual 2013*, DOE/EIA-0340(2013)/1 (Washington, DC, September 2014). Other 2012 petroleum supply values: EIA, *Petroleum Supply Annual 2012*, *DOE/EIA-0340(2012)/1 (Washington, DC, September 2013). 2012 and 2013 crude oil spot prices* and natural gas spot price at Henry Hub: Thomson Reuters. Other 2012 and 2013 coal values: *Quarterly Coal Report, October-December 2013*, DOE/EIA-0121(2013/4Q) (Washington, DC, March 2014). Other 2012 and 2013 values: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A2. Energy consumption by sector and source
(quadrillion Btu per year, unless otherwise noted)

Sector and source	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Energy consumption								
Residential								
Propane	0.40	0.43	0.32	0.30	0.28	0.26	0.25	-2.0%
Kerosene	0.01	0.01	0.01	0.01	0.01	0.00	0.00	-3.0%
Distillate fuel oil	0.49	0.50	0.40	0.35	0.31	0.27	0.24	-2.7%
Petroleum and other liquids subtotal	0.90	0.93	0.73	0.66	0.59	0.54	0.49	-2.4%
Natural gas	4.25	5.05	4.63	4.54	4.52	4.43	4.31	-0.6%
Renewable energy[1]	0.44	0.58	0.41	0.39	0.38	0.36	0.35	-1.8%
Electricity	4.69	4.75	4.86	4.92	5.08	5.23	5.42	0.5%
Delivered energy	**10.28**	**11.32**	**10.63**	**10.51**	**10.57**	**10.56**	**10.57**	**-0.3%**
Electricity related losses	9.57	9.79	9.75	9.74	9.91	10.10	10.33	0.2%
Total	**19.85**	**21.10**	**20.38**	**20.25**	**20.48**	**20.66**	**20.91**	**0.0%**
Commercial								
Propane	0.14	0.15	0.16	0.17	0.17	0.17	0.18	0.7%
Motor gasoline[2]	0.04	0.05	0.05	0.05	0.05	0.05	0.06	0.8%
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.4%
Distillate fuel oil	0.36	0.37	0.34	0.32	0.30	0.29	0.27	-1.1%
Residual fuel oil	0.03	0.03	0.07	0.07	0.07	0.07	0.06	3.3%
Petroleum and other liquids subtotal	0.57	0.59	0.62	0.61	0.60	0.59	0.58	-0.1%
Natural gas	2.97	3.37	3.30	3.29	3.43	3.57	3.71	0.4%
Coal	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.5%
Renewable energy[3]	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.0%
Electricity	4.53	4.57	4.82	4.99	5.19	5.40	5.66	0.8%
Delivered energy	**8.22**	**8.69**	**8.90**	**9.06**	**9.38**	**9.73**	**10.12**	**0.6%**
Electricity related losses	9.24	9.42	9.68	9.88	10.13	10.43	10.80	0.5%
Total	**17.46**	**18.10**	**18.58**	**18.94**	**19.52**	**20.16**	**20.92**	**0.5%**
Industrial[4]								
Liquefied petroleum gases and other[5]	2.42	2.51	3.20	3.56	3.72	3.69	3.67	1.4%
Motor gasoline[2]	0.24	0.25	0.26	0.26	0.25	0.25	0.25	0.0%
Distillate fuel oil	1.28	1.31	1.42	1.38	1.36	1.34	1.35	0.1%
Residual fuel oil	0.07	0.06	0.10	0.14	0.13	0.13	0.13	2.9%
Petrochemical feedstocks	0.74	0.74	0.95	1.10	1.14	1.17	1.20	1.8%
Other petroleum[6]	3.33	3.52	3.67	3.80	3.83	3.89	3.99	0.5%
Petroleum and other liquids subtotal	8.08	8.40	9.61	10.24	10.44	10.47	10.59	0.9%
Natural gas	7.39	7.62	8.33	8.47	8.65	8.76	8.90	0.6%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[7]	1.43	1.52	1.87	1.98	2.10	2.18	2.29	1.5%
Natural gas subtotal	8.82	9.14	10.20	10.44	10.75	10.94	11.19	0.8%
Metallurgical coal	0.59	0.62	0.61	0.59	0.56	0.53	0.51	-0.7%
Other industrial coal	0.87	0.88	0.93	0.95	0.96	0.97	0.99	0.4%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Net coal coke imports	0.00	-0.02	0.00	-0.01	-0.03	-0.05	-0.06	4.5%
Coal subtotal	1.47	1.48	1.54	1.53	1.48	1.44	1.44	-0.1%
Biofuels heat and coproducts	0.73	0.72	0.80	0.80	0.80	0.81	0.86	0.6%
Renewable energy[8]	1.51	1.48	1.53	1.60	1.59	1.58	1.63	0.4%
Electricity	3.36	3.26	3.74	3.98	4.04	4.05	4.12	0.9%
Delivered energy	**23.97**	**24.48**	**27.42**	**28.58**	**29.10**	**29.29**	**29.82**	**0.7%**
Electricity related losses	6.87	6.72	7.51	7.88	7.88	7.83	7.85	0.6%
Total	**30.84**	**31.20**	**34.93**	**36.46**	**36.98**	**37.12**	**37.68**	**0.7%**

Table A2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Transportation								
Propane	0.05	0.05	0.04	0.05	0.05	0.06	0.07	1.3%
Motor gasoline[2]	15.82	15.94	15.35	14.22	13.30	12.82	12.55	-0.9%
of which: E85[9]	0.01	0.02	0.03	0.12	0.20	0.24	0.28	10.0%
Jet fuel[10]	2.86	2.80	3.01	3.20	3.40	3.54	3.64	1.0%
Distillate fuel oil[11]	5.80	6.50	7.35	7.59	7.76	7.94	7.97	0.8%
Residual fuel oil	0.67	0.57	0.35	0.36	0.36	0.36	0.36	-1.6%
Other petroleum[12]	0.15	0.15	0.16	0.16	0.16	0.16	0.16	0.2%
Petroleum and other liquids subtotal	25.35	26.00	26.27	25.57	25.03	24.88	24.76	-0.2%
Pipeline fuel natural gas	0.75	0.88	0.85	0.90	0.94	0.94	0.96	0.3%
Compressed / liquefied natural gas	0.04	0.05	0.07	0.10	0.17	0.31	0.71	10.3%
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electricity	0.02	0.02	0.03	0.04	0.04	0.05	0.06	3.4%
Delivered energy	**26.16**	**26.96**	**27.22**	**26.60**	**26.18**	**26.19**	**26.49**	**-0.1%**
Electricity related losses	0.05	0.05	0.06	0.07	0.08	0.10	0.12	3.1%
Total	**26.20**	**27.01**	**27.29**	**26.67**	**26.27**	**26.29**	**26.61**	**-0.1%**
Unspecified sector[13]	**0.04**	**-0.27**	**-0.34**	**-0.36**	**-0.37**	**-0.38**	**-0.38**	**- -**
Delivered energy consumption for all sectors								
Liquefied petroleum gases and other[5]	3.01	3.14	3.73	4.08	4.23	4.19	4.17	1.1%
Motor gasoline[2]	16.10	16.36	15.79	14.65	13.72	13.23	12.96	-0.9%
of which: E85[9]	0.01	0.02	0.03	0.12	0.20	0.24	0.28	10.0%
Jet fuel[10]	2.90	2.97	3.20	3.39	3.61	3.76	3.86	1.0%
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-1.0%
Distillate fuel oil	7.92	8.10	8.86	8.97	9.05	9.14	9.13	0.4%
Residual fuel oil	0.77	0.65	0.53	0.56	0.56	0.55	0.56	-0.6%
Petrochemical feedstocks	0.74	0.74	0.95	1.10	1.14	1.17	1.20	1.8%
Other petroleum[14]	3.47	3.67	3.82	3.96	3.98	4.05	4.15	0.5%
Petroleum and other liquids subtotal	34.93	35.65	36.89	36.72	36.30	36.09	36.03	0.0%
Natural gas	14.65	16.10	16.32	16.40	16.76	17.07	17.64	0.3%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[7]	1.43	1.52	1.87	1.98	2.10	2.18	2.29	1.5%
Pipeline fuel natural gas	0.75	0.88	0.85	0.90	0.94	0.94	0.96	0.3%
Natural gas subtotal	16.82	18.50	19.05	19.28	19.80	20.19	20.88	0.4%
Metallurgical coal	0.59	0.62	0.61	0.59	0.56	0.53	0.51	-0.7%
Other coal	0.91	0.92	0.98	1.00	1.00	1.01	1.04	0.4%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Net coal coke imports	0.00	-0.02	0.00	-0.01	-0.03	-0.05	-0.06	4.5%
Coal subtotal	1.51	1.52	1.59	1.58	1.53	1.49	1.49	-0.1%
Biofuels heat and coproducts	0.73	0.72	0.80	0.80	0.80	0.81	0.86	0.6%
Renewable energy[15]	2.06	2.18	2.06	2.11	2.09	2.06	2.10	-0.1%
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electricity	12.61	12.60	13.45	13.91	14.35	14.74	15.25	0.7%
Delivered energy	**68.66**	**71.17**	**73.84**	**74.39**	**74.87**	**75.39**	**76.62**	**0.3%**
Electricity related losses	25.73	25.97	27.00	27.58	28.01	28.46	29.10	0.4%
Total	**94.40**	**97.14**	**100.84**	**101.97**	**102.87**	**103.85**	**105.73**	**0.3%**
Electric power[16]								
Distillate fuel oil	0.05	0.05	0.09	0.09	0.08	0.08	0.08	1.6%
Residual fuel oil	0.17	0.21	0.08	0.09	0.09	0.09	0.09	-3.0%
Petroleum and other liquids subtotal	0.22	0.26	0.17	0.17	0.17	0.17	0.18	-1.5%
Natural gas	9.31	8.36	7.80	8.33	9.03	9.40	9.61	0.5%
Steam coal	15.82	16.49	17.59	17.75	17.63	17.54	17.52	0.2%
Nuclear / uranium[17]	8.06	8.27	8.42	8.46	8.47	8.51	8.73	0.2%
Renewable energy[18]	4.53	4.78	6.13	6.43	6.72	7.26	7.99	1.9%
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.0%
Electricity imports	0.16	0.18	0.11	0.12	0.10	0.09	0.11	-1.8%
Total	**38.34**	**38.57**	**40.45**	**41.49**	**42.35**	**43.19**	**44.36**	**0.5%**

Table A2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Total energy consumption								
Liquefied petroleum gases and other[5]	3.01	3.14	3.73	4.08	4.23	4.19	4.17	1.1%
Motor gasoline[2]	16.10	16.36	15.79	14.65	13.72	13.23	12.96	-0.9%
of which: E85[9]	0.01	0.02	0.03	0.12	0.20	0.24	0.28	10.0%
Jet fuel[10]	2.90	2.97	3.20	3.39	3.61	3.76	3.86	1.0%
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-1.0%
Distillate fuel oil	7.98	8.15	8.95	9.06	9.13	9.22	9.21	0.5%
Residual fuel oil	0.94	0.87	0.61	0.65	0.64	0.64	0.65	-1.1%
Petrochemical feedstocks	0.74	0.74	0.95	1.10	1.14	1.17	1.20	1.8%
Other petroleum[14]	3.47	3.67	3.82	3.96	3.98	4.05	4.15	0.5%
Petroleum and other liquids subtotal	35.16	35.91	37.06	36.89	36.47	36.26	36.21	0.0%
Natural gas	23.96	24.46	24.12	24.73	25.79	26.47	27.25	0.4%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[7]	1.43	1.52	1.87	1.98	2.10	2.18	2.29	1.5%
Pipeline fuel natural gas	0.75	0.88	0.85	0.90	0.94	0.94	0.96	0.3%
Natural gas subtotal	26.14	26.86	26.85	27.60	28.83	29.59	30.50	0.5%
Metallurgical coal	0.59	0.62	0.61	0.59	0.56	0.53	0.51	-0.7%
Other coal	16.73	17.41	18.57	18.75	18.63	18.55	18.56	0.2%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Net coal coke imports	0.00	-0.02	0.00	-0.01	-0.03	-0.05	-0.06	4.5%
Coal subtotal	17.33	18.01	19.18	19.33	19.16	19.03	19.01	0.2%
Nuclear / uranium[17]	8.06	8.27	8.42	8.46	8.47	8.51	8.73	0.2%
Biofuels heat and coproducts	0.73	0.72	0.80	0.80	0.80	0.81	0.86	0.6%
Renewable energy[19]	6.59	6.96	8.19	8.54	8.81	9.32	10.09	1.4%
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.0%
Electricity imports	0.16	0.18	0.11	0.12	0.10	0.09	0.11	-1.8%
Total	**94.40**	**97.14**	**100.84**	**101.97**	**102.87**	**103.85**	**105.73**	**0.3%**
Energy use and related statistics								
Delivered energy use	68.66	71.17	73.84	74.39	74.87	75.39	76.62	0.3%
Total energy use	94.40	97.14	100.84	101.97	102.87	103.85	105.73	0.3%
Ethanol consumed in motor gasoline and E85	1.09	1.12	1.12	1.12	1.12	1.16	1.27	0.5%
Population (millions)	315	317	334	347	359	370	380	0.7%
Gross domestic product (billion 2009 dollars)	15,369	15,710	18,801	21,295	23,894	26,659	29,898	2.4%
Carbon dioxide emissions (million metric tons)	5,272	5,405	5,499	5,511	5,514	5,521	5,549	0.1%

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal water heating, and electricity generation from wind and solar photovoltaic sources.
[2]Includes ethanol and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal water heating and electricity generation from wind and solar photovoltaic sources.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[5]Includes ethane, natural gasoline, and refinery olefins.
[6]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[7]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[8]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol in motor gasoline.
[9]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[10]Includes only kerosene type.
[11]Diesel fuel for on- and off- road use.
[12]Includes aviation gasoline and lubricants.
[13]Represents consumption unattributed to the sectors above.
[14]Includes aviation gasoline, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[15]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[16]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[17]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[18]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[19]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
Btu = British thermal unit.
- - = Not applicable.
Note: Includes estimated consumption for petroleum and other liquids. Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2012 and 2013 population and gross domestic product: IHS Economics, Industry and Employment models, November 2014. 2012 and 2013 carbon dioxide emissions and emission factors: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A3. Energy prices by sector and source
(2013 dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Residential								
Propane	24.3	23.3	23.0	23.7	24.4	25.5	26.6	0.5%
Distillate fuel oil	27.3	27.2	21.5	23.7	26.3	29.4	32.9	0.7%
Natural gas	10.6	10.0	11.6	12.7	12.8	13.7	15.5	1.6%
Electricity	35.3	35.6	37.8	39.6	40.0	40.8	42.4	0.6%
Commercial								
Propane	21.0	20.0	19.4	20.2	21.1	22.5	23.9	0.7%
Distillate fuel oil	26.8	26.7	21.0	23.2	25.8	28.9	32.5	0.7%
Residual fuel oil	22.9	22.1	14.2	16.0	18.1	20.6	24.3	0.4%
Natural gas	8.2	8.1	9.6	10.5	10.4	11.1	12.6	1.6%
Electricity	30.0	29.7	31.1	32.5	32.6	33.1	34.5	0.6%
Industrial[1]								
Propane	21.3	20.3	19.6	20.5	21.5	22.9	24.5	0.7%
Distillate fuel oil	27.4	27.3	21.2	23.5	26.1	29.2	32.7	0.7%
Residual fuel oil	20.6	20.0	13.3	15.1	17.2	19.7	23.5	0.6%
Natural gas[2]	3.8	4.6	6.2	6.9	6.8	7.5	8.8	2.5%
Metallurgical coal	7.3	5.5	5.8	6.2	6.7	6.9	7.2	1.0%
Other industrial coal	3.3	3.2	3.3	3.5	3.6	3.7	3.9	0.7%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	19.8	20.2	21.3	22.4	22.6	23.3	24.7	0.7%
Transportation								
Propane	25.3	24.6	24.0	24.7	25.5	26.5	27.6	0.4%
E85[3]	35.7	33.1	30.4	29.0	31.2	33.2	35.4	0.3%
Motor gasoline[4]	30.7	29.3	22.5	24.3	26.4	29.1	32.3	0.4%
Jet fuel[5]	23.0	21.8	16.1	18.3	21.3	24.5	28.3	1.0%
Diesel fuel (distillate fuel oil)[6]	28.8	28.2	23.1	25.5	28.0	31.1	34.7	0.8%
Residual fuel oil	20.0	19.3	11.7	13.3	15.4	17.6	20.3	0.2%
Natural gas[7]	20.4	17.6	17.8	16.8	15.7	17.1	19.6	0.4%
Electricity	27.8	28.5	30.2	32.3	32.9	33.9	36.0	0.9%
Electric power[8]								
Distillate fuel oil	24.1	24.0	18.8	20.9	23.6	26.7	30.2	0.9%
Residual fuel oil	20.8	18.9	11.5	13.3	15.4	17.8	21.6	0.5%
Natural gas	3.5	4.4	5.4	6.3	6.2	7.0	8.3	2.4%
Steam coal	2.4	2.3	2.4	2.5	2.7	2.8	2.9	0.8%
Average price to all users[9]								
Propane	22.9	21.9	21.1	21.8	22.6	23.8	25.2	0.5%
E85[3]	35.7	33.1	30.4	29.0	31.2	33.2	35.4	0.3%
Motor gasoline[4]	30.4	29.0	22.5	24.3	26.4	29.1	32.3	0.4%
Jet fuel[5]	23.0	21.8	16.1	18.3	21.3	24.5	28.3	1.0%
Distillate fuel oil	28.3	27.9	22.6	25.0	27.6	30.7	34.2	0.8%
Residual fuel oil	20.3	19.4	12.2	14.0	16.0	18.4	21.5	0.4%
Natural gas	5.5	6.1	7.5	8.3	8.2	9.0	10.5	2.0%
Metallurgical coal	7.3	5.5	5.8	6.2	6.7	6.9	7.2	1.0%
Other coal	2.5	2.4	2.4	2.6	2.7	2.8	3.0	0.8%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	29.3	29.5	30.8	32.1	32.4	33.2	34.7	0.6%
Non-renewable energy expenditures by sector (billion 2013 dollars)								
Residential	234	243	254	268	276	289	311	0.9%
Commercial	174	177	194	210	219	234	259	1.4%
Industrial[1]	218	224	264	302	323	349	389	2.1%
Transportation	738	719	565	596	638	706	791	0.4%
Total non-renewable expenditures	1,364	1,364	1,276	1,376	1,456	1,579	1,751	0.9%
Transportation renewable expenditures	0	1	1	4	6	8	10	10.2%
Total expenditures	**1,365**	**1,364**	**1,277**	**1,379**	**1,462**	**1,587**	**1,761**	**0.9%**

Table A3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Residential								
Propane	23.9	23.3	26.1	29.1	32.8	37.5	43.1	2.3%
Distillate fuel oil	26.9	27.2	24.4	29.1	35.3	43.2	53.3	2.5%
Natural gas	10.4	10.0	13.2	15.7	17.1	20.2	25.1	3.5%
Electricity	34.8	35.6	42.9	48.8	53.6	60.0	68.8	2.5%
Commercial								
Propane	20.7	20.0	22.0	24.9	28.3	33.0	38.8	2.5%
Distillate fuel oil	26.4	26.7	23.8	28.6	34.6	42.5	52.6	2.5%
Residual fuel oil	22.6	22.1	16.1	19.7	24.3	30.3	39.4	2.2%
Natural gas	8.0	8.1	10.8	13.0	13.9	16.4	20.5	3.5%
Electricity	29.6	29.7	35.3	40.0	43.7	48.7	56.0	2.4%
Industrial[1]								
Propane	21.0	20.3	22.3	25.2	28.8	33.7	39.7	2.5%
Distillate fuel oil	27.0	27.3	24.1	29.0	35.0	42.9	53.0	2.5%
Residual fuel oil	20.3	20.0	15.1	18.6	23.1	29.0	38.0	2.4%
Natural gas[2]	3.8	4.6	7.0	8.5	9.1	11.1	14.2	4.3%
Metallurgical coal	7.2	5.5	6.6	7.7	8.9	10.2	11.6	2.8%
Other industrial coal	3.3	3.2	3.8	4.3	4.8	5.5	6.3	2.5%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	19.5	20.2	24.2	27.5	30.3	34.2	40.0	2.6%
Transportation								
Propane	24.9	24.6	27.2	30.4	34.1	38.9	44.8	2.2%
E85[3]	35.2	33.1	34.4	35.8	41.9	48.8	57.4	2.1%
Motor gasoline[4]	30.2	29.3	25.5	29.9	35.3	42.8	52.4	2.2%
Jet fuel[5]	22.6	21.8	18.3	22.6	28.6	36.0	45.8	2.8%
Diesel fuel (distillate fuel oil)[6]	28.4	28.2	26.2	31.4	37.6	45.7	56.2	2.6%
Residual fuel oil	19.7	19.3	13.2	16.4	20.6	25.9	32.9	2.0%
Natural gas[7]	20.1	17.6	20.2	20.6	21.0	25.2	31.8	2.2%
Electricity	27.4	28.5	34.3	39.8	44.1	49.9	58.4	2.7%
Electric power[8]								
Distillate fuel oil	23.8	24.0	21.3	25.8	31.7	39.3	49.0	2.7%
Residual fuel oil	20.5	18.9	13.0	16.3	20.6	26.2	35.0	2.3%
Natural gas	3.5	4.4	6.1	7.7	8.3	10.3	13.4	4.2%
Steam coal	2.4	2.3	2.7	3.1	3.6	4.1	4.7	2.6%

Table A3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Average price to all users[9]								
Propane	22.6	21.9	23.9	26.8	30.3	35.0	40.9	2.3%
E85[3]	35.2	33.1	34.4	35.8	41.9	48.8	57.4	2.1%
Motor gasoline[4]	30.0	29.0	25.5	29.9	35.3	42.8	52.4	2.2%
Jet fuel[5]	*22.6*	*21.8*	*18.3*	*22.6*	*28.6*	*36.0*	*45.8*	*2.8%*
Distillate fuel oil	27.9	27.9	25.7	30.8	36.9	45.1	55.5	2.6%
Residual fuel oil	20.0	19.4	13.8	17.2	21.5	27.0	34.8	2.2%
Natural gas	5.4	6.1	8.5	10.2	11.0	13.2	17.0	3.8%
Metallurgical coal	7.2	5.5	6.6	7.7	8.9	10.2	11.6	2.8%
Other coal	2.4	2.4	2.8	3.2	3.7	4.2	4.8	2.6%
Coal to liquids	--	--	--	--	--	--	--	--
Electricity	28.8	29.5	34.9	39.5	43.4	48.7	56.2	2.4%
Non-renewable energy expenditures by sector (billion nominal dollars)								
Residential	231	243	288	330	370	425	504	2.7%
Commercial	172	177	220	259	294	344	420	3.2%
Industrial[1]	215	224	299	372	433	513	631	3.9%
Transportation	*727*	*719*	*641*	*734*	*855*	*1,038*	*1,283*	*2.2%*
Total non-renewable expenditures	1,344	1,364	1,448	1,694	1,952	2,320	2,839	2.8%
Transportation renewable expenditures	0	1	1	4	8	12	16	12.2%
Total expenditures	**1,345**	**1,364**	**1,449**	**1,698**	**1,960**	**2,332**	**2,855**	**2.8%**

[1]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Excludes use for lease and plant fuel.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
[5]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Natural gas used as fuel in motor vehicles, trains, and ships. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[8]Includes electricity-only and combined heat and power plants that have a regulatory status.
[9]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
-- = Not applicable.
Note: Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2014/08) (Washington, DC, August 2014). 2012 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Annual 2013*, DOE/EIA-0131(2013) (Washington, DC, October 2014). 2013 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). 2012 transportation sector natural gas delivered prices are based on: EIA, *Natural Gas Annual 2013*, DOE/EIA-0131(2013) (Washington, DC, October 2014). EIA, *State Energy Data Report 2012*, DOE/EIA-0214(2012) (Washington, DC, June 2014) and estimated State and Federal motor fuel taxes and dispensing costs or charges. 2013 transportation sector natural gas delivered prices are model results. 2012 and 2013 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2012 and 2013 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2013 and April 2014, Table 4.2, and EIA, *State Energy Data Report 2012*, DOE/EIA-0214(2012) (Washington, DC, June 2014). 2012 and 2013 coal prices based on: EIA, *Quarterly Coal Report, October-December 2013*, DOE/EIA-0121(2013/4Q) (Washington, DC, March 2014) and EIA, AEO2015 National Energy Modeling System run REF2015.D021915A. 2012 and 2013 electricity prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2012 and 2013 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A4. Residential sector key indicators and consumption
(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case 2012	2013	2020	2025	2030	2035	2040	Annual growth 2013-2040 (percent)
Key indicators								
Households (millions)								
Single-family	79.3	79.7	84.5	88.4	92.1	95.4	98.6	0.8%
Multifamily	28.2	28.4	30.4	32.1	33.9	35.7	37.5	1.0%
Mobile homes	6.4	6.3	5.5	5.3	5.1	4.9	4.8	-1.0%
Total	**113.9**	**114.3**	**120.5**	**125.8**	**131.1**	**136.0**	**141.0**	**0.8%**
Average house square footage	**1,670**	**1,678**	**1,733**	**1,768**	**1,800**	**1,829**	**1,855**	**0.4%**
Energy intensity								
(million Btu per household)								
Delivered energy consumption	90.2	99.0	88.2	83.5	80.6	77.6	75.0	-1.0%
Total energy consumption	174.3	184.6	169.1	161.0	156.2	151.9	148.3	-0.8%
(thousand Btu per square foot)								
Delivered energy consumption	54.0	59.0	50.9	47.3	44.8	42.5	40.4	-1.4%
Total energy consumption	104.3	110.0	97.6	91.1	86.8	83.1	79.9	-1.2%
Delivered energy consumption by fuel								
Purchased electricity								
Space heating	0.29	0.40	0.35	0.34	0.33	0.32	0.31	-1.0%
Space cooling	0.83	0.66	0.79	0.82	0.88	0.94	1.00	1.5%
Water heating	0.44	0.44	0.46	0.47	0.48	0.48	0.48	0.2%
Refrigeration	0.37	0.36	0.34	0.33	0.33	0.35	0.36	0.0%
Cooking	0.11	0.11	0.11	0.12	0.13	0.14	0.14	1.1%
Clothes dryers	0.20	0.20	0.21	0.22	0.23	0.24	0.25	0.7%
Freezers	0.08	0.08	0.07	0.07	0.07	0.06	0.06	-0.7%
Lighting	0.64	0.59	0.43	0.38	0.34	0.29	0.27	-2.9%
Clothes washers[1]	0.03	0.03	0.02	0.02	0.02	0.02	0.02	-2.0%
Dishwashers[1]	0.10	0.09	0.10	0.10	0.11	0.12	0.12	1.0%
Televisions and related equipment[2]	0.33	0.33	0.32	0.32	0.34	0.36	0.37	0.5%
Computers and related equipment[3]	0.12	0.12	0.10	0.08	0.07	0.06	0.05	-3.1%
Furnace fans and boiler circulation pumps	0.09	0.13	0.11	0.11	0.10	0.10	0.09	-1.3%
Other uses[4]	1.06	1.19	1.44	1.53	1.65	1.77	1.89	1.7%
Delivered energy	**4.69**	**4.75**	**4.86**	**4.92**	**5.08**	**5.23**	**5.42**	**0.5%**
Natural gas								
Space heating	2.52	3.32	2.90	2.80	2.76	2.69	2.61	-0.9%
Space cooling	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.2%
Water heating	1.20	1.20	1.21	1.22	1.24	1.23	1.19	0.0%
Cooking	0.21	0.21	0.21	0.21	0.22	0.22	0.22	0.3%
Clothes dryers	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.5%
Other uses[5]	0.25	0.25	0.24	0.23	0.23	0.22	0.21	-0.6%
Delivered energy	**4.25**	**5.05**	**4.63**	**4.54**	**4.52**	**4.43**	**4.31**	**-0.6%**
Distillate fuel oil								
Space heating	0.43	0.44	0.36	0.32	0.28	0.25	0.22	-2.5%
Water heating	0.05	0.05	0.03	0.03	0.02	0.02	0.01	-4.7%
Other uses[6]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-0.5%
Delivered energy	**0.49**	**0.50**	**0.40**	**0.35**	**0.31**	**0.27**	**0.24**	**-2.7%**
Propane								
Space heating	0.26	0.30	0.20	0.18	0.17	0.15	0.14	-2.8%
Water heating	0.07	0.06	0.05	0.04	0.04	0.03	0.03	-3.0%
Cooking	0.03	0.03	0.03	0.03	0.02	0.02	0.02	-0.9%
Other uses[6]	0.04	0.04	0.05	0.05	0.05	0.06	0.06	1.5%
Delivered energy	**0.40**	**0.43**	**0.32**	**0.30**	**0.28**	**0.26**	**0.25**	**-2.0%**
Marketed renewables (wood)[7]	0.44	0.58	0.41	0.39	0.38	0.36	0.35	-1.8%
Kerosene	0.01	0.01	0.01	0.01	0.01	0.00	0.00	-3.0%

Table A4. Residential sector key indicators and consumption (continued)
(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Delivered energy consumption by end use								
Space heating	3.95	5.05	4.23	4.04	3.92	3.78	3.63	-1.2%
Space cooling	0.86	0.68	0.81	0.84	0.90	0.96	1.02	1.5%
Water heating	1.76	1.76	1.75	1.76	1.78	1.75	1.71	-0.1%
Refrigeration	0.37	0.36	0.34	0.33	0.33	0.35	0.36	0.0%
Cooking	0.35	0.34	0.35	0.36	0.37	0.38	0.39	0.4%
Clothes dryers	0.25	0.25	0.26	0.27	0.28	0.29	0.30	0.7%
Freezers	0.08	0.08	0.07	0.07	0.07	0.06	0.06	-0.7%
Lighting	0.64	0.59	0.43	0.38	0.34	0.29	0.27	-2.9%
Clothes washers[1]	0.03	0.03	0.02	0.02	0.02	0.02	0.02	-2.0%
Dishwashers[1]	0.10	0.09	0.10	0.10	0.11	0.12	0.12	1.0%
Televisions and related equipment[2]	0.33	0.33	0.32	0.32	0.34	0.36	0.37	0.5%
Computers and related equipment[3]	0.12	0.12	0.10	0.08	0.07	0.06	0.05	-3.1%
Furnace fans and boiler circulation pumps	0.09	0.13	0.11	0.11	0.10	0.10	0.09	-1.3%
Other uses[8]	1.36	1.49	1.73	1.82	1.94	2.05	2.17	1.4%
Delivered energy	**10.28**	**11.32**	**10.63**	**10.51**	**10.57**	**10.56**	**10.57**	**-0.3%**
Electricity related losses	**9.57**	**9.79**	**9.75**	**9.74**	**9.91**	**10.10**	**10.33**	**0.2%**
Total energy consumption by end use								
Space heating	4.53	5.88	4.93	4.71	4.56	4.39	4.21	-1.2%
Space cooling	2.56	2.05	2.38	2.47	2.62	2.79	2.93	1.3%
Water heating	2.66	2.68	2.69	2.70	2.72	2.68	2.62	-0.1%
Refrigeration	1.12	1.12	1.02	0.99	0.99	1.01	1.06	-0.2%
Cooking	0.56	0.56	0.58	0.60	0.62	0.64	0.66	0.6%
Clothes dryers	0.66	0.67	0.69	0.70	0.73	0.75	0.78	0.5%
Freezers	0.24	0.24	0.22	0.20	0.19	0.19	0.19	-0.9%
Lighting	1.94	1.80	1.29	1.13	1.00	0.85	0.77	-3.1%
Clothes washers[1]	0.09	0.09	0.07	0.05	0.05	0.05	0.05	-2.2%
Dishwashers[1]	0.29	0.29	0.29	0.30	0.32	0.34	0.36	0.8%
Televisions and related equipment[2]	1.01	1.01	0.97	0.96	1.00	1.05	1.09	0.3%
Computers and related equipment[3]	0.38	0.37	0.29	0.24	0.20	0.18	0.15	-3.3%
Furnace fans and boiler circulation pumps	0.28	0.40	0.34	0.33	0.31	0.28	0.27	-1.5%
Other uses[8]	3.52	3.95	4.62	4.86	5.17	5.46	5.78	1.4%
Total	**19.85**	**21.10**	**20.38**	**20.25**	**20.48**	**20.66**	**20.91**	**0.0%**
Nonmarketed renewables[9]								
Geothermal heat pumps	0.01	0.01	0.02	0.02	0.03	0.03	0.03	4.1%
Solar hot water heating	0.01	0.01	0.01	0.01	0.01	0.01	0.01	1.8%
Solar photovoltaic	0.02	0.04	0.09	0.13	0.18	0.24	0.29	8.0%
Wind	0.00	0.00	0.01	0.01	0.01	0.01	0.01	6.9%
Total	**0.04**	**0.06**	**0.13**	**0.17**	**0.23**	**0.28**	**0.35**	**7.0%**
Heating degree days[10]	**3,772**	**4,469**	**4,119**	**4,042**	**3,966**	**3,893**	**3,820**	**-0.6%**
Cooling degree days[10]	**1,494**	**1,307**	**1,467**	**1,517**	**1,568**	**1,618**	**1,670**	**0.9%**

[1]Does not include water heating portion of load.
[2]Includes televisions, set-top boxes, home theater systems, DVD players, and video game consoles.
[3]Includes desktop and laptop computers, monitors, and networking equipment.
[4]Includes small electric devices, heating elements, and motors not listed above. Electric vehicles are included in the transportation sector.
[5]Includes such appliances as outdoor grills, exterior lights, pool heaters, spa heaters, and backup electricity generators.
[6]Includes such appliances as pool heaters, spa heaters, and backup electricity generators.
[7]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 2009*.
[8]Includes small electric devices, heating elements, outdoor grills, exterior lights, pool heaters, spa heaters, backup electricity generators, and motors not listed above. Electric vehicles are included in the transportation sector.
[9]Consumption determined by using the fossil fuel equivalent of 9,516 Btu per kilowatthour.
[10]See Table A5 for regional detail.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2012 and 2013 degree days based on state-level data from the National Oceanic and Atmospheric Administration's Climatic Data Center and Climate Prediction Center. **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A5. Commercial sector key indicators and consumption
(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Key indicators								
Total floorspace (billion square feet)								
Surviving	80.8	81.4	86.9	92.0	96.4	100.9	106.6	1.0%
New additions	1.6	1.5	2.1	2.0	2.0	2.3	2.4	1.9%
Total	**82.3**	**82.8**	**89.0**	**94.1**	**98.4**	**103.2**	**109.1**	**1.0%**
Energy consumption intensity (thousand Btu per square foot)								
Delivered energy consumption	99.8	104.9	100.0	96.3	95.4	94.2	92.8	-0.5%
Electricity related losses	112.3	113.7	108.7	105.1	103.0	101.1	99.0	-0.5%
Total energy consumption	212.1	218.6	208.7	201.4	198.4	195.3	191.8	-0.5%
Delivered energy consumption by fuel								
Purchased electricity								
Space heating[1]	0.14	0.16	0.14	0.13	0.12	0.11	0.11	-1.5%
Space cooling[1]	0.57	0.49	0.53	0.53	0.54	0.55	0.56	0.5%
Water heating[1]	0.09	0.09	0.09	0.09	0.08	0.08	0.08	-0.6%
Ventilation	0.51	0.52	0.54	0.55	0.56	0.57	0.58	0.4%
Cooking	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.3%
Lighting	0.92	0.91	0.87	0.85	0.84	0.81	0.80	-0.5%
Refrigeration	0.38	0.37	0.33	0.31	0.30	0.31	0.31	-0.7%
Office equipment (PC)	0.12	0.11	0.07	0.05	0.04	0.03	0.02	-5.5%
Office equipment (non-PC)	0.22	0.22	0.24	0.27	0.31	0.34	0.38	2.1%
Other uses[2]	1.56	1.68	1.99	2.19	2.38	2.58	2.80	1.9%
Delivered energy	**4.53**	**4.57**	**4.82**	**4.99**	**5.19**	**5.40**	**5.66**	**0.8%**
Natural gas								
Space heating[1]	1.51	1.86	1.69	1.62	1.58	1.51	1.41	-1.0%
Space cooling[1]	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.1%
Water heating[1]	0.53	0.54	0.54	0.55	0.57	0.57	0.57	0.2%
Cooking	0.20	0.20	0.21	0.22	0.23	0.24	0.25	0.8%
Other uses[3]	0.69	0.74	0.81	0.87	1.01	1.21	1.44	2.5%
Delivered energy	**2.97**	**3.37**	**3.30**	**3.29**	**3.43**	**3.57**	**3.71**	**0.4%**
Distillate fuel oil								
Space heating[1]	0.13	0.15	0.14	0.13	0.12	0.11	0.10	-1.7%
Water heating[1]	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.1%
Other uses[4]	0.21	0.20	0.18	0.17	0.17	0.16	0.16	-0.8%
Delivered energy	**0.36**	**0.37**	**0.34**	**0.32**	**0.30**	**0.29**	**0.27**	**-1.1%**
Marketed renewables (biomass)	0.11	0.12	0.12	0.12	0.12	0.12	0.12	0.0%
Other fuels[5]	0.26	0.26	0.33	0.34	0.34	0.35	0.35	1.1%
Delivered energy consumption by end use								
Space heating[1]	1.78	2.17	1.97	1.87	1.82	1.73	1.61	-1.1%
Space cooling[1]	0.62	0.53	0.57	0.57	0.57	0.58	0.59	0.4%
Water heating[1]	0.64	0.65	0.65	0.65	0.67	0.67	0.67	0.1%
Ventilation	0.51	0.52	0.54	0.55	0.56	0.57	0.58	0.4%
Cooking	0.22	0.22	0.24	0.24	0.25	0.26	0.27	0.7%
Lighting	0.92	0.91	0.87	0.85	0.84	0.81	0.80	-0.5%
Refrigeration	0.38	0.37	0.33	0.31	0.30	0.31	0.31	-0.7%
Office equipment (PC)	0.12	0.11	0.07	0.05	0.04	0.03	0.02	-5.5%
Office equipment (non-PC)	0.22	0.22	0.24	0.27	0.31	0.34	0.38	2.1%
Other uses[6]	2.82	3.00	3.43	3.69	4.02	4.42	4.87	1.8%
Delivered energy	**8.22**	**8.69**	**8.90**	**9.06**	**9.38**	**9.73**	**10.12**	**0.6%**

Table A5. Commercial sector key indicators and consumption (continued)
(quadrillion Btu per year, unless otherwise noted)

Key indicators and consumption	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Electricity related losses	**9.24**	**9.42**	**9.68**	**9.88**	**10.13**	**10.43**	**10.80**	**0.5%**
Total energy consumption by end use								
Space heating[1]	2.05	2.50	2.25	2.13	2.05	1.95	1.82	-1.2%
Space cooling[1]	1.78	1.54	1.63	1.62	1.62	1.64	1.66	0.3%
Water heating[1]	0.83	0.84	0.83	0.82	0.83	0.83	0.82	-0.1%
Ventilation	1.55	1.58	1.63	1.64	1.66	1.67	1.68	0.2%
Cooking	0.27	0.27	0.28	0.28	0.30	0.31	0.31	0.5%
Lighting	2.81	2.78	2.62	2.53	2.47	2.38	2.34	-0.6%
Refrigeration	1.15	1.14	0.99	0.93	0.90	0.90	0.91	-0.8%
Office equipment (PC)	0.35	0.33	0.20	0.15	0.11	0.09	0.07	-5.7%
Office equipment (non-PC)	0.66	0.66	0.72	0.81	0.91	1.01	1.10	1.9%
Other uses[6]	*6.01*	*6.47*	*7.43*	*8.02*	*8.67*	*9.40*	*10.21*	1.7%
Total	**17.46**	**18.10**	**18.58**	**18.94**	**19.52**	**20.16**	**20.92**	**0.5%**
Nonmarketed renewable fuels[7]								
Solar thermal	0.08	0.08	0.09	0.09	0.10	0.10	0.11	1.1%
Solar photovoltaic	0.04	0.05	0.08	0.11	0.15	0.20	0.27	6.1%
Wind	0.00	0.00	0.00	0.00	0.00	0.01	0.01	9.0%
Total	**0.13**	**0.14**	**0.17**	**0.20**	**0.25**	**0.32**	**0.39**	**3.9%**
Heating degree days								
New England	5,561	6,424	6,030	5,924	5,818	5,711	5,603	-0.5%
Middle Atlantic	4,970	5,836	5,427	5,333	5,239	5,146	5,054	-0.5%
East North Central	5,356	6,622	6,016	5,953	5,890	5,827	5,764	-0.5%
West North Central	5,515	7,134	6,367	6,322	6,275	6,229	6,181	-0.5%
South Atlantic	2,307	2,732	2,595	2,552	2,508	2,466	2,425	-0.4%
East South Central	2,876	3,649	3,349	3,325	3,301	3,276	3,251	-0.4%
West South Central	1,650	2,328	1,975	1,928	1,882	1,836	1,790	-1.0%
Mountain	4,574	5,271	4,874	4,809	4,741	4,669	4,595	-0.5%
Pacific	3,412	3,377	3,477	3,463	3,450	3,438	3,426	0.1%
United States	**3,772**	**4,469**	**4,119**	**4,042**	**3,966**	**3,893**	**3,820**	**-0.6%**
Cooling degree days								
New England	564	541	573	603	634	664	695	0.9%
Middle Atlantic	815	688	803	840	877	913	950	1.2%
East North Central	974	690	821	841	860	880	900	1.0%
West North Central	1,221	893	1,012	1,031	1,051	1,070	1,090	0.7%
South Atlantic	2,161	2,002	2,191	2,235	2,280	2,325	2,369	0.6%
East South Central	1,762	1,441	1,725	1,756	1,787	1,818	1,849	0.9%
West South Central	2,915	2,535	2,848	2,920	2,993	3,065	3,138	0.8%
Mountain	1,572	1,464	1,556	1,607	1,660	1,715	1,772	0.7%
Pacific	917	889	891	915	940	963	987	0.4%
United States	**1,494**	**1,307**	**1,467**	**1,517**	**1,568**	**1,618**	**1,670**	**0.9%**

[1]Includes fuel consumption for district services.
[2]Includes (but is not limited to) miscellaneous uses such as transformers, medical imaging and other medical equipment, elevators, escalators, off-road electric vehicles, laboratory fume hoods, laundry equipment, coffee brewers, and water services.
[3]Includes miscellaneous uses, such as pumps, emergency generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, emergency generators, and combined heat and power in commercial buildings.
[5]Includes residual fuel oil, propane, coal, motor gasoline, and kerosene.
[6]Includes (but is not limited to) miscellaneous uses such as transformers, medical imaging and other medical equipment, elevators, escalators, off-road electric vehicles, laboratory fume hoods, laundry equipment, coffee brewers, water services, pumps, emergency generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, propane, coal, motor gasoline, kerosene, and marketed renewable fuels (biomass).
[7]Consumption determined by using the fossil fuel equivalent of 9,516 Btu per kilowatthour.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2012 and 2013 degree days based on state-level data from the National Oceanic and Atmospheric Administration's Climatic Data Center and Climate Prediction Center. **Projections:** EIA, AEO2015 National Energy Modeling System run *REF2015.D021915A*.

Table A6. Industrial sector key indicators and consumption

Shipments, prices, and consumption	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Key indicators								
Value of shipments (billion 2009 dollars)								
Manufacturing	5,009	5,146	6,123	6,771	7,330	8,012	8,751	2.0%
Agriculture, mining, and construction	1,813	1,858	2,344	2,441	2,540	2,601	2,712	1.4%
Total	**6,822**	**7,004**	**8,467**	**9,212**	**9,870**	**10,614**	**11,463**	**1.8%**
Energy prices								
(2013 dollars per million Btu)								
Propane	21.3	20.3	19.6	20.5	21.5	22.9	24.5	0.7%
Motor gasoline	17.5	17.5	22.5	24.2	26.3	29.1	32.3	2.3%
Distillate fuel oil	27.4	27.3	21.2	23.5	26.1	29.2	32.7	0.7%
Residual fuel oil	20.6	20.0	13.3	15.1	17.2	19.7	23.5	0.6%
Asphalt and road oil	10.1	9.8	8.9	10.3	11.9	13.5	15.7	1.8%
Natural gas heat and power	3.5	4.3	6.0	6.7	6.6	7.4	8.6	2.6%
Natural gas feedstocks	4.2	4.8	6.3	7.0	6.9	7.7	8.9	2.3%
Metallurgical coal	7.3	5.5	5.8	6.2	6.7	6.9	7.2	1.0%
Other industrial coal	3.3	3.2	3.3	3.5	3.6	3.7	3.9	0.7%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	19.8	20.2	21.3	22.4	22.6	23.3	24.7	0.7%
(nominal dollars per million Btu)								
Propane	21.0	20.3	22.3	25.2	28.8	33.7	39.7	2.5%
Motor gasoline	17.3	17.5	25.5	29.9	35.3	42.7	52.3	4.1%
Distillate fuel oil	27.0	27.3	24.1	29.0	35.0	42.9	53.0	2.5%
Residual fuel oil	20.3	20.0	15.1	18.6	23.1	29.0	38.0	2.4%
Asphalt and road oil	10.0	9.8	10.0	12.7	15.9	19.9	25.5	3.6%
Natural gas heat and power	3.5	4.3	6.8	8.2	8.9	10.8	13.9	4.4%
Natural gas feedstocks	4.1	4.8	7.2	8.6	9.3	11.3	14.5	4.2%
Metallurgical coal	7.2	5.5	6.6	7.7	8.9	10.2	11.6	2.8%
Other industrial coal	3.3	3.2	3.8	4.3	4.8	5.5	6.3	2.5%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	19.5	20.2	24.2	27.5	30.3	34.2	40.0	2.6%
Energy consumption (quadrillion Btu)[1]								
Industrial consumption excluding refining								
Propane heat and power	0.25	0.28	0.32	0.36	0.38	0.38	0.38	1.1%
Liquefied petroleum gas and other feedstocks[2]	2.16	2.22	2.89	3.21	3.35	3.31	3.30	1.5%
Motor gasoline	0.24	0.25	0.26	0.26	0.25	0.25	0.25	0.0%
Distillate fuel oil	1.28	1.31	1.42	1.38	1.36	1.34	1.35	0.1%
Residual fuel oil	0.07	0.06	0.10	0.14	0.13	0.13	0.13	3.1%
Petrochemical feedstocks	0.74	0.74	0.95	1.10	1.14	1.17	1.20	1.8%
Petroleum coke	0.17	0.11	0.20	0.23	0.22	0.21	0.22	2.5%
Asphalt and road oil	0.83	0.78	1.01	1.09	1.15	1.19	1.25	1.8%
Miscellaneous petroleum[3]	0.37	0.61	0.42	0.42	0.44	0.46	0.47	-1.0%
Petroleum and other liquids subtotal	6.11	6.37	7.57	8.18	8.42	8.43	8.55	1.1%
Natural gas heat and power	5.26	5.42	5.86	5.93	6.07	6.13	6.20	0.5%
Natural gas feedstocks	0.58	0.59	0.97	1.05	1.05	1.04	1.03	2.1%
Lease and plant fuel[4]	1.43	1.52	1.87	1.98	2.10	2.18	2.29	1.5%
Natural gas subtotal	7.27	7.54	8.70	8.96	9.22	9.35	9.53	0.9%
Metallurgical coal and coke[5]	0.60	0.60	0.61	0.58	0.53	0.48	0.45	-1.0%
Other industrial coal	0.87	0.88	0.93	0.95	0.96	0.97	0.99	0.4%
Coal subtotal	1.47	1.48	1.54	1.53	1.48	1.44	1.44	-0.1%
Renewables[6]	1.51	1.48	1.53	1.60	1.59	1.58	1.63	0.4%
Purchased electricity	3.16	3.05	3.58	3.83	3.89	3.90	3.95	1.0%
Delivered energy	**19.52**	**19.92**	**22.92**	**24.10**	**24.60**	**24.70**	**25.10**	**0.9%**
Electricity related losses	6.46	6.29	7.19	7.59	7.59	7.52	7.54	0.7%
Total	**25.98**	**26.22**	**30.11**	**31.69**	**32.19**	**32.22**	**32.64**	**0.8%**

Table A6. Industrial sector key indicators and consumption (continued)

Shipments, prices, and consumption	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Refining consumption								
Liquefied petroleum gas heat and power[2]	0.01	0.00	0.00	0.00	0.00	0.00	0.00	- -
Distillate fuel oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Residual fuel oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Petroleum coke	0.54	0.53	0.39	0.42	0.41	0.42	0.43	-0.8%
Still gas	1.41	1.47	1.61	1.63	1.59	1.61	1.60	0.3%
Miscellaneous petroleum[3]	0.01	0.01	0.03	0.01	0.02	0.01	0.02	2.1%
Petroleum and other liquids subtotal	1.97	2.03	2.04	2.06	2.02	2.03	2.04	0.0%
Natural gas heat and power	1.23	1.30	1.19	1.17	1.20	1.25	1.31	0.0%
Natural gas feedstocks	0.32	0.31	0.31	0.31	0.32	0.34	0.35	0.5%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural gas subtotal	1.55	1.60	1.50	1.48	1.52	1.59	1.66	0.1%
Other industrial coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Coal subtotal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Biofuels heat and coproducts	0.73	0.72	0.80	0.80	0.80	0.81	0.86	0.6%
Purchased electricity	0.20	0.21	0.16	0.15	0.15	0.16	0.16	-0.8%
Delivered energy	**4.45**	**4.56**	**4.50**	**4.48**	**4.49**	**4.59**	**4.73**	**0.1%**
Electricity related losses	0.41	0.42	0.31	0.29	0.29	0.30	0.31	-1.1%
Total	**4.86**	**4.98**	**4.81**	**4.78**	**4.78**	**4.90**	**5.04**	**0.0%**
Total industrial sector consumption								
Liquefied petroleum gas heat and power[2]	0.26	0.29	0.32	0.36	0.38	0.38	0.38	1.0%
Liquefied petroleum gas and other feedstocks[2]	2.16	2.22	2.89	3.21	3.35	3.31	3.30	1.5%
Motor gasoline	0.24	0.25	0.26	0.26	0.25	0.25	0.25	0.0%
Distillate fuel oil	1.28	1.31	1.42	1.38	1.36	1.34	1.35	0.1%
Residual fuel oil	0.07	0.06	0.10	0.14	0.13	0.13	0.13	2.9%
Petrochemical feedstocks	0.74	0.74	0.95	1.10	1.14	1.17	1.20	1.8%
Petroleum coke	0.70	0.65	0.59	0.65	0.63	0.63	0.65	0.0%
Asphalt and road oil	0.83	0.78	1.01	1.09	1.15	1.19	1.25	1.8%
Still gas	1.41	1.47	1.61	1.63	1.59	1.61	1.60	0.3%
Miscellaneous petroleum[3]	0.38	0.63	0.46	0.43	0.46	0.47	0.49	-0.9%
Petroleum and other liquids subtotal	8.08	8.40	9.61	10.24	10.44	10.47	10.59	0.9%
Natural gas heat and power	6.50	6.72	7.05	7.11	7.27	7.38	7.51	0.4%
Natural gas feedstocks	0.89	0.90	1.28	1.36	1.37	1.38	1.39	1.6%
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and plant fuel[4]	1.43	1.52	1.87	1.98	2.10	2.18	2.29	1.5%
Natural gas subtotal	8.82	9.14	10.20	10.44	10.75	10.94	11.19	0.8%
Metallurgical coal and coke[5]	0.60	0.60	0.61	0.58	0.53	0.48	0.45	-1.0%
Other industrial coal	0.87	0.88	0.93	0.95	0.96	0.97	0.99	0.4%
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Coal subtotal	1.47	1.48	1.54	1.53	1.48	1.44	1.44	-0.1%
Biofuels heat and coproducts	0.73	0.72	0.80	0.80	0.80	0.81	0.86	0.6%
Renewables[6]	1.51	1.48	1.53	1.60	1.59	1.58	1.63	0.4%
Purchased electricity	3.36	3.26	3.74	3.98	4.04	4.05	4.12	0.9%
Delivered energy	**23.97**	**24.48**	**27.42**	**28.58**	**29.10**	**29.29**	**29.82**	**0.7%**
Electricity related losses	6.87	6.72	7.51	7.88	7.88	7.83	7.85	0.6%
Total	**30.84**	**31.20**	**34.93**	**36.46**	**36.98**	**37.12**	**37.68**	**0.7%**

Table A6. Industrial sector key indicators and consumption (continued)

Key indicators and consumption	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Energy consumption per dollar of shipments (thousand Btu per 2009 dollar)								
Petroleum and other liquids	1.18	1.20	1.13	1.11	1.06	0.99	0.92	-1.0%
Natural gas	1.29	1.31	1.21	1.13	1.09	1.03	0.98	-1.1%
Coal	0.21	0.21	0.18	0.17	0.15	0.14	0.13	-1.9%
Renewable fuels[6]	0.33	0.31	0.28	0.26	0.24	0.23	0.22	-1.4%
Purchased electricity	0.49	0.47	0.44	0.43	0.41	0.38	0.36	-1.0%
Delivered energy	**3.51**	**3.50**	**3.24**	**3.10**	**2.95**	**2.76**	**2.60**	**-1.1%**
Industrial combined heat and power[1]								
Capacity (gigawatts)	26.9	27.6	30.6	32.8	35.8	38.9	40.7	1.5%
Generation (billion kilowatthours)	144	147	170	181	195	211	221	1.5%

[1]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Includes ethane, natural gasoline, and refinery olefins.
[3]Includes lubricants and miscellaneous petroleum products.
[4]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[5]Includes net coal coke imports.
[6]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources.
Btu = British thermal unit.
- - = Not applicable.
Note: Includes estimated consumption for petroleum and other liquids. Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 prices for motor gasoline and distillate fuel oil are based on: U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2014/08) (Washington, DC, August 2014). 2012 and 2013 petrochemical feedstock and asphalt and road oil prices are based on: EIA, *State Energy Data Report 2012*, DOE/EIA-0214(2012) (Washington, DC, June 2014). 2012 and 2013 coal prices are based on: EIA, *Quarterly Coal Report, October-December 2013*, DOE/EIA-0121(2013/4Q) (Washington, DC, March 2014) and EIA, AEO2015 National Energy Modeling System run REF2015.D021915A. 2012 and 2013 electricity prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2012 natural gas prices: EIA, *Natural Gas Annual 2013*, DOE/EIA-0131(2013) (Washington, DC, October 2014). 2013 natural gas prices: *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). 2012 refining consumption values are based on: *Petroleum Supply Annual 2012*, DOE/EIA-0340(2012)/1 (Washington, DC, September 2013). 2013 refining consumption based on: *Petroleum Supply Annual 2013*, DOE/EIA-0340(2013)/1 (Washington, DC, September 2014). Other 2012 and 2013 consumption values are based on: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2012 and 2013 shipments: IHS Economics, Industry model, November 2014. **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A7. Transportation sector key indicators and delivered energy consumption

Key indicators and consumption	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Key indicators								
Travel indicators								
(billion vehicle miles traveled)								
Light-duty vehicles less than 8,501 pounds	2,578	2,644	2,917	3,090	3,287	3,458	3,570	1.1%
Commercial light trucks[1]	62	67	79	85	92	98	105	1.7%
Freight trucks greater than 10,000 pounds	242	268	314	337	355	374	397	1.5%
(billion seat miles available)								
Air	1,033	1,047	1,174	1,279	1,391	1,481	1,557	1.5%
(billion ton miles traveled)								
Rail	1,729	1,758	1,828	1,960	1,999	2,013	2,066	0.6%
Domestic shipping	475	480	467	444	424	416	420	-0.5%
Energy efficiency indicators								
(miles per gallon)								
New light-duty vehicle CAFE standard[2]	29.4	30.0	36.3	46.0	46.3	46.5	46.8	1.7%
New car[2]	33.4	34.1	43.7	54.3	54.3	54.3	54.4	1.7%
New light truck[2]	25.7	26.3	30.9	39.5	39.5	39.5	39.5	1.5%
Compliance new light-duty vehicle[3]	32.7	32.8	37.9	46.7	47.4	47.9	48.1	1.4%
New car[3]	37.0	37.2	44.2	54.6	55.3	55.5	55.5	1.5%
New light truck[3]	28.6	28.8	33.1	40.3	40.7	40.9	40.9	1.3%
Tested new light-duty vehicle[4]	31.7	31.7	37.9	46.6	47.4	47.8	48.1	1.6%
New car[4]	36.3	36.5	44.1	54.6	55.3	55.4	55.5	1.6%
New light truck[4]	27.4	27.6	33.1	40.3	40.7	40.9	40.8	1.5%
On-road new light-duty vehicle[5]	25.6	25.6	30.6	37.7	38.3	38.7	38.9	1.6%
New car[5]	29.6	29.8	36.1	44.6	45.1	45.3	45.3	1.6%
New light truck[5]	22.0	22.1	26.5	32.3	32.6	32.7	32.7	1.5%
Light-duty stock[6]	21.5	21.9	25.0	28.5	32.3	35.1	37.0	2.0%
New commercial light truck[1]	18.1	18.1	20.6	24.2	24.4	24.6	24.6	1.1%
Stock commercial light truck[1]	15.2	15.5	18.0	20.3	22.4	23.8	24.4	1.7%
Freight truck	6.7	6.7	7.2	7.5	7.7	7.8	7.8	0.6%
(seat miles per gallon)								
Aircraft	64.2	65.9	67.4	68.7	70.2	72.0	74.1	0.4%
(ton miles per thousand Btu)								
Rail	3.4	3.5	3.6	3.8	3.9	4.1	4.2	0.7%
Domestic shipping	4.7	4.7	5.0	5.2	5.4	5.6	5.8	0.8%
Energy use by mode (quadrillion Btu)								
Light-duty vehicles	15.00	15.13	14.62	13.57	12.74	12.31	12.08	-0.8%
Commercial light trucks[1]	0.51	0.54	0.55	0.53	0.51	0.52	0.54	0.0%
Bus transportation	0.24	0.26	0.27	0.28	0.29	0.30	0.31	0.6%
Freight trucks	4.98	5.51	6.03	6.19	6.34	6.60	6.98	0.9%
Rail, passenger	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.9%
Rail, freight	0.44	0.51	0.50	0.52	0.51	0.50	0.49	-0.1%
Shipping, domestic	0.10	0.10	0.10	0.09	0.08	0.08	0.07	-1.3%
Shipping, international	0.66	0.62	0.63	0.63	0.64	0.64	0.64	0.1%
Recreational boats	0.23	0.24	0.26	0.28	0.29	0.29	0.30	0.8%
Air	2.33	2.30	2.54	2.73	2.91	3.02	3.08	1.1%
Military use	0.71	0.67	0.63	0.64	0.68	0.72	0.77	0.5%
Lubricants	0.12	0.13	0.14	0.14	0.14	0.14	0.14	0.3%
Pipeline fuel	0.75	0.88	0.85	0.90	0.94	0.94	0.96	0.3%
Total	**26.11**	**26.96**	**27.18**	**26.54**	**26.12**	**26.11**	**26.41**	**-0.1%**

Table A7. Transportation sector key indicators and delivered energy consumption (continued)

Key indicators and consumption	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Energy use by mode (million barrels per day oil equivalent)								
Light-duty vehicles	8.06	8.13	7.85	7.31	6.88	6.67	6.57	-0.8%
Commercial light trucks[1]	0.26	0.28	0.28	0.27	0.26	0.26	0.27	0.0%
Bus transportation	0.11	0.12	0.13	0.14	0.14	0.14	0.15	0.6%
Freight trucks	2.40	2.65	2.90	2.98	3.05	3.18	3.36	0.9%
Rail, passenger	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.9%
Rail, freight	0.21	0.24	0.24	0.25	0.24	0.24	0.23	-0.1%
Shipping, domestic	0.04	0.05	0.05	0.04	0.04	0.04	0.03	-1.3%
Shipping, international	0.29	0.27	0.29	0.29	0.29	0.29	0.29	0.2%
Recreational boats	0.12	0.13	0.14	0.15	0.15	0.16	0.16	0.8%
Air	1.13	1.11	1.23	1.32	1.40	1.46	1.49	1.1%
Military use	0.34	0.32	0.30	0.31	0.33	0.35	0.37	0.5%
Lubricants	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.3%
Pipeline fuel	0.35	0.42	0.40	0.42	0.44	0.44	0.45	0.3%
Total	**13.41**	**13.82**	**13.90**	**13.56**	**13.32**	**13.32**	**13.48**	**-0.1%**

[1]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.
[2]CAFE standard based on projected new vehicle sales.
[3]Includes CAFE credits for alternative fueled vehicle sales and credit banking.
[4]Environmental Protection Agency rated miles per gallon.
[5]Tested new vehicle efficiency revised for on-road performance.
[6]Combined"on-the-road" estimate for all cars and light trucks.
CAFE = Corporate average fuel economy.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014); EIA, Alternatives to Traditional Transportation Fuels 2009 (Part II - User and Fuel Data), April 2011; Federal Highway Administration, *Highway Statistics 2012* (Washington, DC, January 2014); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 33* (Oak Ridge, TN, July 2014); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, June 2014); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC02TV (Washington, DC, December 2004); EIA, U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2010/2009* (Washington, DC, December 2010); and United States Department of Defense, Defense Fuel Supply Center, Factbook (January, 2010). **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A8. Electricity supply, disposition, prices, and emissions
(billion kilowatthours, unless otherwise noted)

Supply, disposition, prices, and emissions	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Net generation by fuel type								
Electric power sector[1]								
Power only[2]								
Coal	1,478	1,550	1,670	1,685	1,674	1,665	1,663	0.3%
Petroleum	18	22	14	15	14	14	15	-1.6%
Natural gas[3]	1,000	894	867	954	1,073	1,143	1,198	1.1%
Nuclear power	769	789	804	808	808	812	833	0.2%
Pumped storage/other[4]	2	3	3	3	3	3	3	-0.1%
Renewable sources[5]	458	483	620	648	679	733	805	1.9%
Distributed generation (natural gas)	0	0	1	1	1	2	2	- -
Total	**3,726**	**3,741**	**3,978**	**4,113**	**4,252**	**4,372**	**4,518**	**0.7%**
Combined heat and power[6]								
Coal	22	22	26	26	26	26	26	0.5%
Petroleum	2	2	1	1	1	1	1	-4.0%
Natural gas	132	126	133	133	134	134	133	0.2%
Renewable sources	5	5	6	7	7	7	8	1.7%
Total	**164**	**158**	**166**	**167**	**168**	**168**	**167**	**0.2%**
Total net electric power sector generation	**3,890**	**3,899**	**4,144**	**4,280**	**4,420**	**4,540**	**4,686**	**0.7%**
Less direct use	13	13	14	14	14	14	14	0.2%
Net available to the grid	**3,877**	**3,886**	**4,131**	**4,267**	**4,406**	**4,527**	**4,672**	**0.7%**
End-use sector[7]								
Coal	13	13	13	13	13	13	13	0.0%
Petroleum	3	3	3	3	3	3	3	-0.4%
Natural gas	95	98	116	134	163	199	235	3.3%
Other gaseous fuels[8]	11	11	19	19	19	19	19	2.1%
Renewable sources[9]	39	42	53	60	70	82	97	3.1%
Other[10]	3	3	3	3	3	3	3	0.0%
Total end-use sector net generation	**164**	**171**	**207**	**233**	**271**	**320**	**370**	**2.9%**
Less direct use	126	132	167	190	225	269	313	3.3%
Total sales to the grid	**38**	**39**	**40**	**43**	**46**	**51**	**56**	**1.4%**
Total net electricity generation by fuel								
Coal	1,514	1,586	1,709	1,724	1,713	1,704	1,702	0.3%
Petroleum	23	27	18	18	18	18	18	-1.6%
Natural gas	1,228	1,118	1,117	1,223	1,371	1,478	1,569	1.3%
Nuclear power	769	789	804	808	808	812	833	0.2%
Renewable sources[5,9]	501	530	679	716	756	823	909	2.0%
Other[11]	19	20	25	25	25	25	25	0.8%
Total net electricity generation	**4,055**	**4,070**	**4,351**	**4,513**	**4,691**	**4,860**	**5,056**	**0.8%**
Net generation to the grid	**3,916**	**3,925**	**4,171**	**4,309**	**4,453**	**4,578**	**4,729**	**0.7%**
Net imports	**47**	**52**	**33**	**35**	**30**	**26**	**32**	**-1.8%**
Electricity sales by sector								
Residential	1,375	1,391	1,423	1,441	1,488	1,533	1,587	0.5%
Commercial	1,327	1,338	1,413	1,461	1,522	1,583	1,659	0.8%
Industrial	986	955	1,096	1,166	1,183	1,188	1,206	0.9%
Transportation	7	7	9	10	12	15	18	3.4%
Total	**3,695**	**3,691**	**3,941**	**4,078**	**4,205**	**4,319**	**4,470**	**0.7%**
Direct use	139	145	180	204	239	283	327	3.1%
Total electricity use	**3,834**	**3,836**	**4,121**	**4,282**	**4,444**	**4,602**	**4,797**	**0.8%**

Table A8. Electricity supply, disposition, prices, and emissions (continued)
(billion kilowatthours, unless otherwise noted)

Supply, disposition, prices, and emissions	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
End-use prices								
(2013 cents per kilowatthour)								
Residential	12.1	12.2	12.9	13.5	13.6	13.9	14.5	0.6%
Commercial	10.2	10.1	10.6	11.1	11.1	11.3	11.8	0.6%
Industrial	6.8	6.9	7.3	7.6	7.7	7.9	8.4	0.7%
Transportation	9.5	9.7	10.3	11.0	11.2	11.6	12.3	0.9%
All sectors average	**10.0**	**10.1**	**10.5**	**11.0**	**11.1**	**11.3**	**11.8**	**0.6%**
(nominal cents per kilowatthour)								
Residential	11.9	12.2	14.6	16.6	18.3	20.5	23.5	2.5%
Commercial	10.1	10.1	12.0	13.6	14.9	16.6	19.1	2.4%
Industrial	6.7	6.9	8.2	9.4	10.3	11.7	13.6	2.6%
Transportation	9.3	9.7	11.7	13.6	15.0	17.0	19.9	2.7%
All sectors average	**9.8**	**10.1**	**11.9**	**13.5**	**14.8**	**16.6**	**19.2**	**2.4%**
Prices by service category								
(2013 cents per kilowatthour)								
Generation	6.5	6.6	6.6	7.0	7.0	7.1	7.6	0.5%
Transmission	0.9	0.9	1.1	1.2	1.2	1.2	1.3	1.2%
Distribution	2.5	2.6	2.8	2.9	2.9	3.0	3.0	0.6%
(nominal cents per kilowatthour)								
Generation	6.4	6.6	7.5	8.6	9.3	10.5	12.3	2.3%
Transmission	0.9	0.9	1.2	1.4	1.6	1.8	2.1	3.0%
Distribution	2.5	2.6	3.2	3.6	3.9	4.4	4.9	2.4%
Electric power sector emissions[1]								
Sulfur dioxide (million short tons)	3.43	3.27	1.42	1.44	1.44	1.47	1.53	-2.8%
Nitrogen oxide (million short tons)	1.68	1.69	1.57	1.57	1.56	1.57	1.57	-0.3%
Mercury (short tons)	26.69	27.94	6.58	6.53	6.43	6.40	6.41	-5.3%

[1]Includes electricity-only and combined heat and power plants that have a regulatory status.
[2]Includes plants that only produce electricity and that have a regulatory status.
[3]Includes electricity generation from fuel cells.
[4]Includes non-biogenic municipal waste. The U.S. Energy Information Administration estimates that in 2013 approximately 7 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy*, (Washington, DC, May 2007).
[5]Includes conventional hydroelectric, geothermal, wood, wood waste, biogenic municipal waste, landfill gas, other biomass, solar, and wind power.
[6]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22 or that have a regulatory status).
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]Includes refinery gas and still gas.
[9]Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power.
[10]Includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
[11]Includes pumped storage, non-biogenic municipal waste, refinery gas, still gas, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 electric power sector generation; sales to the grid; net imports; electricity sales; and electricity end-use prices: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014), and supporting databases. 2012 and 2013 emissions: U.S. Environmental Protection Agency, Clean Air Markets Database. 2012 and 2013 electricity prices by service category: EIA, AEO2015 National Energy Modeling System run REF2015.D021915A. **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A9. Electricity generating capacity
(gigawatts)

Net summer capacity[1]	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Electric power sector[2]								
Power only[3]								
Coal[4]	300.2	296.1	255.4	252.8	252.8	252.8	252.9	-0.6%
Oil and natural gas steam[4,5]	99.2	94.6	87.5	78.3	73.2	69.2	68.2	-1.2%
Combined cycle	185.3	188.3	203.2	211.9	233.6	255.1	281.3	1.5%
Combustion turbine/diesel	136.4	139.6	140.1	144.2	151.8	160.7	172.6	0.8%
Nuclear power[6]	102.1	98.9	101.4	101.4	101.6	102.1	104.9	0.2%
Pumped storage	22.4	22.4	22.4	22.4	22.4	22.4	22.4	0.0%
Fuel cells	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0%
Renewable sources[7]	148.1	153.3	187.1	190.2	196.6	209.7	229.2	1.5%
Distributed generation (natural gas)[8]	0.0	0.0	0.7	1.1	1.7	2.4	3.1	--
Total	**993.7**	**993.2**	**997.9**	**1,002.4**	**1,033.7**	**1,074.4**	**1,134.6**	**0.5%**
Combined heat and power[9]								
Coal	4.5	4.3	4.1	4.1	4.1	4.1	4.1	-0.2%
Oil and natural gas steam[5]	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.0%
Combined cycle	25.7	25.7	26.0	26.0	26.0	26.0	26.0	0.0%
Combustion turbine/diesel	3.1	3.1	3.1	3.1	3.1	3.1	3.1	0.0%
Renewable sources[7]	1.4	1.4	1.4	1.4	1.4	1.4	1.4	0.1%
Total	**35.6**	**35.4**	**35.6**	**35.6**	**35.6**	**35.6**	**35.6**	**0.0%**
Cumulative planned additions[10]								
Coal	--	--	0.7	0.7	0.7	0.7	0.7	--
Oil and natural gas steam[5]	--	--	0.4	0.4	0.4	0.4	0.4	--
Combined cycle	--	--	14.2	14.2	14.2	14.2	14.2	--
Combustion turbine/diesel	--	--	1.6	1.6	1.6	1.6	1.6	--
Nuclear power	--	--	5.5	5.5	5.5	5.5	5.5	--
Pumped storage	--	--	0.0	0.0	0.0	0.0	0.0	--
Fuel cells	--	--	0.0	0.0	0.0	0.0	0.0	--
Renewable sources[7]	--	--	30.5	30.5	30.5	30.5	30.5	--
Distributed generation[8]	--	--	0.0	0.0	0.0	0.0	0.0	--
Total	**--**	**--**	**52.8**	**52.8**	**52.8**	**52.8**	**52.8**	**--**
Cumulative unplanned additions[10]								
Coal	--	--	0.3	0.3	0.3	0.3	0.4	--
Oil and natural gas steam[5]	--	--	0.0	0.0	0.0	0.0	0.0	--
Combined cycle	--	--	7.7	17.3	39.0	60.5	86.9	--
Combustion turbine/diesel	--	--	3.8	8.5	16.8	26.1	37.9	--
Nuclear power	--	--	0.0	0.0	0.1	0.6	3.5	--
Pumped storage	--	--	0.0	0.0	0.0	0.0	0.0	--
Fuel cells	--	--	0.0	0.0	0.0	0.0	0.0	--
Renewable sources[7]	--	--	4.0	7.1	13.4	26.6	46.1	--
Distributed generation[8]	--	--	0.7	1.1	1.7	2.4	3.1	--
Total	**--**	**--**	**16.5**	**34.3**	**71.4**	**116.5**	**177.9**	**--**
Cumulative electric power sector additions[10]	**--**	**--**	**69.3**	**87.1**	**124.2**	**169.4**	**230.7**	**--**
Cumulative retirements[11]								
Coal	--	--	37.4	40.1	40.1	40.1	40.1	--
Oil and natural gas steam[5]	--	--	11.8	21.0	26.1	30.1	31.0	--
Combined cycle	--	--	7.1	8.0	8.0	8.0	8.3	--
Combustion turbine/diesel	--	--	4.9	5.5	6.1	6.5	6.5	--
Nuclear power	--	--	3.2	3.2	3.2	3.2	3.2	--
Pumped storage	--	--	0.0	0.0	0.0	0.0	0.0	--
Fuel cells	--	--	0.0	0.0	0.0	0.0	0.0	--
Renewable sources[7]	--	--	0.6	0.6	0.6	0.6	0.6	--
Total	**--**	**--**	**65.0**	**78.3**	**84.1**	**88.5**	**89.7**	**--**
Total electric power sector capacity	**1,029**	**1,029**	**1,033**	**1,038**	**1,069**	**1,110**	**1,170**	**0.5%**

Table A9. Electricity generating capacity (continued)
(gigawatts)

Net summer capacity[1]	Reference case 2012	2013	2020	2025	2030	2035	2040	Annual growth 2013-2040 (percent)
End-use generators[12]								
Coal	3.4	3.4	3.4	3.4	3.4	3.4	3.4	0.0%
Petroleum	0.9	0.9	0.9	0.9	0.9	0.9	0.9	-0.4%
Natural gas	16.3	16.9	19.5	22.7	27.6	33.6	38.9	3.1%
Other gaseous fuels[13]	2.1	2.1	2.8	2.8	2.8	2.8	2.8	1.0%
Renewable sources[7]	10.4	12.1	18.2	22.4	28.6	36.0	44.6	4.9%
Other[14]	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0%
Total	**33.6**	**36.0**	**45.3**	**52.8**	**63.8**	**77.2**	**91.1**	**3.5%**
Cumulative capacity additions[10]	--	--	**10.5**	**18.0**	**29.1**	**42.6**	**56.5**	--

[1]Net summer capacity is the steady hourly output that generating equipment is expected to supply to system load (exclusive of auxiliary power), as demonstrated by tests during summer peak demand.
[2]Includes electricity-only and combined heat and power plants that have a regulatory status.
[3]Includes plants that only produce electricity and that have a regulatory status. Includes capacity increases (uprates) at existing units.
[4]Coal and oil and natural gas steam capacity reflect the impact of 4.1 GW of existing coal capacity converting to gas steam capacity.
[5]Includes oil-, gas-, and dual-fired capacity.
[6]Nuclear capacity includes 0.2 gigawatts of uprates.
[7]Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
[8]Primarily peak load capacity fueled by natural gas.
[9]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22 or that have a regulatory status).
[10]Cumulative additions after December 31, 2013.
[11]Cumulative retirements after December 31, 2013.
[12]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[13]Includes refinery gas and still gas.
[14]Includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 capacity and projected planned additions: U.S. Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A10. Electricity trade
(billion kilowatthours, unless otherwise noted)

Electricity trade	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Interregional electricity trade								
Gross domestic sales								
Firm power	156	157	122	63	28	28	28	-6.2%
Economy	184	115	195	214	207	232	268	3.2%
Total	**340**	**272**	**318**	**277**	**235**	**260**	**296**	**0.3%**
Gross domestic sales (million 2013 dollars)								
Firm power	9,711	9,802	7,622	3,952	1,722	1,722	1,722	-6.2%
Economy	6,217	4,772	9,376	11,934	11,963	14,056	18,159	5.1%
Total	**15,929**	**14,574**	**16,998**	**15,886**	**13,685**	**15,778**	**19,881**	**1.2%**
International electricity trade								
Imports from Canada and Mexico								
Firm power	15.9	15.8	20.4	16.4	14.0	14.0	14.0	-0.5%
Economy	43.1	47.9	28.0	34.4	30.6	26.2	32.1	-1.5%
Total	**59.0**	**63.7**	**48.4**	**50.7**	**44.6**	**40.2**	**46.1**	**-1.2%**
Exports to Canada and Mexico								
Firm power	2.7	2.3	1.5	0.5	0.0	0.0	0.0	- -
Economy	8.8	9.1	14.0	14.7	14.7	14.4	14.4	1.7%
Total	**11.5**	**11.4**	**15.4**	**15.2**	**14.7**	**14.4**	**14.4**	**0.9%**

- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports. Firm power sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.
Sources: 2012 and 2013 interregional firm electricity trade data: 2013 seasonal reliability assessments from North American Electric Reliability Council regional entities and Independent System Operators. 2012 and 2013 interregional economy electricity trade are model results. 2012 and 2013 Mexican electricity trade data: U.S. Energy Information Administration (EIA), *Electric Power Annual 2012*, DOE/EIA-0348(2012) (Washington, DC, December 2013). 2012 Canadian international electricity trade data: National Energy Board, *Electricity Exports and Imports Statistics, 2012*. 2013 Canadian international electricity trade data: National Energy Board, *Electricity Exports and Imports Statistics, 2013*. **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A11. Petroleum and other liquids supply and disposition
(million barrels per day, unless otherwise noted)

Supply and disposition	Reference case 2012	2013	2020	2025	2030	2035	2040	Annual growth 2013-2040 (percent)
Crude oil								
Domestic crude production[1]	6.50	7.44	10.60	10.28	10.04	9.38	9.43	0.9%
Alaska	0.53	0.52	0.42	0.32	0.24	0.18	0.34	-1.6%
Lower 48 states	5.98	6.92	10.18	9.96	9.80	9.20	9.09	1.0%
Net imports	8.46	7.60	5.51	6.09	6.44	7.35	7.58	0.0%
Gross imports	8.53	7.73	6.14	6.72	7.07	7.98	8.21	0.2%
Exports	0.07	0.13	0.63	0.63	0.63	0.63	0.63	5.9%
Other crude supply[2]	0.04	0.27	0.00	0.00	0.00	0.00	0.00	- -
Total crude supply	**15.00**	**15.30**	**16.11**	**16.37**	**16.48**	**16.73**	**17.01**	**0.4%**
Net product imports	-1.05	-1.37	-2.80	-3.24	-3.56	-3.94	-4.26	- -
Gross refined product imports[3]	0.82	0.82	1.21	1.28	1.31	1.31	1.26	1.6%
Unfinished oil imports	0.60	0.66	0.60	0.56	0.52	0.49	0.45	-1.4%
Blending component imports	0.62	0.60	0.59	0.55	0.49	0.45	0.40	-1.5%
Exports	3.08	3.43	5.20	5.63	5.89	6.18	6.36	2.3%
Refinery processing gain[4]	1.06	1.09	0.98	1.00	0.97	0.99	0.98	-0.4%
Product stock withdrawal	-0.07	0.11	0.00	0.00	0.00	0.00	0.00	- -
Natural gas plant liquids	2.41	2.61	4.04	4.16	4.19	4.13	4.07	1.7%
Supply from renewable sources	0.88	0.93	1.01	1.01	1.01	1.04	1.12	0.7%
Ethanol	0.82	0.83	0.84	0.84	0.84	0.87	0.95	0.5%
Domestic production	0.84	0.85	0.86	0.86	0.86	0.87	0.93	0.4%
Net imports	-0.02	-0.02	-0.02	-0.02	-0.02	0.00	0.02	- -
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Biodiesel	0.06	0.10	0.14	0.11	0.11	0.11	0.11	0.4%
Domestic production	0.06	0.09	0.13	0.10	0.10	0.10	0.10	0.3%
Net imports	-0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.9%
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Other biomass-derived liquids[5]	0.00	0.00	0.03	0.06	0.06	0.06	0.06	31.9%
Domestic production	0.00	0.00	0.03	0.06	0.06	0.06	0.06	31.9%
Net imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Liquids from gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Liquids from coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Other[6]	0.19	0.21	0.28	0.29	0.30	0.31	0.32	1.6%
Total primary supply[7]	**18.43**	**18.87**	**19.62**	**19.59**	**19.38**	**19.26**	**19.24**	**0.1%**
Product supplied								
by fuel								
Liquefied petroleum gases and other[8]	2.30	2.50	2.91	3.19	3.30	3.27	3.25	1.0%
Motor gasoline[9]	8.69	8.85	8.49	7.89	7.41	7.16	7.05	-0.8%
of which: E85[10]	0.01	0.01	0.02	0.08	0.13	0.16	0.19	9.9%
Jet fuel[11]	1.40	1.43	1.55	1.64	1.75	1.82	1.87	1.0%
Distillate fuel oil[12]	3.74	3.83	4.26	4.31	4.34	4.38	4.38	0.5%
of which: Diesel	3.46	3.56	3.94	4.02	4.09	4.15	4.17	0.6%
Residual fuel oil	0.37	0.32	0.27	0.28	0.28	0.28	0.28	-0.4%
Other[13]	1.97	2.04	2.18	2.30	2.33	2.37	2.43	0.7%
by sector								
Residential and commercial	0.82	0.86	0.76	0.71	0.67	0.64	0.61	-1.3%
Industrial[14]	4.49	4.69	5.50	5.90	6.04	6.04	6.09	1.0%
Transportation	13.04	13.36	13.46	13.08	12.79	12.71	12.66	-0.2%
Electric power[15]	0.10	0.12	0.08	0.08	0.08	0.08	0.08	-1.4%
Unspecified sector[16]	0.02	-0.12	-0.15	-0.16	-0.17	-0.17	-0.17	- -
Total product supplied	**18.47**	**18.96**	**19.65**	**19.61**	**19.41**	**19.29**	**19.27**	**0.1%**
Discrepancy[17]	-0.03	-0.10	-0.03	-0.02	-0.03	-0.03	-0.03	- -

Table A11. Petroleum and other liquids supply and disposition (continued)
(million barrels per day, unless otherwise noted)

Supply and disposition	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Domestic refinery distillation capacity[18]	17.4	17.8	18.8	18.8	18.8	18.8	18.8	0.2%
Capacity utilization rate (percent)[19]	88.7	88.3	87.8	89.0	89.4	90.7	92.0	0.2%
Net import share of product supplied (percent)	40.1	33.0	13.7	14.5	14.8	17.7	17.4	-2.3%
Net expenditures for imported crude oil and petroleum products (billion 2013 dollars)	345	308	167	211	259	339	405	1.0%

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude oil stock withdrawals.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes pyrolysis oils, biomass-derived Fischer-Tropsch liquids, biobutanol, and renewable feedstocks used for the on-site production of diesel and gasoline.
[6]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[7]Total crude supply, net product imports, refinery processing gain, product stock withdrawal, natural gas plant liquids, supply from renewable sources, liquids from gas, liquids from coal, and other supply.
[8]Includes ethane, natural gasoline, and refinery olefins.
[9]Includes ethanol and ethers blended into gasoline.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes only kerosene type.
[12]Includes distillate fuel oil from petroleum and biomass feedstocks.
[13]Includes kerosene, aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, and miscellaneous petroleum products.
[14]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[15]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[16]Represents consumption unattributed to the sectors above.
[17]Balancing item. Includes unaccounted for supply, losses, and gains.
[18]End-of-year operable capacity.
[19]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 product supplied based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). Other 2012 data: EIA, *Petroleum Supply Annual 2012*, DOE/EIA-0340(2012)/1 (Washington, DC, September 2013). Other 2013 data: EIA, *Petroleum Supply Annual 2013*, DOE/EIA-0340(2013)/1 (Washington, DC, September 2014). **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A12. Petroleum and other liquids prices
(2013 dollars per gallon, unless otherwise noted)

Sector and fuel	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Crude oil prices (2013 dollars per barrel)								
Brent spot	113	109	79	91	106	122	141	1.0%
West Texas Intermediate spot	96	98	73	85	99	116	136	1.2%
Average imported refiners acquisition cost[1]	103	98	71	82	96	112	131	1.1%
Brent / West Texas Intermediate spread	17.8	10.7	6.2	6.1	6.2	6.0	5.6	-2.4%
Delivered sector product prices								
Residential								
Propane	2.22	2.13	2.10	2.16	2.23	2.33	2.43	0.5%
Distillate fuel oil	3.79	3.78	2.99	3.28	3.65	4.08	4.56	0.7%
Commercial								
Distillate fuel oil	3.69	3.68	2.89	3.20	3.56	3.99	4.47	0.7%
Residual fuel oil	3.43	3.31	2.12	2.39	2.71	3.08	3.64	0.4%
Residual fuel oil (2013 dollars per barrel)	144	139	89	101	114	129	153	0.4%
Industrial[2]								
Propane	1.95	1.85	1.79	1.87	1.96	2.09	2.24	0.7%
Distillate fuel oil	3.76	3.75	2.91	3.23	3.58	4.00	4.49	0.7%
Residual fuel oil	3.09	3.00	2.00	2.27	2.58	2.95	3.51	0.6%
Residual fuel oil (2013 dollars per barrel)	130	126	84	95	108	124	147	0.6%
Transportation								
Propane	2.31	2.24	2.19	2.25	2.32	2.42	2.52	0.4%
E85[3]	3.39	3.14	2.90	2.77	2.98	3.16	3.38	0.3%
Ethanol wholesale price	2.58	2.37	2.49	2.47	2.35	2.49	2.64	0.4%
Motor gasoline[4]	3.72	3.55	2.74	2.95	3.20	3.53	3.90	0.3%
Jet fuel[5]	3.10	2.94	2.17	2.47	2.88	3.31	3.81	1.0%
Diesel fuel (distillate fuel oil)[6]	3.94	3.86	3.17	3.49	3.84	4.26	4.75	0.8%
Residual fuel oil	3.00	2.89	1.74	2.00	2.30	2.64	3.03	0.2%
Residual fuel oil (2013 dollars per barrel)	126	122	73	84	97	111	127	0.2%
Electric power[7]								
Distillate fuel oil	3.34	3.33	2.60	2.90	3.28	3.70	4.19	0.9%
Residual fuel oil	3.12	2.83	1.71	1.99	2.30	2.67	3.23	0.5%
Residual fuel oil (2013 dollars per barrel)	131	119	72	83	97	112	136	0.5%
Average prices, all sectors[8]								
Propane	2.09	2.00	1.93	1.99	2.06	2.18	2.30	0.5%
Motor gasoline[4]	3.70	3.53	2.74	2.95	3.20	3.53	3.90	0.4%
Jet fuel[5]	3.10	2.94	2.17	2.47	2.88	3.31	3.81	1.0%
Distillate fuel oil	3.89	3.83	3.11	3.43	3.78	4.20	4.69	0.8%
Residual fuel oil	3.04	2.90	1.83	2.10	2.40	2.75	3.22	0.4%
Residual fuel oil (2013 dollars per barrel)	128	122	77	88	101	116	135	0.4%
Average	**3.29**	**3.16**	**2.46**	**2.65**	**2.89**	**3.23**	**3.62**	**0.5%**

Table A12. Petroleum and other liquids prices (continued)
(nominal dollars per gallon, unless otherwise noted)

Sector and fuel	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Crude oil prices (nominal dollars per barrel)								
Brent spot	112	109	90	112	142	180	229	2.8%
West Texas Intermediate spot	94	98	83	105	133	171	220	3.0%
Average imported refiners acquisition cost[1]	101	98	80	102	129	165	212	2.9%
Delivered sector product prices								
Residential								
Propane	2.19	2.13	2.38	2.66	2.99	3.42	3.94	2.3%
Distillate fuel oil	3.73	3.78	3.39	4.04	4.90	5.99	7.40	2.5%
Commercial								
Distillate fuel oil	3.63	3.68	3.28	3.94	4.78	5.86	7.25	2.5%
Residual fuel oil	3.38	3.31	2.41	2.95	3.63	4.53	5.90	2.2%
Residual fuel oil (nominal dollars per barrel)	142	139	101	124	153	190	248	2.2%
Industrial[2]								
Propane	1.92	1.85	2.04	2.30	2.63	3.08	3.62	2.5%
Distillate fuel oil	3.71	3.75	3.30	3.98	4.80	5.89	7.28	2.5%
Residual fuel oil	3.05	3.00	2.26	2.79	3.46	4.34	5.69	2.4%
Residual fuel oil (nominal dollars per barrel)	128	126	95	117	145	182	239	2.4%
Transportation								
Propane	2.28	2.24	2.49	2.78	3.12	3.56	4.09	2.2%
E85[3]	3.34	3.14	3.29	3.41	3.99	4.65	5.48	2.1%
Ethanol wholesale price	2.55	2.37	2.83	3.04	3.15	3.67	4.27	2.2%
Motor gasoline[4]	3.67	3.55	3.10	3.63	4.29	5.18	6.32	2.2%
Jet fuel[5]	3.06	2.94	2.47	3.05	3.86	4.87	6.18	2.8%
Diesel fuel (distillate fuel oil)[6]	3.89	3.86	3.60	4.30	5.15	6.26	7.70	2.6%
Residual fuel oil	2.95	2.89	1.98	2.46	3.08	3.88	4.92	2.0%
Residual fuel oil (nominal dollars per barrel)	124	122	83	103	129	163	207	2.0%
Electric power[7]								
Distillate fuel oil	3.29	3.33	2.95	3.57	4.39	5.45	6.79	2.7%
Residual fuel oil	3.07	2.83	1.94	2.45	3.09	3.93	5.24	2.3%
Residual fuel oil (nominal dollars per barrel)	129	119	82	103	130	165	220	2.3%
Average prices, all sectors[8]								
Propane	2.06	2.00	2.19	2.45	2.77	3.20	3.73	2.3%
Motor gasoline[4]	3.64	3.53	3.10	3.63	4.29	5.18	6.32	2.2%
Jet fuel[5]	3.06	2.94	2.47	3.05	3.86	4.87	6.18	2.8%
Distillate fuel oil	3.83	3.83	3.52	4.22	5.07	6.18	7.61	2.6%
Residual fuel oil	2.99	2.90	2.07	2.58	3.22	4.04	5.21	2.2%
Residual fuel oil (nominal dollars per barrel)	126	122	87	108	135	170	219	2.2%
Average	**3.24**	**3.16**	**2.79**	**3.26**	**3.88**	**4.75**	**5.86**	**2.3%**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
[5]Includes only kerosene type.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Includes electricity-only and combined heat and power plants that have a regulatory status.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 Brent and West Texas Intermediate crude oil spot prices: Thomson Reuters. 2012 and 2013 average imported crude oil price: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2012 and 2013 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380(2014/08) (Washington, DC, August 2014). 2012 and 2013 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2012 and 2013 electric power prices based on: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2012 and 2013 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2012 and 2013 wholesale ethanol prices derived from Bloomberg U.S. average rack price. **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A13. Natural gas supply, disposition, and prices
(trillion cubic feet per year, unless otherwise noted)

Supply, disposition, and prices	Reference case 2012	2013	2020	2025	2030	2035	2040	Annual growth 2013-2040 (percent)
Supply								
Dry gas production[1]	24.06	24.40	28.82	30.51	33.01	34.14	35.45	1.4%
Supplemental natural gas[2]	0.06	0.05	0.06	0.06	0.06	0.06	0.06	0.6%
Net imports	1.52	1.29	-2.55	-3.50	-4.81	-5.19	-5.62	- -
Pipeline[3]	1.37	1.20	-0.48	-1.01	-1.52	-1.90	-2.33	- -
Liquefied natural gas	0.15	0.09	-2.08	-2.49	-3.29	-3.29	-3.29	- -
Total supply	**25.64**	**25.75**	**26.33**	**27.07**	**28.27**	**29.01**	**29.90**	**0.6%**
Consumption by sector								
Residential	4.15	4.92	4.50	4.42	4.40	4.31	4.20	-0.6%
Commercial	2.90	3.28	3.21	3.20	3.33	3.47	3.61	0.4%
Industrial[4]	7.21	7.41	8.10	8.24	8.41	8.52	8.66	0.6%
Natural-gas-to-liquids heat and power[5]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural gas to liquids production[6]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electric power[7]	9.11	8.16	7.61	8.13	8.81	9.17	9.38	0.5%
Transportation[8]	0.04	0.05	0.07	0.10	0.17	0.31	0.70	10.3%
Pipeline fuel	0.73	0.86	0.83	0.87	0.91	0.92	0.93	0.3%
Lease and plant fuel[9]	1.40	1.48	1.82	1.92	2.05	2.12	2.23	1.5%
Total consumption	**25.53**	**26.16**	**26.14**	**26.88**	**28.08**	**28.82**	**29.70**	**0.5%**
Discrepancy[10]	**0.11**	**-0.41**	**0.19**	**0.19**	**0.19**	**0.19**	**0.19**	- -
Natural gas spot price at Henry Hub								
(2013 dollars per million Btu)	2.79	3.73	4.88	5.46	5.69	6.60	7.85	2.8%
(nominal dollars per million Btu)	2.75	3.73	5.54	6.72	7.63	9.70	12.73	4.7%
Delivered prices								
(2013 dollars per thousand cubic feet)								
Residential	10.86	10.29	11.92	13.07	13.15	14.13	15.90	1.6%
Commercial	8.36	8.35	9.82	10.83	10.69	11.44	12.97	1.6%
Industrial[4]	3.94	4.68	6.35	7.07	6.99	7.75	9.03	2.5%
Electric power[7]	3.59	4.51	5.52	6.43	6.38	7.15	8.49	2.4%
Transportation[11]	20.93	18.13	18.27	17.23	16.13	17.60	20.18	0.4%
Average[12]	**5.61**	**6.32**	**7.66**	**8.50**	**8.40**	**9.22**	**10.76**	**2.0%**
(nominal dollars per thousand cubic feet)								
Residential	10.70	10.29	13.52	16.09	17.62	20.77	25.77	3.5%
Commercial	8.24	8.35	11.14	13.34	14.33	16.81	21.03	3.5%
Industrial[4]	3.88	4.68	7.20	8.71	9.37	11.39	14.64	4.3%
Electric power[7]	3.54	4.51	6.26	7.92	8.55	10.51	13.76	4.2%
Transportation[11]	20.62	18.13	20.73	21.21	21.62	25.87	32.72	2.2%
Average[12]	**5.53**	**6.32**	**8.68**	**10.46**	**11.27**	**13.55**	**17.44**	**3.8%**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida, as well as gas from Canada and Mexico.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems. Excludes use for lease and plant fuel.
[5]Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
[6]Includes any natural gas converted into liquid fuel.
[7]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[8]Natural gas used as fuel in motor vehicles, trains, and ships.
[9]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[10]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2012 and 2013 values include net storage injections.
[11]Natural gas used as fuel in motor vehicles, trains, and ships. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[12]Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 supply values; lease, plant, and pipeline fuel consumption; and residential, commercial, and industrial delivered prices: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2013*, DOE/EIA-0131(2013) (Washington, DC, October 2014). 2013 supply values; lease, plant, and pipeline fuel consumption; and residential, commercial, and industrial delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). Other 2012 and 2013 consumption based on: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2012 and 2013 natural gas spot price at Henry Hub: Thomson Reuters. 2012 and 2013 electric power prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2013 and April 2014, Table 4.2, and EIA, *State Energy Data Report 2012*, DOE/EIA-0214(2012) (Washington, DC, June 2014). 2012 transportation sector delivered prices are based on: EIA, *Natural Gas Annual 2013*, DOE/EIA-0131(2013) (Washington, DC, October 2014), EIA, *State Energy Data Report 2012*, DOE/EIA-0214(2012) (Washington, DC, June 2014), and estimated State and Federal motor fuel taxes and dispensing costs or charges. 2013 transportation sector delivered prices are model results. **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A14. Oil and gas supply

Production and supply	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Crude oil								
Lower 48 average wellhead price[1] (2013 dollars per barrel)	**96**	**97**	**75**	**87**	**101**	**117**	**136**	**1.3%**
Production (million barrels per day)[2]								
United States total	6.50	7.44	10.60	10.28	10.04	9.38	9.43	0.9%
Lower 48 onshore	4.60	5.57	8.03	8.01	7.60	7.07	6.92	0.8%
Tight oil[3]	2.19	3.15	5.60	5.31	4.83	4.40	4.29	1.1%
Carbon dioxide enhanced oil recovery	0.26	0.28	0.35	0.47	0.58	0.69	0.83	4.1%
Other	2.12	2.14	2.08	2.23	2.19	1.98	1.80	-0.6%
Lower 48 offshore	1.38	1.36	2.15	1.95	2.21	2.14	2.17	1.7%
State	0.07	0.07	0.05	0.04	0.03	0.03	0.02	-3.8%
Federal	1.31	1.29	2.10	1.92	2.18	2.11	2.14	1.9%
Alaska	0.53	0.52	0.42	0.32	0.24	0.18	0.34	-1.6%
Onshore	0.47	0.45	0.30	0.23	0.18	0.14	0.12	-4.9%
State offshore	0.06	0.06	0.12	0.09	0.06	0.04	0.02	-3.6%
Federal offshore	0.00	0.00	0.00	0.00	0.00	0.00	0.20	15.9%
Lower 48 end of year reserves[2] (billion barrels)	**30.1**	**29.4**	**37.4**	**39.4**	**42.6**	**43.4**	**44.8**	**1.6%**
Natural gas plant liquids production *(million barrels per day)*								
United States total	2.41	2.61	4.04	4.16	4.20	4.13	4.07	1.7%
Lower 48 onshore	2.18	2.39	3.82	3.94	3.92	3.87	3.79	1.7%
Lower 48 offshore	0.20	0.18	0.19	0.20	0.26	0.25	0.26	1.3%
Alaska	0.03	0.03	0.02	0.02	0.01	0.01	0.02	-1.4%
Natural gas								
Natural gas spot price at Henry Hub (2013 dollars per million Btu)	2.79	3.73	4.88	5.46	5.69	6.60	7.85	2.8%
Dry production (trillion cubic feet)[4]								
United States total	24.06	24.40	28.82	30.51	33.01	34.14	35.45	1.4%
Lower 48 onshore	22.16	22.63	26.52	28.10	29.05	30.26	31.49	1.2%
Tight gas	4.78	4.38	5.21	5.55	5.99	6.40	6.97	1.7%
Shale gas and tight oil plays[3]	10.16	11.34	15.44	17.03	17.85	18.85	19.58	2.0%
Coalbed methane	1.64	1.29	1.45	1.32	1.24	1.24	1.25	-0.1%
Other	5.58	5.61	4.42	4.19	3.97	3.77	3.69	-1.5%
Lower 48 offshore	1.57	1.46	2.03	2.16	2.79	2.73	2.81	2.5%
State	0.14	0.11	0.06	0.04	0.03	0.02	0.02	-5.9%
Federal	1.42	1.35	1.98	2.13	2.76	2.70	2.79	2.7%
Alaska	0.33	0.32	0.27	0.25	1.18	1.16	1.15	4.9%
Onshore	0.33	0.32	0.27	0.25	1.18	1.16	1.15	4.9%
State offshore	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Federal offshore	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lower 48 end of year dry reserves[4] (trillion cubic feet)	**298**	**293**	**309**	**316**	**329**	**338**	**345**	**0.6%**
Supplemental gas supplies (trillion cubic feet)[5]	**0.06**	**0.05**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.6%**
Total lower 48 wells drilled (thousands)	**44.7**	**44.5**	**43.4**	**47.4**	**52.1**	**54.0**	**56.7**	**0.9%**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Tight oil represents resources in low-permeability reservoirs, including shale and chalk formations. The specific plays included in the tight oil category are Bakken/Three Forks/Sanish, Eagle Ford, Woodford, Austin Chalk, Spraberry, Niobrara, Avalon/Bone Springs, and Monterey.
[4]Marketed production (wet) minus extraction losses.
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 crude oil lower 48 average wellhead price: U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2014/08) (Washington, DC, August 2014). 2012 and 2013 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 2013*, DOE/EIA-0340(2013)/1 (Washington, DC, September 2014). 2012 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(2012) (Washington, DC, April 2014). 2012 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Annual 2013*, DOE/EIA-0131(2013) (Washington, DC, October 2014). 2012 and 2013 natural gas spot price at Henry Hub: Thomson Reuters. 2013 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). Other 2012 and 2013 values: EIA, Office of Energy Analysis. **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A15. Coal supply, disposition, and prices
(million short tons per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Production[1]								
Appalachia	293	272	260	248	243	235	228	-0.6%
Interior	180	183	219	235	258	278	300	1.8%
West	543	530	592	622	617	597	589	0.4%
East of the Mississippi	423	407	428	426	442	453	467	0.5%
West of the Mississippi	593	578	643	679	676	658	650	0.4%
Total	**1,016**	**985**	**1,071**	**1,105**	**1,118**	**1,111**	**1,117**	**0.5%**
Waste coal supplied[2]	**11**	**10**	**11**	**10**	**10**	**10**	**10**	**0.0%**
Net imports								
Imports[3]	8	7	1	1	1	1	1	-6.8%
Exports	126	118	95	112	130	131	141	0.7%
Total	**-118**	**-110**	**-94**	**-110**	**-129**	**-130**	**-140**	**0.9%**
Total supply[4]	**909**	**885**	**987**	**1,005**	**999**	**990**	**988**	**0.4%**
Consumption by sector								
Commercial and institutional	2	2	2	2	2	2	2	0.5%
Coke plants	21	21	21	21	20	19	18	-0.7%
Other industrial[5]	43	43	47	47	48	48	49	0.5%
Coal-to-liquids heat and power	0	0	0	0	0	0	0	- -
Coal to liquids production	0	0	0	0	0	0	0	- -
Electric power[6]	824	858	917	935	930	921	919	0.3%
Total	**889**	**925**	**987**	**1,005**	**999**	**990**	**988**	**0.2%**
Discrepancy and stock change[7]	**20**	**-40**	**0**	**0**	**0**	**0**	**0**	**- -**
Average minemouth price[8]								
(2013 dollars per short ton)	40.5	37.2	37.9	40.3	43.7	46.7	49.2	1.0%
(2013 dollars per million Btu)	2.01	1.84	1.88	2.02	2.18	2.32	2.44	1.0%
Delivered prices[9]								
(2013 dollars per short ton)								
Commercial and institutional	92.1	90.5	86.4	89.2	92.0	95.0	99.2	0.3%
Coke plants	193.4	157.0	165.8	177.7	189.5	197.3	204.4	1.0%
Other industrial[5]	71.4	69.3	70.3	73.6	76.5	79.1	82.5	0.6%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electric power[6]								
(2013 dollars per short ton)	46.5	45.2	45.7	48.2	50.6	53.1	55.6	0.8%
(2013 dollars per million Btu)	2.41	2.34	2.38	2.54	2.67	2.79	2.92	0.8%
Average	**51.5**	**49.1**	**49.5**	**52.2**	**54.7**	**57.1**	**59.7**	**0.7%**
Exports[10]	120.2	95.1	100.9	107.2	112.7	118.9	120.7	0.9%

Table A15. Coal supply, disposition, and prices (continued)
(million short tons per year, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Average minemouth price[8]								
(nominal dollars per short ton)	40.0	37.2	43.0	49.7	58.6	68.6	79.8	2.9%
(nominal dollars per million Btu)	1.98	1.84	2.14	2.48	2.92	3.41	3.96	2.9%
Delivered prices[9]								
(nominal dollars per short ton)								
Commercial and institutional	90.8	90.5	98.0	109.9	123.4	139.7	160.8	2.2%
Coke plants	190.6	157.0	188.0	218.7	254.0	289.9	331.3	2.8%
Other industrial[5]	70.3	69.3	79.7	90.7	102.5	116.3	133.8	2.5%
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -
Electric power[6]								
(nominal dollars per short ton)	45.8	45.2	51.8	59.4	67.9	78.0	90.1	2.6%
(nominal dollars per million Btu)	2.37	2.34	2.70	3.13	3.58	4.10	4.73	2.6%
Average	**50.7**	**49.1**	**56.2**	**64.3**	**73.3**	**84.0**	**96.8**	**2.6%**
Exports[10]	118.4	95.1	114.4	131.9	151.1	174.7	195.6	2.7%

[1]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[2]Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[4]Production plus waste coal supplied plus net imports.
[5]Includes consumption for combined heat and power plants that have a non-regulatory status, and small on-site generating systems. Excludes all coal use in the coal-to-liquids process.
[6]Includes all electricity-only and combined heat and power plants that have a regulatory status.
[7]Balancing item: the sum of production, net imports, and waste coal supplied minus total consumption.
[8]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[9]Prices weighted by consumption; weighted average excludes commercial and institutional prices, and export free-alongside-ship prices.
[10]Free-alongside-ship price at U.S. port of exit.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 data based on: U.S. Energy Information Administration (EIA), *Annual Coal Report 2013*, DOE/EIA-0584(2013) (Washington, DC, January 2015); EIA, *Quarterly Coal Report, October-December 2013*, DOE/EIA-0121(2013/4Q) (Washington, DC, March 2014); and EIA, AEO2015 National Energy Modeling System run REF2015.D021915A. **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A16. Renewable energy generating capacity and generation
(gigawatts, unless otherwise noted)

Net summer capacity and generation	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Electric power sector[1]								
Net summer capacity								
Conventional hydroelectric power	78.1	78.3	79.2	79.6	79.7	79.8	80.1	0.1%
Geothermal[2]	2.6	2.6	3.8	5.3	7.0	8.2	9.1	4.7%
Municipal waste[3]	3.6	3.7	3.8	3.8	3.8	3.8	3.8	0.1%
Wood and other biomass[4]	2.9	3.3	3.5	3.5	3.6	4.2	5.5	1.8%
Solar thermal	0.5	1.3	1.8	1.8	1.8	1.8	1.8	1.2%
Solar photovoltaic[5]	2.6	5.2	14.4	14.7	15.7	17.9	22.2	5.5%
Wind	59.2	60.3	82.0	83.0	86.3	95.6	108.2	2.2%
Offshore wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Total electric power sector capacity	**149.4**	**154.7**	**188.6**	**191.6**	**198.0**	**211.2**	**230.6**	**1.5%**
Generation (billion kilowatthours)								
Conventional hydroelectric power	273.9	265.7	291.0	292.8	293.4	293.8	295.6	0.4%
Geothermal[2]	15.6	16.5	26.8	38.5	52.4	62.3	69.6	5.5%
Biogenic municipal waste[6]	16.9	16.5	20.0	20.3	20.1	20.0	20.2	0.8%
Wood and other biomass	11.1	12.2	24.7	36.2	40.4	47.1	58.8	6.0%
Dedicated plants	9.9	11.1	13.4	15.1	16.7	20.4	30.3	3.8%
Cofiring	1.2	1.1	11.3	21.1	23.7	26.7	28.5	12.7%
Solar thermal	0.9	0.9	3.6	3.6	3.6	3.6	3.6	5.1%
Solar photovoltaic[5]	3.3	8.0	29.7	30.3	32.6	37.6	47.1	6.8%
Wind	140.7	167.6	230.6	233.8	243.3	276.1	317.1	2.4%
Offshore wind	0.0	0.0	0.1	0.1	0.1	0.1	0.1	- -
Total electric power sector generation	**462.3**	**487.4**	**626.4**	**655.6**	**685.9**	**740.7**	**812.1**	**1.9%**
End-use sectors[7]								
Net summer capacity								
Conventional hydroelectric power	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.0%
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Municipal waste[8]	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.0%
Biomass	4.9	5.0	5.4	5.4	5.4	5.5	5.6	0.4%
Solar photovoltaic[5]	4.6	6.2	11.4	15.5	21.5	28.7	36.7	6.8%
Wind	0.2	0.2	0.7	0.7	0.9	1.1	1.5	7.7%
Total end-use sector capacity	**10.4**	**12.1**	**18.2**	**22.4**	**28.6**	**36.0**	**44.6**	**4.9%**
Generation (billion kilowatthours)								
Conventional hydroelectric power	1.4	1.4	1.4	1.4	1.4	1.4	1.4	0.0%
Geothermal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Municipal waste[8]	3.6	3.6	3.6	3.6	3.6	3.6	3.6	0.0%
Biomass	26.5	27.2	29.1	29.3	29.4	29.4	30.5	0.4%
Solar photovoltaic[5]	7.1	9.6	17.9	24.8	34.7	46.3	59.3	7.0%
Wind	0.2	0.3	0.9	1.0	1.2	1.5	2.1	8.0%
Total end-use sector generation	**38.8**	**42.1**	**52.9**	**60.1**	**70.2**	**82.3**	**96.9**	**3.1%**

Table A16. Renewable energy generating capacity and generation (continued)
(gigawatts, unless otherwise noted)

Net summer capacity and generation	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Total, all sectors								
Net summer capacity								
Conventional hydroelectric power	78.4	78.5	79.5	79.9	80.0	80.1	80.4	0.1%
Geothermal	2.6	2.6	3.8	5.3	7.0	8.2	9.1	4.7%
Municipal waste	4.1	4.1	4.3	4.3	4.3	4.3	4.3	0.1%
Wood and other biomass[4]	7.8	8.3	8.9	8.9	9.1	9.6	11.1	1.1%
Solar[5]	7.6	12.7	27.6	31.9	39.0	48.3	60.6	6.0%
Wind	59.4	60.5	82.7	83.6	87.3	96.7	109.7	2.2%
Total capacity, all sectors	**159.8**	**166.8**	**206.8**	**214.1**	**226.6**	**247.2**	**275.2**	**1.9%**
Generation (billion kilowatthours)								
Conventional hydroelectric power	275.2	267.1	292.3	294.2	294.7	295.2	297.0	0.4%
Geothermal	15.6	16.5	26.8	38.5	52.4	62.3	69.6	5.5%
Municipal waste	20.6	20.1	23.7	23.9	23.7	23.7	23.8	0.6%
Wood and other biomass	37.6	39.4	53.8	65.5	69.8	76.5	89.3	3.1%
Solar[5]	11.2	18.5	51.3	58.7	70.9	87.5	110.1	6.8%
Wind	141.0	167.8	231.5	234.9	244.6	277.8	319.3	2.4%
Total generation, all sectors	**501.2**	**529.5**	**679.4**	**715.6**	**756.2**	**823.0**	**909.1**	**2.0%**

[1]Includes electricity-only and combined heat and power plants that have a regulatory status.
[2]Includes both hydrothermal resources (hot water and steam) and near-field enhanced geothermal systems (EGS). Near-field EGS potential occurs on known hydrothermal sites, however this potential requires the addition of external fluids for electricity generation and is only available after 2025.
[3]Includes municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[4]Facilities co-firing biomass and coal are classified as coal.
[5]Does not include off-grid photovoltaics (PV). Based on annual PV shipments from 1989 through 2013, EIA estimates that as much as 274 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2013, plus an additional 573 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See U.S. Energy Information Administration, *Annual Energy Review 2011*, DOE/EIA-0384(2011) (Washington, DC, September 2012), Table 10.9 (annual PV shipments, 1989-2010), and Table 12 (U.S. photovoltaic module shipments by end use, sector, and type) in U.S. Energy Information Administration, *Solar Photovoltaic Cell/Module Shipments Report, 2011* (Washington, DC, September 2012) and U.S. Energy Information Administration, *Solar Photovoltaic Cell/Module Shipments Report, 2012* (Washington, DC, December 2013). The approach used to develop the estimate, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It will overestimate the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier will be retired from service or abandoned.
[6]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. Only biogenic municipal waste is included. The U.S. Energy Information Administration estimates that in 2013 approximately 7 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy* (Washington, DC, May 2007).
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors that have a non-regulatory status; and small on-site generating systems in the residential, commercial, and industrial sectors used primarily for own-use generation, but which may also sell some power to the grid.
[8]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 capacity: U.S. Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). 2012 and 2013 generation: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A17. Renewable energy consumption by sector and source
(quadrillion Btu per year)

Sector and source	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Marketed renewable energy[1]								
Residential (wood)	**0.44**	**0.58**	**0.41**	**0.39**	**0.38**	**0.36**	**0.35**	**-1.8%**
Commercial (biomass)	**0.11**	**0.12**	**0.12**	**0.12**	**0.12**	**0.12**	**0.12**	**0.0%**
Industrial[2]	**2.24**	**2.20**	**2.33**	**2.39**	**2.39**	**2.39**	**2.49**	**0.5%**
Conventional hydroelectric power	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.0%
Municipal waste[3]	0.17	0.19	0.19	0.19	0.19	0.19	0.19	0.2%
Biomass	1.32	1.28	1.33	1.39	1.39	1.38	1.42	0.4%
Biofuels heat and coproducts	0.73	0.72	0.80	0.80	0.80	0.81	0.86	0.6%
Transportation	**1.18**	**1.26**	**1.43**	**1.42**	**1.42**	**1.46**	**1.57**	**0.8%**
Ethanol used in E85[4]	0.01	0.01	0.02	0.08	0.13	0.16	0.19	9.9%
Ethanol used in gasoline blending	1.05	1.06	1.07	1.00	0.95	0.96	1.05	0.0%
Biodiesel used in distillate blending	0.11	0.19	0.27	0.21	0.21	0.21	0.21	0.4%
Biobutanol	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Liquids from biomass	0.00	0.00	0.01	0.02	0.02	0.02	0.02	22.0%
Renewable diesel and gasoline[5]	0.00	0.00	0.06	0.11	0.11	0.11	0.11	- -
Electric power[6]	**4.53**	**4.78**	**6.13**	**6.43**	**6.72**	**7.26**	**7.99**	**1.9%**
Conventional hydroelectric power	2.61	2.53	2.77	2.79	2.79	2.80	2.81	0.4%
Geothermal	0.15	0.16	0.26	0.37	0.50	0.60	0.67	5.5%
Biogenic municipal waste[7]	0.23	0.23	0.27	0.27	0.27	0.27	0.27	0.6%
Biomass	0.17	0.18	0.32	0.45	0.50	0.58	0.74	5.3%
Dedicated plants	0.10	0.12	0.14	0.16	0.18	0.21	0.32	3.8%
Cofiring	0.07	0.07	0.18	0.29	0.33	0.37	0.42	7.0%
Solar thermal	0.01	0.01	0.03	0.03	0.03	0.03	0.03	5.1%
Solar photovoltaic	0.03	0.08	0.28	0.29	0.31	0.36	0.45	6.8%
Wind	1.34	1.59	2.19	2.23	2.32	2.63	3.02	2.4%
Total marketed renewable energy	**8.50**	**8.95**	**10.42**	**10.76**	**11.04**	**11.60**	**12.52**	**1.3%**
Sources of ethanol								
from corn and other starch	1.08	1.09	1.10	1.09	1.10	1.11	1.19	0.3%
from cellulose	0.00	0.00	0.01	0.01	0.01	0.01	0.01	- -
Net imports	-0.02	-0.02	-0.03	-0.02	-0.03	-0.01	0.02	- -
Total	**1.06**	**1.07**	**1.09**	**1.08**	**1.08**	**1.12**	**1.23**	**0.5%**

Table A17. Renewable energy consumption by sector and source (continued)
(quadrillion Btu per year)

Sector and source	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Nonmarketed renewable energy[8]								
Selected consumption								
Residential	**0.04**	**0.06**	**0.13**	**0.17**	**0.23**	**0.28**	**0.35**	**7.0%**
Solar hot water heating	0.01	0.01	0.01	0.01	0.01	0.01	0.01	1.8%
Geothermal heat pumps	0.01	0.01	0.02	0.02	0.03	0.03	0.03	4.1%
Solar photovoltaic	0.02	0.04	0.09	0.13	0.18	0.24	0.29	8.0%
Wind	0.00	0.00	0.01	0.01	0.01	0.01	0.01	6.9%
Commercial	**0.13**	**0.14**	**0.17**	**0.20**	**0.25**	**0.32**	**0.39**	**3.9%**
Solar thermal	0.08	0.08	0.09	0.09	0.10	0.10	0.11	1.1%
Solar photovoltaic	0.04	0.05	0.08	0.11	0.15	0.20	0.27	6.1%
Wind	0.00	0.00	0.00	0.00	0.00	0.01	0.01	9.0%

[1]Includes nonelectric renewable energy groups for which the energy source is bought and sold in the marketplace, although all transactions may not necessarily *be marketed, and marketed renewable energy inputs for electricity entering the marketplace on the electric power grid. Excludes electricity imports; see Table A2.* Actual heat rates used to determine fuel consumption for all renewable fuels except hydroelectric, geothermal, solar, and wind. Consumption at hydroelectric, geothermal, solar, and wind facilities is determined by using the fossil fuel equivalent of 9,516 Btu per kilowatthour.
[2]*Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.*
[3]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[4]*Excludes motor gasoline component of E85.*
[5]Renewable feedstocks for the on-site production of diesel and gasoline.
[6]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[7]*Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. Only biogenic* municipal waste is included. The U.S. Energy Information Administration estimates that in 2013 approximately 0.3 quadrillion Btus were consumed from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy* (Washington, DC, May 2007).
[8]Includes selected renewable energy consumption data for which the energy is not bought or sold, either directly or indirectly as an input to marketed energy. The U.S. Energy Information Administration does not estimate or project total consumption of nonmarketed renewable energy.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 ethanol: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2012 and 2013 electric power sector: EIA, Form EIA-860, "Annual Electric Generator Report" (preliminary). Other 2012 and 2013 values: EIA, Office of Energy Analysis. **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A18. Energy-related carbon dioxide emissions by sector and source
(million metric tons, unless otherwise noted)

Sector and source	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Residential								
Petroleum	61	64	50	45	41	37	33	-2.4%
Natural gas	225	267	246	241	240	235	229	-0.6%
Electricity[1]	757	773	761	761	770	776	779	0.0%
Total residential	**1,044**	**1,105**	**1,057**	**1,047**	**1,051**	**1,048**	**1,042**	**-0.2%**
Commercial								
Petroleum	40	41	44	43	42	41	41	-0.1%
Natural gas	157	178	175	175	182	189	197	0.4%
Coal	4	4	5	5	5	5	4	0.5%
Electricity[1]	731	744	755	772	788	801	814	0.3%
Total commercial	**933**	**968**	**979**	**994**	**1,016**	**1,037**	**1,057**	**0.3%**
Industrial[2]								
Petroleum	345	350	410	425	424	424	429	0.8%
Natural gas[3]	447	462	512	523	539	549	563	0.7%
Coal	142	143	150	148	144	139	139	-0.1%
Electricity[1]	543	531	586	615	613	601	592	0.4%
Total industrial	**1,476**	**1,486**	**1,658**	**1,711**	**1,719**	**1,714**	**1,723**	**0.5%**
Transportation								
Petroleum[4]	1,774	1,792	1,752	1,701	1,662	1,647	1,631	-0.3%
Natural gas[5]	41	49	49	53	59	67	89	2.2%
Electricity[1]	4	4	5	5	6	8	9	2.9%
Total transportation	**1,819**	**1,845**	**1,806**	**1,759**	**1,727**	**1,722**	**1,728**	**-0.2%**
Electric power[6]								
Petroleum	19	23	13	13	13	13	13	-2.1%
Natural gas	493	442	412	441	478	497	509	0.5%
Coal	1,511	1,575	1,670	1,687	1,674	1,664	1,661	0.2%
Other[7]	12	12	12	12	12	12	12	0.0%
Total electric power	**2,035**	**2,053**	**2,107**	**2,153**	**2,177**	**2,186**	**2,195**	**0.2%**
Total by fuel								
Petroleum[4]	2,240	2,272	2,269	2,227	2,182	2,163	2,147	-0.2%
Natural gas	1,363	1,399	1,394	1,432	1,497	1,538	1,586	0.5%
Coal	1,657	1,722	1,824	1,840	1,822	1,808	1,804	0.2%
Other[7]	12	12	12	12	12	12	12	0.0%
Total	**5,272**	**5,405**	**5,499**	**5,511**	**5,514**	**5,521**	**5,549**	**0.1%**
Carbon dioxide emissions (tons per person)	**16.8**	**17.1**	**16.5**	**15.9**	**15.4**	**14.9**	**14.6**	**-0.6%**

[1]Emissions from the electric power sector are distributed to the end-use sectors.
[2]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[3]Includes lease and plant fuel.
[4]This includes carbon dioxide from international bunker fuels, both civilian and military, which are excluded from the accounting of carbon dioxide emissions under the United Nations convention. From 1990 through 2013, international bunker fuels accounted for 90 to 126 million metric tons annually.
[5]Includes pipeline fuel natural gas and natural gas used as fuel in motor vehicles, trains, and ships.
[6]Includes electricity-only and combined heat and power plants that have a regulatory status.
[7]Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.
Note: By convention, the direct emissions from biogenic energy sources are excluded from energy-related carbon dioxide emissions. The release of carbon from these sources is assumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net emissions over some period of time. If, however, increased use of biomass energy results in a decline in terrestrial carbon stocks, a net positive release of carbon may occur. See Table A19, "Energy-Related Carbon Dioxide Emissions by End Use", for the emissions from biogenic energy sources as an indication of the potential net release of carbon dioxide in the absence of offsetting sequestration. Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 emissions and emission factors: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A19. Energy-related carbon dioxide emissions by end use
(million metric tons)

Sector and end use	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Residential								
Space heating	228	293	248	236	228	218	207	-1.3%
Space cooling	136	109	124	128	135	141	145	1.1%
Water heating	143	144	142	142	143	139	134	-0.3%
Refrigeration	60	59	53	51	51	51	52	-0.5%
Cooking	30	30	31	32	32	33	34	0.4%
Clothes dryers	35	36	36	37	37	38	39	0.3%
Freezers	13	13	11	11	10	10	9	-1.1%
Lighting	103	96	67	59	52	43	38	-3.3%
Clothes washers[1]	5	5	4	3	3	2	2	-2.4%
Dishwashers[1]	16	15	15	15	17	17	18	0.5%
Televisions and related equipment[2]	54	54	50	50	51	53	54	0.0%
Computers and related equipment[3]	20	20	15	12	11	9	7	-3.6%
Furnace fans and boiler circulation pumps	15	21	18	17	16	14	13	-1.8%
Other uses[4]	188	211	242	253	267	278	288	1.2%
Discrepancy[5]	0	0	0	0	0	0	0	- -
Total residential	**1,044**	**1,105**	**1,057**	**1,047**	**1,051**	**1,048**	**1,042**	**-0.2%**
Commercial								
Space heating[6]	112	136	122	115	111	105	97	-1.2%
Space cooling[6]	95	82	85	84	84	83	82	0.0%
Water heating[6]	44	45	44	44	44	44	43	-0.2%
Ventilation	82	84	85	85	85	84	83	0.0%
Cooking	14	14	15	15	16	16	16	0.4%
Lighting	149	148	137	131	127	120	116	-0.9%
Refrigeration	61	61	52	48	46	45	45	-1.1%
Office equipment (PC)	19	17	11	8	6	4	3	-5.9%
Office equipment (non-PC)	35	35	38	42	47	51	55	1.6%
Other uses[7]	321	346	392	422	452	484	516	1.5%
Total commercial	**933**	**968**	**979**	**994**	**1,016**	**1,037**	**1,057**	**0.3%**
Industrial[8]								
Manufacturing								
Refining	261	268	252	251	250	255	260	-0.1%
Food products	96	96	104	109	113	116	119	0.8%
Paper products	69	69	63	59	54	50	49	-1.2%
Bulk chemicals	247	247	293	311	309	298	291	0.6%
Glass	15	15	16	16	17	16	16	0.1%
Cement and lime	29	30	41	42	45	48	52	2.1%
Iron and steel	125	123	135	141	135	129	122	0.0%
Aluminum	45	46	54	55	51	43	38	-0.7%
Fabricated metal products	38	39	42	43	42	43	43	0.3%
Machinery	22	22	24	25	27	28	29	1.1%
Computers and electronics	47	48	48	49	51	53	52	0.3%
Transportation equipment	44	47	50	52	53	58	63	1.1%
Electrical equipment	8	8	9	10	10	11	12	1.4%
Wood products	15	17	20	20	20	19	18	0.3%
Plastics	39	40	44	46	48	49	49	0.8%
Balance of manufacturing	154	156	161	164	165	166	169	0.3%
Total manufacturing	**1,254**	**1,270**	**1,355**	**1,392**	**1,389**	**1,383**	**1,383**	**0.3%**
Nonmanufacturing								
Agriculture	66	66	65	64	62	60	58	-0.4%
Construction	62	64	77	80	83	85	87	1.1%
Mining	101	102	117	115	113	108	108	0.2%
Total nonmanufacturing	**230**	**232**	**259**	**259**	**257**	**253**	**253**	**0.3%**
Discrepancy[5]	-8	-16	44	61	73	79	86	- -
Total industrial	**1,476**	**1,486**	**1,658**	**1,711**	**1,719**	**1,714**	**1,723**	**0.5%**

Table A19. Energy-related carbon dioxide emissions by end use (continued)
(million metric tons)

Sector and end use	Reference case 2012	2013	2020	2025	2030	2035	2040	Annual growth 2013-2040 (percent)
Transportation								
Light-duty vehicles	1,035	1,044	967	892	834	801	777	-1.1%
Commercial light trucks[9]	36	38	37	36	35	35	36	-0.2%
Bus transportation	16	18	18	18	19	19	19	0.2%
Freight trucks	356	389	417	429	440	456	477	0.8%
Rail, passenger	5	6	6	6	6	6	7	0.6%
Rail, freight	31	36	35	36	34	32	31	-0.5%
Shipping, domestic	7	7	7	6	6	5	5	-1.4%
Shipping, international	52	48	47	47	47	48	48	0.0%
Recreational boats	16	17	18	18	19	20	20	0.6%
Air	165	163	180	193	206	214	219	1.1%
Military use	50	48	45	45	48	51	54	0.5%
Lubricants	5	5	5	5	5	5	5	0.3%
Pipeline fuel	40	47	45	48	50	50	51	0.3%
Discrepancy[5]	5	-21	-21	-21	-21	-21	-20	- -
Total transportation	**1,819**	**1,845**	**1,806**	**1,759**	**1,727**	**1,722**	**1,728**	**-0.2%**
Biogenic energy combustion[10]								
Biomass	192	203	205	221	224	229	247	0.7%
Electric power sector	16	17	30	42	47	55	69	5.3%
Other sectors	176	186	175	179	177	174	178	-0.2%
Biogenic waste	21	21	24	25	24	24	24	0.6%
Biofuels heat and coproducts	69	68	75	75	75	76	81	0.6%
Ethanol	73	73	74	74	74	77	84	0.5%
Biodiesel	8	14	20	16	16	16	16	0.4%
Liquids from biomass	0	0	1	1	1	1	1	22.0%
Renewable diesel and gasoline	0	0	4	8	8	8	8	- -
Total	**362**	**379**	**403**	**419**	**422**	**431**	**461**	**0.7%**

[1]Does not include water heating portion of load.
[2]Includes televisions, set-top boxes, home theater systems, DVD players, and video game consoles.
[3]Includes desktop and laptop computers, monitors, and networking equipment.
[4]Includes small electric devices, heating elements, outdoor grills, exterior lights, pool heaters, spa heaters, backup electricity generators, and motors not listed above. Electric vehicles are included in the transportation sector.
[5]Represents differences between total emissions by end-use and total emissions by fuel as reported in Table A18. Emissions by fuel may reflect benchmarking and other modeling adjustments to energy use and the associated emissions that are not assigned to specific end uses.
[6]Includes emissions related to fuel consumption for district services.
[7]Includes emissions related to (but not limited to) miscellaneous uses such as transformers, medical imaging and other medical equipment, elevators, escalators, off-road electric vehicles, laboratory fume hoods, laundry equipment, coffee brewers, water services, pumps, emergency generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, propane, coal, motor gasoline, kerosene, and marketed renewable fuels (biomass).
[8]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[9]Commercial trucks 8,501 to 10,000 pounds gross vehicle weight rating.
[10]By convention, the direct emissions from biogenic energy sources are excluded from energy-related carbon dioxide emissions. The release of carbon from these sources is assumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net emissions over some period of time. If, however, increased use of biomass energy results in a decline in terrestrial carbon stocks, a net positive release of carbon may occur. Accordingly, the emissions from biogenic energy sources are reported here as an indication of the potential net release of carbon dioxide in the absence of offsetting sequestration.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 emissions and emission factors: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). **Projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A20. Macroeconomic indicators
(billion 2009 chain-weighted dollars, unless otherwise noted)

Indicators	Reference case 2012	2013	2020	2025	2030	2035	2040	Annual growth 2013-2040 (percent)
Real gross domestic product	**15,369**	**15,710**	**18,801**	**21,295**	**23,894**	**26,659**	**29,898**	**2.4%**
Components of real gross domestic product								
Real consumption	10,450	10,700	12,832	14,484	16,275	18,179	20,476	2.4%
Real investment	2,436	2,556	3,531	4,025	4,474	4,984	5,634	3.0%
Real government spending	2,954	2,894	2,985	3,098	3,286	3,469	3,691	0.9%
Real exports	1,960	2,020	2,813	3,807	4,815	6,010	7,338	4.9%
Real imports	2,413	2,440	3,334	4,079	4,888	5,859	7,037	4.0%
Energy intensity (thousand Btu per 2009 dollar of GDP)								
Delivered energy	4.47	4.53	3.93	3.49	3.13	2.83	2.56	-2.1%
Total energy	6.14	6.18	5.36	4.79	4.31	3.90	3.54	-2.0%
Price indices								
GDP chain-type price index (2009=1.000)	1.05	1.07	1.21	1.31	1.43	1.57	1.73	1.8%
Consumer price index (1982-4=1.00)								
All-urban	2.30	2.33	2.63	2.89	3.18	3.54	3.95	2.0%
Energy commodities and services	2.46	2.44	2.55	2.98	3.42	4.03	4.85	2.6%
Wholesale price index (1982=1.00)								
All commodities	2.02	2.03	2.25	2.47	2.71	3.02	3.39	1.9%
Fuel and power	2.12	2.12	2.26	2.67	3.08	3.69	4.56	2.9%
Metals and metal products	2.20	2.14	2.43	2.62	2.85	3.13	3.42	1.8%
Industrial commodities excluding energy	1.94	1.96	2.22	2.40	2.61	2.85	3.12	1.7%
Interest rates (percent, nominal)								
Federal funds rate	0.14	0.11	3.40	3.56	3.69	3.76	4.04	- -
10-year treasury note	1.80	2.35	4.12	4.14	4.28	4.41	4.63	- -
AA utility bond rate	3.83	4.24	6.15	6.06	6.33	6.47	6.71	- -
Value of shipments (billion 2009 dollars)								
Non-industrial and service sectors	23,989	24,398	28,468	32,023	34,968	37,767	40,814	1.9%
Total industrial	6,822	7,004	8,467	9,212	9,870	10,614	11,463	1.8%
Agriculture, mining, and construction	1,813	1,858	2,344	2,441	2,540	2,601	2,712	1.4%
Manufacturing	5,009	5,146	6,123	6,771	7,330	8,012	8,751	2.0%
Energy-intensive	1,675	1,685	1,946	2,084	2,168	2,237	2,317	1.2%
Non-energy-intensive	3,334	3,461	4,177	4,687	5,162	5,776	6,433	2.3%
Total shipments	**30,810**	**31,402**	**36,935**	**41,235**	**44,838**	**48,380**	**52,277**	**1.9%**
Population and employment (millions)								
Population, with armed forces overseas	315	317	334	347	359	370	380	0.7%
Population, aged 16 and over	249	251	267	277	288	298	307	0.7%
Population, aged 65 and over	43	45	56	65	73	78	80	2.2%
Employment, nonfarm	134	136	149	154	159	163	169	0.8%
Employment, manufacturing	11.8	11.9	11.8	11.3	10.7	10.3	9.7	-0.7%
Key labor indicators								
Labor force (millions)	155	155	166	170	174	179	185	0.6%
Nonfarm labor productivity (2009=1.00)	1.05	1.05	1.20	1.34	1.48	1.62	1.78	2.0%
Unemployment rate (percent)	8.08	7.35	5.40	4.96	5.03	5.02	4.85	- -
Key indicators for energy demand								
Real disposable personal income	11,676	11,651	14,411	16,318	18,487	20,610	22,957	2.5%
Housing starts (millions)	0.84	0.99	1.69	1.70	1.66	1.62	1.62	1.8%
Commercial floorspace (billion square feet)	82.3	82.8	89.0	94.1	98.4	103.2	109.1	1.0%
Unit sales of light-duty vehicles (millions)	14.4	15.5	17.0	17.2	17.5	17.7	18.2	0.6%

GDP = Gross domestic product.
Btu = British thermal unit.
- - = Not applicable.
Sources: *2012 and 2013: IHS Economics, Industry and Employment models, November 2014.* **Projections:** *U.S. Energy Information Administration,* AEO2015 National Energy Modeling System run REF2015.D021915A.

Table A21. International petroleum and other liquids supply, disposition, and prices
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Crude oil spot prices								
(2013 dollars per barrel)								
Brent	113	109	79	91	106	122	141	1.0%
West Texas Intermediate	96	98	73	85	99	116	136	1.2%
(nominal dollars per barrel)								
Brent	112	109	90	112	142	180	229	2.8%
West Texas Intermediate	94	98	83	105	133	171	220	3.0%
Petroleum and other liquids consumption[1]								
OECD								
United States (50 states)	18.47	18.96	19.65	19.61	19.41	19.29	19.27	0.1%
United States territories	0.29	0.30	0.31	0.32	0.34	0.36	0.38	1.0%
Canada	2.29	2.29	2.31	2.25	2.21	2.17	2.14	-0.3%
Mexico and Chile	2.50	2.46	2.71	2.78	2.80	2.83	2.92	0.6%
OECD Europe[2]	14.07	13.96	14.20	14.15	14.09	14.03	14.12	0.0%
Japan	4.73	4.56	4.27	4.18	4.03	3.86	3.65	-0.8%
South Korea	2.41	2.43	2.58	2.57	2.53	2.46	2.40	0.0%
Australia and New Zealand	1.17	1.16	1.16	1.12	1.11	1.11	1.15	-0.1%
Total OECD consumption	**45.93**	**46.14**	**47.20**	**46.97**	**46.52**	**46.10**	**46.04**	**0.0%**
Non-OECD								
Russia	3.20	3.30	3.31	3.24	3.23	3.17	3.01	-0.3%
Other Europe and Eurasia[3]	2.00	2.06	2.22	2.28	2.39	2.50	2.59	0.9%
China	10.29	10.67	13.13	14.75	17.03	18.92	20.19	2.4%
India	3.63	3.70	4.30	4.89	5.52	6.13	6.79	2.3%
Other Asia[4]	7.35	7.37	9.08	10.69	12.35	14.20	16.49	3.0%
Middle East	7.32	7.61	8.40	8.81	9.56	10.28	11.13	1.4%
Africa	3.36	3.42	3.93	4.28	4.78	5.39	6.18	2.2%
Brazil	2.93	3.11	3.33	3.44	3.74	4.09	4.50	1.4%
Other Central and South America	3.35	3.38	3.49	3.55	3.72	3.90	4.15	0.8%
Total non-OECD consumption	**43.41**	**44.60**	**51.20**	**55.92**	**62.31**	**68.58**	**75.01**	**1.9%**
Total consumption	**89.3**	**90.7**	**98.4**	**102.9**	**108.8**	**114.7**	**121.0**	**1.1%**
Petroleum and other liquids production								
OPEC[5]								
Middle East	26.29	26.32	24.56	26.23	29.34	33.12	36.14	1.2%
North Africa	3.37	2.90	3.51	3.56	3.67	3.85	4.06	1.3%
West Africa	4.40	4.26	5.00	5.16	5.24	5.33	5.43	0.9%
South America	2.99	3.01	3.10	3.16	3.27	3.49	3.79	0.9%
Total OPEC production	**37.05**	**36.49**	**36.16**	**38.10**	**41.53**	**45.79**	**49.42**	**1.1%**
Non-OPEC								
OECD								
United States (50 states)	11.04	12.64	16.92	16.74	16.52	15.84	15.89	0.8%
Canada	4.00	4.15	5.05	5.68	6.26	6.61	6.76	1.8%
Mexico and Chile	2.96	2.94	2.93	3.12	3.32	3.52	3.79	0.9%
OECD Europe[2]	4.04	3.88	3.35	3.06	2.98	2.97	3.19	-0.7%
Japan and South Korea	0.18	0.18	0.17	0.17	0.18	0.18	0.18	0.1%
Australia and New Zealand	0.57	0.49	0.60	0.80	0.86	0.91	0.96	2.5%
Total OECD production	**22.80**	**24.29**	**29.03**	**29.58**	**30.12**	**30.03**	**30.77**	**0.9%**
Non-OECD								
Russia	10.52	10.50	10.71	10.78	11.22	11.81	12.16	0.5%
Other Europe and Eurasia[3]	3.20	3.27	3.41	4.14	4.42	4.70	5.18	1.7%
China	4.39	4.48	5.11	5.46	5.66	5.75	5.84	1.0%
Other Asia[4]	3.88	3.82	3.85	3.72	3.67	3.71	4.01	0.2%
Middle East	1.31	1.20	1.03	0.93	0.85	0.78	0.77	-1.6%
Africa	2.31	2.41	2.70	2.86	2.94	3.03	3.33	1.2%
Brazil	2.61	2.73	3.70	4.56	5.43	5.90	6.12	3.0%
Other Central and South America	2.17	2.21	2.71	2.76	2.97	3.16	3.47	1.7%
Total non-OECD production	**30.38**	**30.63**	**33.21**	**35.22**	**37.17**	**38.85**	**40.88**	**1.1%**
Total petroleum and other liquids production	**90.2**	**91.4**	**98.4**	**102.9**	**108.8**	**114.7**	**121.1**	**1.0%**
OPEC market share (percent)	41.1	39.9	36.7	37.0	38.2	39.9	40.8	- -

Table A21. International petroleum and other liquids supply, disposition, and prices (continued)
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	Reference case							Annual growth 2013-2040 (percent)
	2012	2013	2020	2025	2030	2035	2040	
Selected world production subtotals:								
Crude oil and equivalents[6]	77.35	77.93	82.19	85.20	89.77	94.33	99.09	0.9%
Tight oil	2.63	3.62	7.49	8.31	9.16	9.82	10.15	3.9%
Bitumen[7]	1.94	2.11	3.00	3.52	3.95	4.21	4.26	2.6%
Refinery processing gain[8]	2.37	2.40	2.42	2.61	2.74	2.88	2.97	0.8%
Natural gas plant liquids	9.11	9.36	11.28	11.93	12.42	12.93	13.79	1.4%
Liquids from renewable sources[9]	1.93	2.14	2.56	2.92	3.36	3.78	4.22	2.5%
Liquids from coal[10]	0.21	0.21	0.33	0.51	0.69	0.87	1.05	6.2%
Liquids from natural gas[11]	0.14	0.24	0.33	0.43	0.51	0.57	0.61	3.5%
Liquids from kerogen[12]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.7%
Crude oil production[6]								
OPEC[5]								
Middle East	23.24	23.13	21.20	22.66	25.59	29.11	31.79	1.2%
North Africa	2.91	2.43	2.93	2.93	2.92	2.93	2.96	0.7%
West Africa	4.34	4.20	4.89	5.05	5.13	5.21	5.29	0.9%
South America	2.80	2.82	2.86	2.86	2.98	3.20	3.48	0.8%
Total OPEC production	**33.30**	**32.60**	**31.89**	**33.51**	**36.62**	**40.46**	**43.52**	**1.1%**
Non-OPEC								
OECD								
United States (50 states)	7.54	8.90	11.58	11.28	11.01	10.37	10.41	0.6%
Canada	3.28	3.42	4.35	4.93	5.48	5.83	5.92	2.0%
Mexico and Chile	2.61	2.59	2.61	2.81	3.00	3.22	3.45	1.1%
OECD Europe[2]	2.99	2.82	2.17	1.80	1.66	1.58	1.69	-1.9%
Japan and South Korea	0.01	0.00	0.00	0.00	0.00	0.00	0.00	-1.6%
Australia and New Zealand	0.45	0.37	0.47	0.61	0.67	0.71	0.75	2.7%
Total OECD production	**16.87**	**18.10**	**21.18**	**21.44**	**21.83**	**21.71**	**22.23**	**0.8%**
Non-OECD								
Russia	10.04	10.02	10.15	10.11	10.42	10.85	11.10	0.4%
Other Europe and Eurasia[3]	*2.95*	*3.05*	*3.18*	*3.83*	*4.03*	*4.21*	*4.66*	*1.6%*
China	4.07	4.16	4.54	4.68	4.56	4.36	4.13	0.0%
Other Asia[4]	3.14	3.04	2.94	2.63	2.45	2.38	2.47	-0.8%
Middle East	1.26	1.16	1.00	0.90	0.82	0.76	0.74	-1.6%
Africa	1.88	1.97	2.18	2.31	2.38	2.45	2.70	1.2%
Brazil	2.06	2.02	2.87	3.50	4.16	4.47	4.60	3.1%
Other Central and South America	1.77	1.81	2.25	2.29	2.49	2.67	2.94	1.8%
Total non-OECD production	**27.18**	**27.24**	**29.11**	**30.25**	**31.32**	**32.15**	**33.35**	**0.8%**
Total crude oil production[6]	**77.3**	**77.9**	**82.2**	**85.2**	**89.8**	**94.3**	**99.1**	**0.9%**
OPEC market share (percent)	43.1	41.8	38.8	39.3	40.8	42.9	43.9	- -

[1]Estimated consumption. Includes both OPEC and non-OPEC consumers in the regional breakdown.
[2]OECD Europe = Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.
[3]Other Europe and Eurasia = Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Georgia, Kazakhstan, Kosovo, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Serbia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.
[4]Other Asia = Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), Fiji, French Polynesia, Guam, Hong Kong, India (for production), Indonesia, Kiribati, Laos, Malaysia, Macau, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, and Vietnam.
[5]OPEC = Organization of the Petroleum Exporting Countries = Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[6]Includes crude oil, lease condensate, tight oil (shale oil), extra-heavy oil, and bitumen (oil sands).
[7]Includes diluted and upgraded/synthetic bitumen (syncrude).
[8]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[9]*Includes liquids produced from energy crops.*
[10]Includes liquids converted from coal via the Fischer-Tropsch coal-to-liquids process.
[11]Includes liquids converted from natural gas via the Fischer-Tropsch gas-to-liquids process.
[12]Includes liquids produced from kerogen (oil shale, not to be confused with tight oil (shale oil)).
OECD = Organization for Economic Cooperation and Development.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2012 and 2013 are model results and may differ from official EIA data reports.
Sources: 2012 and 2013 Brent and West Texas Intermediate crude oil spot prices: Thomson Reuters. 2012 quantities derived from: Energy Information Administration (EIA), International Energy Statistics database as of September 2014. **2013 quantities and projections:** EIA, AEO2015 National Energy Modeling System run REF2015.D021915A and EIA, Generate World Oil Balance application.

Appendix B

Economic growth case comparisons

Table B1. Total energy supply, disposition, and price summary
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2013	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Production										
Crude oil and lease condensate	15.6	22.2	22.2	22.2	20.8	21.1	21.3	19.4	19.9	20.3
Natural gas plant liquids	3.6	5.4	5.5	5.5	5.6	5.7	5.8	5.4	5.5	5.7
Dry natural gas	25.1	29.2	29.6	30.0	32.6	33.9	35.3	35.5	36.4	37.7
Coal[1]	20.0	20.8	21.7	22.0	21.8	22.5	23.0	21.7	22.6	23.5
Nuclear / uranium[2]	8.3	8.4	8.4	8.4	8.5	8.5	8.6	8.5	8.7	9.5
Conventional hydroelectric power	2.5	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Biomass[3]	4.2	4.5	4.4	4.5	4.4	4.6	5.0	4.5	5.0	6.0
Other renewable energy[4]	2.3	3.2	3.2	3.4	3.5	3.6	4.2	3.7	4.6	6.7
Other[5]	1.3	0.8	0.9	0.9	0.9	0.9	1.0	0.9	1.0	1.0
Total	**82.7**	**97.4**	**98.7**	**99.7**	**100.7**	**103.7**	**107.0**	**102.3**	**106.6**	**113.3**
Imports										
Crude oil	17.0	12.8	13.6	14.3	13.9	15.7	17.3	15.6	18.2	20.7
Petroleum and other liquids[6]	4.3	4.5	4.6	4.6	4.3	4.4	4.5	4.0	4.1	4.6
Natural gas[7]	2.9	1.8	1.9	2.0	1.4	1.6	1.7	1.6	1.7	1.9
Other imports[8]	0.3	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	**24.5**	**19.3**	**20.2**	**21.0**	**19.7**	**21.7**	**23.5**	**21.3**	**24.1**	**27.3**
Exports										
Petroleum and other liquids[9]	7.3	11.1	11.2	11.1	12.7	12.6	12.6	13.7	13.7	13.7
Natural gas[10]	1.6	4.5	4.5	4.1	6.8	6.4	5.9	8.1	7.4	6.7
Coal	2.9	2.5	2.5	2.5	3.3	3.3	3.3	3.5	3.5	3.5
Total	**11.7**	**18.1**	**18.1**	**17.7**	**22.8**	**22.4**	**21.7**	**25.3**	**24.6**	**23.9**
Discrepancy[11]	**-1.6**	**-0.1**	**-0.1**	**-0.1**	**0.1**	**0.2**	**0.2**	**0.3**	**0.3**	**0.4**
Consumption										
Petroleum and other liquids[12]	35.9	36.2	37.1	37.9	34.1	36.5	38.5	32.9	36.2	39.8
Natural gas	26.9	26.4	26.8	27.7	27.0	28.8	30.9	28.6	30.5	32.7
Coal[13]	18.0	18.3	19.2	19.5	18.4	19.2	19.6	18.1	19.0	19.9
Nuclear / uranium[2]	8.3	8.4	8.4	8.4	8.5	8.5	8.6	8.5	8.7	9.5
Conventional hydroelectric power	2.5	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Biomass[14]	2.9	3.0	3.0	3.1	2.9	3.2	3.6	3.1	3.5	4.4
Other renewable energy[4]	2.3	3.2	3.2	3.4	3.5	3.6	4.2	3.7	4.6	6.7
Other[15]	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4
Total	**97.1**	**98.7**	**100.8**	**103.1**	**97.5**	**102.9**	**108.5**	**98.0**	**105.7**	**116.2**
Prices (2013 dollars per unit)										
Crude oil spot prices (dollars per barrel)										
Brent	109	78	79	80	104	106	108	138	141	145
West Texas Intermediate	98	72	73	74	97	99	102	132	136	140
Natural gas at Henry Hub (dollars per million Btu)	3.73	4.53	4.88	5.03	5.43	5.69	6.02	7.46	7.85	8.45
Coal (dollars per ton) at the minemouth[16]	37.2	37.5	37.9	38.0	43.6	43.7	44.1	49.0	49.2	50.3
Coal (dollars per million Btu) at the minemouth[16]	1.84	1.86	1.88	1.89	2.17	2.18	2.20	2.43	2.44	2.49
Average end-use[17]	2.50	2.50	2.54	2.56	2.81	2.84	2.88	3.06	3.09	3.18
Average electricity (cents per kilowatthour)	10.1	10.3	10.5	10.6	10.7	11.1	11.1	11.4	11.8	12.3

Table B1. Total energy supply, disposition, and price summary (continued)

(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2013	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Prices (nominal dollars per unit)										
Crude oil spot prices (dollars per barrel)										
Brent	109	95	90	90	178	142	139	345	229	224
West Texas Intermediate	98	87	83	83	168	133	132	331	220	216
Natural gas at Henry Hub (dollars per million Btu)	3.73	5.47	5.54	5.68	9.36	7.63	7.77	18.71	12.73	13.03
Coal (dollars per ton) at the minemouth[16]	37.2	45.2	43.0	42.8	75.0	58.6	57.0	122.9	79.8	77.6
Coal (dollars per million Btu)										
at the minemouth[16]	1.84	2.25	2.14	2.13	3.73	2.92	2.84	6.09	3.96	3.85
Average end-use[17]	2.50	3.02	2.88	2.89	4.84	3.81	3.71	7.67	5.00	4.90
Average electricity (cents per kilowatthour)	10.1	12.4	11.9	11.9	18.4	14.8	14.4	28.6	19.2	18.9

[1]Includes waste coal.
[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[3]Includes grid-connected electricity from wood and wood waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[4]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed *residential and commercial renewable energy data.*
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes imports of liquefied natural gas that are later re-exported.
[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.
[9]Includes crude oil, petroleum products, ethanol, and biodiesel.
[10]Includes re-exported liquefied natural gas.
[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[12]Estimated consumption. Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are hydrocarbon gas liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[13]*Excludes coal converted to coal-based synthetic liquids and natural gas.*
[14]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[16]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[17]Prices weighted by consumption; weighted average excludes export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 natural gas supply values: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). 2013 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2013*, DOE/EIA-0584(2013) (Washington, DC, January 2015). 2013 petroleum supply values: EIA, *Petroleum Supply Annual 2013*, DOE/EIA-0340(2013)/1 (Washington, DC, September 2014). 2013 crude oil spot prices and natural gas spot price at Henry Hub: Thomson Reuters. *Other 2013 coal values: Quarterly Coal Report, October-December 2013, DOE/EIA-0121(2013/4Q) (Washington, DC, March 2014). Other 2013 values:* EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). **Projections:** EIA, AEO2015 National Energy Modeling System runs LOWMACRO.D021915A, REF2015.D021915A, and HIGHMACRO.D021915A.

Table B2. Energy consumption by sector and source
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2013	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Energy consumption										
Residential										
Propane	0.43	0.32	0.32	0.33	0.27	0.28	0.30	0.23	0.25	0.28
Kerosene	0.01	0.01	0.01	0.01	0.00	0.01	0.01	0.00	0.00	0.00
Distillate fuel oil	0.50	0.40	0.40	0.40	0.31	0.31	0.31	0.24	0.24	0.24
Petroleum and other liquids subtotal	0.93	0.73	0.73	0.74	0.58	0.59	0.62	0.47	0.49	0.53
Natural gas	5.05	4.59	4.63	4.70	4.32	4.52	4.76	3.98	4.31	4.67
Renewable energy[1]	0.58	0.41	0.41	0.42	0.36	0.38	0.39	0.34	0.35	0.37
Electricity	4.75	4.77	4.86	5.00	4.82	5.08	5.50	4.96	5.42	6.07
Delivered energy	**11.32**	**10.50**	**10.63**	**10.85**	**10.09**	**10.57**	**11.26**	**9.74**	**10.57**	**11.64**
Electricity related losses	9.79	9.57	9.75	9.97	9.56	9.91	10.52	9.60	10.33	11.51
Total	**21.10**	**20.07**	**20.38**	**20.82**	**19.66**	**20.48**	**21.78**	**19.35**	**20.91**	**23.15**
Commercial										
Propane	0.15	0.16	0.16	0.16	0.17	0.17	0.17	0.18	0.18	0.18
Motor gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06	0.06
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distillate fuel oil	0.37	0.34	0.34	0.34	0.31	0.30	0.30	0.27	0.27	0.27
Residual fuel oil	0.03	0.07	0.07	0.07	0.07	0.07	0.07	0.06	0.06	0.07
Petroleum and other liquids subtotal	0.59	0.62	0.62	0.62	0.60	0.60	0.60	0.57	0.58	0.59
Natural gas	3.37	3.32	3.30	3.29	3.38	3.43	3.45	3.62	3.71	3.75
Coal	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable energy[3]	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Electricity	4.57	4.82	4.82	4.83	5.17	5.19	5.27	5.59	5.66	5.77
Delivered energy	**8.69**	**8.92**	**8.90**	**8.91**	**9.31**	**9.38**	**9.48**	**9.95**	**10.12**	**10.27**
Electricity related losses	9.42	9.66	9.68	9.64	10.24	10.13	10.07	10.83	10.80	10.93
Total	**18.10**	**18.58**	**18.58**	**18.55**	**19.55**	**19.52**	**19.56**	**20.78**	**20.92**	**21.20**
Industrial[4]										
Liquefied petroleum gases and other[5]	2.51	3.13	3.20	3.23	3.51	3.72	3.81	3.60	3.67	3.76
Motor gasoline[2]	0.25	0.25	0.26	0.27	0.24	0.25	0.27	0.23	0.25	0.26
Distillate fuel oil	1.31	1.33	1.42	1.46	1.24	1.36	1.49	1.21	1.35	1.51
Residual fuel oil	0.06	0.11	0.10	0.13	0.12	0.13	0.14	0.11	0.13	0.15
Petrochemical feedstocks	0.74	0.94	0.95	0.98	1.07	1.14	1.17	1.16	1.20	1.23
Other petroleum[6]	3.52	3.53	3.67	3.90	3.42	3.83	4.20	3.44	3.99	4.56
Petroleum and other liquids subtotal	8.40	9.30	9.61	9.96	9.59	10.44	11.08	9.76	10.59	11.48
Natural gas	7.62	8.04	8.33	8.46	8.04	8.65	9.17	8.13	8.90	9.83
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[7]	1.52	1.85	1.87	1.85	2.09	2.10	2.12	2.29	2.29	2.33
Natural gas subtotal	9.14	9.89	10.20	10.31	10.12	10.75	11.29	10.42	11.19	12.15
Metallurgical coal	0.62	0.55	0.61	0.65	0.49	0.56	0.66	0.43	0.51	0.69
Other industrial coal	0.88	0.89	0.93	1.00	0.87	0.96	1.09	0.87	0.99	1.25
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net coal coke imports	-0.02	0.00	0.00	0.01	-0.03	-0.03	-0.03	-0.05	-0.06	-0.07
Coal subtotal	1.48	1.44	1.54	1.65	1.33	1.48	1.72	1.25	1.44	1.86
Biofuels heat and coproducts	0.72	0.80	0.80	0.81	0.80	0.80	0.81	0.80	0.86	0.89
Renewable energy[8]	1.48	1.47	1.53	1.64	1.37	1.59	1.87	1.34	1.63	2.23
Electricity	3.26	3.58	3.74	3.99	3.58	4.04	4.49	3.60	4.12	4.88
Delivered energy	**24.48**	**26.48**	**27.42**	**28.35**	**26.80**	**29.10**	**31.27**	**27.17**	**29.82**	**33.50**
Electricity related losses	6.72	7.17	7.51	7.95	7.11	7.88	8.59	6.96	7.85	9.26
Total	**31.20**	**33.65**	**34.93**	**36.30**	**33.91**	**36.98**	**39.86**	**34.13**	**37.68**	**42.76**

Table B2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2013	Projections 2020 Low economic growth	2020 Reference	2020 High economic growth	2030 Low economic growth	2030 Reference	2030 High economic growth	2040 Low economic growth	2040 Reference	2040 High economic growth
Transportation										
Propane	0.05	0.04	0.04	0.04	0.05	0.05	0.06	0.06	0.07	0.08
Motor gasoline[2]	15.94	15.26	15.35	15.42	12.75	13.30	13.57	11.28	12.55	13.19
of which: E85[9]	*0.02*	*0.03*	*0.03*	*0.03*	*0.26*	*0.20*	*0.19*	*0.29*	*0.28*	*0.30*
Jet fuel[10]	2.80	2.95	3.01	3.07	3.27	3.40	3.54	3.51	3.64	3.79
Distillate fuel oil[11]	6.50	6.91	7.35	7.77	6.93	7.76	8.79	6.88	7.97	10.01
Residual fuel oil	0.57	0.35	0.35	0.35	0.36	0.36	0.36	0.36	0.36	0.37
Other petroleum[12]	0.15	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Petroleum and other liquids subtotal	26.00	25.68	26.27	26.82	23.52	25.03	26.48	22.25	24.76	27.61
Pipeline fuel natural gas	0.88	0.84	0.85	0.87	0.91	0.94	0.98	0.93	0.96	1.00
Compressed / liquefied natural gas	0.05	0.06	0.07	0.06	0.16	0.17	0.16	0.68	0.71	0.89
Liquid hydrogen	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*
Electricity	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.06	0.06	0.06
Delivered energy	**26.96**	**26.61**	**27.22**	**27.79**	**24.63**	**26.18**	**27.67**	**23.93**	**26.49**	**29.57**
Electricity related losses	0.05	0.06	0.06	0.06	0.08	0.08	0.08	0.11	0.12	0.12
Total	**27.01**	**26.67**	**27.29**	**27.85**	**24.71**	**26.27**	**27.75**	**24.04**	**26.61**	**29.69**
Unspecified sector[13]	**-0.27**	**-0.30**	**-0.34**	**-0.37**	**-0.31**	**-0.37**	**-0.45**	**-0.30**	**-0.38**	**-0.55**
Delivered energy consumption for all sectors										
Liquefied petroleum gases and other[5]	3.14	3.66	3.73	3.76	4.00	4.23	4.35	4.06	4.17	4.31
Motor gasoline[2]	*16.36*	*15.69*	*15.79*	*15.86*	*13.15*	*13.72*	*14.00*	*11.66*	*12.96*	*13.62*
of which: E85[9]	0.02	0.03	0.03	0.03	0.26	0.20	0.19	0.29	0.28	0.30
Jet fuel[10]	2.97	3.13	3.20	3.26	3.47	3.61	3.75	3.73	3.86	4.03
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	8.10	8.37	8.86	9.28	8.17	9.05	10.11	7.99	9.13	11.15
Residual fuel oil	0.65	0.53	0.53	0.55	0.54	0.56	0.57	0.54	0.56	0.58
Petrochemical feedstocks	0.74	0.94	0.95	0.98	1.07	1.14	1.17	1.16	1.20	1.23
Other petroleum[14]	3.67	3.68	3.82	4.06	3.57	3.98	4.36	3.59	4.15	4.72
Petroleum and other liquids subtotal	35.65	36.02	36.89	37.77	33.98	36.30	38.33	32.75	36.03	39.65
Natural gas	16.10	16.01	16.32	16.51	15.89	16.76	17.54	16.42	17.64	19.14
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[7]	1.52	1.85	1.87	1.85	2.09	2.10	2.12	2.29	2.29	2.33
Pipeline natural gas	0.88	0.84	0.85	0.87	0.91	0.94	0.98	0.93	0.96	1.00
Natural gas subtotal	18.50	18.70	19.05	19.23	18.89	19.80	20.64	19.64	20.88	22.47
Metallurgical coal	0.62	0.55	0.61	0.65	0.49	0.56	0.66	0.43	0.51	0.69
Other coal	0.92	0.94	0.98	1.04	0.91	1.00	1.14	0.92	1.04	1.30
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net coal coke imports	-0.02	0.00	0.00	0.01	-0.03	-0.03	-0.03	-0.05	-0.06	-0.07
Coal subtotal	1.52	1.49	1.59	1.69	1.38	1.53	1.77	1.30	1.49	1.91
Biofuels heat and coproducts	*0.72*	*0.80*	*0.80*	*0.81*	*0.80*	*0.80*	*0.81*	*0.80*	*0.86*	*0.89*
Renewable energy[15]	2.18	2.00	2.06	2.17	1.85	2.09	2.38	1.80	2.10	2.72
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	*12.60*	*13.20*	*13.45*	*13.85*	*13.61*	*14.35*	*15.30*	*14.20*	*15.25*	*16.78*
Delivered energy	**71.17**	**72.21**	**73.84**	**75.52**	**70.52**	**74.87**	**79.23**	**70.49**	**76.62**	**84.44**
Electricity related losses	25.97	26.45	27.00	27.62	26.99	28.01	29.27	27.51	29.10	31.81
Total	**97.14**	**98.67**	**100.84**	**103.15**	**97.52**	**102.87**	**108.50**	**97.99**	**105.73**	**116.25**
Electric power[16]										
Distillate fuel oil	0.05	0.09	0.09	0.09	0.08	0.08	0.09	0.08	0.08	0.08
Residual fuel oil	0.21	0.08	0.08	0.09	0.08	0.09	0.09	0.09	0.09	0.10
Petroleum and other liquids subtotal	*0.26*	*0.17*	*0.17*	*0.18*	*0.17*	*0.17*	*0.18*	*0.17*	*0.18*	*0.18*
Natural gas	8.36	7.66	7.80	8.42	8.14	9.03	10.24	8.97	9.61	10.23
Steam coal	16.49	16.84	17.59	17.85	17.00	17.63	17.85	16.81	17.52	17.95
Nuclear / uranium[17]	8.27	8.42	8.42	8.42	8.46	8.47	8.57	8.46	8.73	9.54
Renewable energy[18]	4.78	6.23	6.13	6.26	6.53	6.72	7.41	6.97	7.99	10.33
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Electricity imports	0.18	0.11	0.11	0.11	0.09	0.10	0.10	0.11	0.11	0.13
Total	**38.57**	**39.65**	**40.45**	**41.47**	**40.61**	**42.35**	**44.57**	**41.71**	**44.36**	**48.59**

Table B2. Energy consumption by sector and source (continued)

(quadrillion Btu per year, unless otherwise noted)

Sector and source	2013	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Total energy consumption										
Liquefied petroleum gases and other[5]	3.14	3.66	3.73	3.76	4.00	4.23	4.35	4.06	4.17	4.31
Motor gasoline[2]	16.36	15.69	15.79	15.86	13.15	13.72	14.00	11.66	12.96	13.62
of which: E85[9]	0.02	0.03	0.03	0.03	0.26	0.20	0.19	0.29	0.28	0.30
Jet fuel[10]	2.97	3.13	3.20	3.26	3.47	3.61	3.75	3.73	3.86	4.03
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	8.15	8.46	8.95	9.37	8.25	9.13	10.20	8.07	9.21	11.23
Residual fuel oil	0.87	0.62	0.61	0.64	0.63	0.64	0.66	0.63	0.65	0.68
Petrochemical feedstocks	0.74	0.94	0.95	0.98	1.07	1.14	1.17	1.16	1.20	1.23
Other petroleum[14]	3.67	3.68	3.82	4.06	3.57	3.98	4.36	3.59	4.15	4.72
Petroleum and other liquids subtotal	35.91	36.19	37.06	37.95	34.15	36.47	38.50	32.92	36.21	39.84
Natural gas	24.46	23.67	24.12	24.93	24.03	25.79	27.77	25.39	27.25	29.37
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[7]	1.52	1.85	1.87	1.85	2.09	2.10	2.12	2.29	2.29	2.33
Pipeline natural gas	0.88	0.84	0.85	0.87	0.91	0.94	0.98	0.93	0.96	1.00
Natural gas subtotal	26.86	26.36	26.85	27.65	27.03	28.83	30.88	28.61	30.50	32.70
Metallurgical coal	0.62	0.55	0.61	0.65	0.49	0.56	0.66	0.43	0.51	0.69
Other coal	17.41	17.78	18.57	18.90	17.91	18.63	18.99	17.72	18.56	19.25
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net coal coke imports	-0.02	0.00	0.00	0.01	-0.03	-0.03	-0.03	-0.05	-0.06	-0.07
Coal subtotal	18.01	18.32	19.18	19.55	18.37	19.16	19.61	18.10	19.01	19.87
Nuclear / uranium[17]	8.27	8.42	8.42	8.42	8.46	8.47	8.57	8.46	8.73	9.54
Biofuels heat and coproducts	0.72	0.80	0.80	0.81	0.80	0.80	0.81	0.80	0.86	0.89
Renewable energy[19]	6.96	8.23	8.19	8.44	8.38	8.81	9.79	8.77	10.09	13.05
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Electricity imports	0.18	0.11	0.11	0.11	0.09	0.10	0.10	0.11	0.11	0.13
Total	**97.14**	**98.67**	**100.84**	**103.15**	**97.52**	**102.87**	**108.50**	**97.99**	**105.73**	**116.25**
Energy use and related statistics										
Delivered energy use	71.17	72.21	73.84	75.52	70.52	74.87	79.23	70.49	76.62	84.44
Total energy use	97.14	98.67	100.84	103.15	97.52	102.87	108.50	97.99	105.73	116.25
Ethanol consumed in motor gasoline and E85	1.12	1.12	1.12	1.13	1.12	1.12	1.14	1.16	1.27	1.34
Population (millions)	317	333	334	335	354	359	363	371	380	390
Gross domestic product (billion 2009 dollars)	15,710	17,747	18,801	19,590	21,224	23,894	26,146	25,763	29,898	34,146
Carbon dioxide emissions (million metric tons)	5,405	5,343	5,499	5,631	5,210	5,514	5,791	5,160	5,549	5,979

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal water heating, and electricity generation from wind and solar photovoltaic sources.
[2]Includes ethanol and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal water heating and electricity generation from wind and solar photovoltaic sources.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[5]Includes ethane, natural gasoline, and refinery olefins.
[6]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[7]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[8]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol in motor gasoline.
[9]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[10]Includes only kerosene type.
[11]Diesel fuel for on- and off- road use.
[12]Includes aviation gasoline and lubricants.
[13]Represents consumption unattributed to the sectors above.
[14]Includes aviation gasoline, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[15]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[16]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[17]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[18]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[19]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
Btu = British thermal unit.
Note: Includes estimated consumption for petroleum and other liquids. Totals may not equal sum of components due to independent rounding. Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2013 population and gross domestic product: IHS Economics, Industry and Employment models, November 2014. 2013 carbon dioxide emissions and emission factors: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). **Projections:** EIA, AEO2015 National Energy Modeling System runs LOWMACRO.D021915A, REF2015.D021915A, and HIGHMACRO.D021915A.

Table B3. Energy prices by sector and source

(2013 dollars per million Btu, unless otherwise noted)

Sector and source	2013	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Residential										
Propane	23.3	22.8	23.0	23.1	24.2	24.4	24.6	26.4	26.6	26.9
Distillate fuel oil	27.2	21.2	21.5	21.7	25.5	26.3	26.9	31.8	32.9	34.2
Natural gas	10.0	11.1	11.6	11.9	12.5	12.8	13.4	14.7	15.5	16.6
Electricity	35.6	37.1	37.8	38.0	38.7	40.0	40.1	41.2	42.4	43.7
Commercial										
Propane	20.0	19.2	19.4	19.5	20.9	21.1	21.3	23.7	23.9	24.3
Distillate fuel oil	26.7	20.6	21.0	21.1	25.1	25.8	26.4	31.3	32.5	33.9
Residual fuel oil	22.1	14.1	14.2	14.3	17.8	18.1	18.4	24.0	24.3	24.0
Natural gas	8.1	9.1	9.6	9.8	10.3	10.4	10.8	12.1	12.6	13.4
Electricity	29.7	30.2	31.1	31.6	31.2	32.6	33.1	33.0	34.5	36.3
Industrial[1]										
Propane	20.3	19.4	19.6	19.8	21.2	21.5	21.7	24.2	24.5	24.9
Distillate fuel oil	27.3	20.9	21.2	21.4	25.5	26.1	26.7	31.6	32.7	34.2
Residual fuel oil	20.0	13.2	13.3	13.4	16.9	17.2	17.6	23.1	23.5	23.1
Natural gas[2]	4.6	5.7	6.2	6.4	6.6	6.8	7.1	8.4	8.8	9.2
Metallurgical coal	5.5	5.8	5.8	5.8	6.7	6.7	6.7	7.1	7.2	7.3
Other industrial coal	3.2	3.3	3.3	3.3	3.6	3.6	3.6	3.9	3.9	4.0
Coal to liquids	--	--	--	--	--	--	--	--	--	--
Electricity	20.2	20.7	21.3	21.6	21.6	22.6	23.1	23.5	24.7	26.0
Transportation										
Propane	24.6	23.8	24.0	24.1	25.2	25.5	25.6	27.4	27.6	27.9
E85[3]	33.1	30.1	30.4	30.7	28.7	31.2	31.5	33.9	35.4	36.9
Motor gasoline[4]	29.3	22.3	22.5	22.6	25.8	26.4	26.7	31.3	32.3	33.5
Jet fuel[5]	21.8	15.8	16.1	16.3	20.7	21.3	22.0	27.4	28.3	29.7
Diesel fuel (distillate fuel oil)[6]	28.2	22.8	23.1	23.3	27.4	28.0	28.6	33.5	34.7	36.2
Residual fuel oil	19.3	11.4	11.7	11.9	15.0	15.4	15.8	19.8	20.3	21.0
Natural gas[7]	17.6	17.2	17.8	18.2	15.3	15.7	16.5	18.6	19.6	20.7
Electricity	28.5	29.3	30.2	31.0	31.5	32.9	33.2	34.5	36.0	37.7
Electric power[8]										
Distillate fuel oil	24.0	18.5	18.8	18.9	22.8	23.6	24.2	29.1	30.2	31.6
Residual fuel oil	18.9	11.3	11.5	11.5	15.0	15.4	15.7	21.3	21.6	21.3
Natural gas	4.4	4.9	5.4	5.6	6.0	6.2	6.6	7.9	8.3	8.7
Steam coal	2.3	2.3	2.4	2.4	2.7	2.7	2.7	2.9	2.9	3.0
Average price to all users[9]										
Propane	21.9	20.8	21.1	21.2	22.3	22.6	22.8	24.9	25.2	25.6
E85[3]	33.1	30.1	30.4	30.7	28.7	31.2	31.5	33.9	35.4	36.9
Motor gasoline[4]	29.0	22.3	22.5	22.6	25.8	26.4	26.7	31.3	32.3	33.5
Jet fuel[5]	21.8	15.8	16.1	16.3	20.7	21.3	22.0	27.4	28.3	29.7
Distillate fuel oil	27.9	22.3	22.6	22.8	26.9	27.6	28.2	33.1	34.2	35.8
Residual fuel oil	19.4	12.0	12.2	12.4	15.6	16.0	16.5	21.1	21.5	21.8
Natural gas	6.1	7.0	7.5	7.6	8.0	8.2	8.5	10.0	10.5	11.1
Metallurgical coal	5.5	5.8	5.8	5.8	6.7	6.7	6.7	7.1	7.2	7.3
Other coal	2.4	2.4	2.4	2.4	2.7	2.7	2.7	3.0	3.0	3.0
Coal to liquids	--	--	--	--	--	--	--	--	--	--
Electricity	29.5	30.1	30.8	31.0	31.4	32.4	32.7	33.5	34.7	36.0
Non-renewable energy expenditures by sector (billion 2013 dollars)										
Residential	243	244	254	262	255	276	300	277	311	358
Commercial	177	188	194	197	210	219	226	245	259	277
Industrial[1]	224	247	264	279	286	323	356	344	389	454
Transportation	719	546	565	579	584	638	687	687	791	922
Total non-renewable expenditures	1,364	1,225	1,276	1,317	1,336	1,456	1,569	1,553	1,751	2,011
Transportation renewable expenditures	1	1	1	1	8	6	6	10	10	11
Total expenditures	**1,364**	**1,226**	**1,277**	**1,318**	**1,344**	**1,462**	**1,575**	**1,562**	**1,761**	**2,023**

Table B3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2013	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Residential										
Propane	23.3	27.6	26.1	26.1	41.7	32.8	31.8	66.3	43.1	41.5
Distillate fuel oil	27.2	25.6	24.4	24.5	44.0	35.3	34.8	79.7	53.3	52.8
Natural gas	10.0	13.4	13.2	13.4	21.6	17.1	17.2	36.9	25.1	25.6
Electricity	35.6	44.8	42.9	42.8	66.7	53.6	51.8	103.4	68.8	67.4
Commercial										
Propane	20.0	23.1	22.0	22.0	36.0	28.3	27.6	59.4	38.8	37.5
Distillate fuel oil	26.7	24.9	23.8	23.8	43.3	34.6	34.1	78.6	52.6	52.3
Residual fuel oil	22.1	17.0	16.1	16.1	30.6	24.3	23.8	60.3	39.4	37.0
Natural gas	8.1	11.0	10.8	11.1	17.7	13.9	14.0	30.4	20.5	20.7
Electricity	29.7	36.5	35.3	35.6	53.8	43.7	42.8	82.8	56.0	56.0
Industrial[1]										
Propane	20.3	23.4	22.3	22.3	36.6	28.8	28.1	60.7	39.7	38.4
Distillate fuel oil	27.3	25.2	24.1	24.1	43.8	35.0	34.5	79.3	53.0	52.7
Residual fuel oil	20.0	15.9	15.1	15.2	29.1	23.1	22.7	58.0	38.0	35.7
Natural gas[2]	4.6	6.9	7.0	7.2	11.4	9.1	9.2	21.0	14.2	14.2
Metallurgical coal	5.5	7.0	6.6	6.5	11.5	8.9	8.6	17.9	11.6	11.2
Other industrial coal	3.2	4.0	3.8	3.8	6.2	4.8	4.7	9.7	6.3	6.1
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	20.2	24.9	24.2	24.3	37.2	30.3	29.8	58.9	40.0	40.2
Transportation										
Propane	24.6	28.8	27.2	27.2	43.5	34.1	33.1	68.8	44.8	43.1
E85[3]	33.1	36.3	34.4	34.7	49.5	41.9	40.7	85.1	57.4	56.9
Motor gasoline[4]	29.3	27.0	25.5	25.5	44.5	35.3	34.5	78.4	52.4	51.7
Jet fuel[5]	21.8	19.1	18.3	18.3	35.6	28.6	28.4	68.7	45.8	45.9
Diesel fuel (distillate fuel oil)[6]	28.2	27.5	26.2	26.3	47.2	37.6	37.0	84.1	56.2	55.9
Residual fuel oil	19.3	13.8	13.2	13.4	25.7	20.6	20.5	49.8	32.9	32.4
Natural gas[7]	17.6	20.7	20.2	20.6	26.3	21.0	21.3	46.7	31.8	31.9
Electricity	28.5	35.4	34.3	35.0	54.3	44.1	42.8	86.6	58.4	58.1
Electric power[8]										
Distillate fuel oil	24.0	22.3	21.3	21.4	39.3	31.7	31.3	72.9	49.0	48.7
Residual fuel oil	18.9	13.7	13.0	13.0	25.9	20.6	20.3	53.4	35.0	32.8
Natural gas	4.4	6.0	6.1	6.4	10.4	8.3	8.5	19.8	13.4	13.4
Steam coal	2.3	2.8	2.7	2.7	4.6	3.6	3.5	7.3	4.7	4.6

Table B3. Energy prices by sector and source (continued)

(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2013	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Average price to all users[9]										
Propane	21.9	25.1	23.9	23.9	38.4	30.3	29.5	62.4	40.9	39.5
E85[3]	33.1	36.3	34.4	34.7	49.5	41.9	40.7	85.1	57.4	56.9
Motor gasoline[4]	29.0	27.0	25.5	25.5	44.5	35.3	34.5	78.4	52.4	51.7
Jet fuel[5]	21.8	19.1	18.3	18.3	35.6	28.6	28.4	68.7	45.8	45.9
Distillate fuel oil	27.9	26.9	25.7	25.7	46.4	36.9	36.4	83.0	55.5	55.2
Residual fuel oil	19.4	14.5	13.8	14.0	26.9	21.5	21.3	52.8	34.8	33.6
Natural gas	6.1	8.5	8.5	8.6	13.9	11.0	11.0	25.1	17.0	17.1
Metallurgical coal	5.5	7.0	6.6	6.5	11.5	8.9	8.6	17.9	11.6	11.2
Other coal	2.4	2.9	2.8	2.8	4.7	3.7	3.5	7.4	4.8	4.7
Coal to liquids	- -	- -	- -	- -	- -	- -	- -	- -	- -	- -
Electricity	29.5	36.4	34.9	35.0	54.0	43.4	42.2	83.9	56.2	55.5
Non-renewable energy expenditures by sector (billion nominal dollars)										
Residential	243	295	288	296	440	370	387	694	504	553
Commercial	177	227	220	223	362	294	292	614	420	428
Industrial[1]	224	298	299	314	493	433	460	863	631	700
Transportation	719	660	641	654	1,006	855	888	1,724	1,283	1,422
Total non-renewable expenditures	1,364	1,479	1,448	1,487	2,301	1,952	2,027	3,894	2,839	3,103
Transportation renewable expenditures	1	1	1	1	13	8	8	24	16	17
Total expenditures	**1,364**	**1,480**	**1,449**	**1,488**	**2,314**	**1,960**	**2,035**	**3,919**	**2,855**	**3,120**

[1]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Excludes use for lease and plant fuel.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
[5]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Natural gas used as fuel in motor vehicles, trains, and ships. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[8]Includes electricity-only and combined heat and power plants that have a regulatory status.
[9]*Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.*
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2014/08) (Washington, DC, August 2014). 2013 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). 2013 transportation sector natural gas delivered prices are model results. 2013 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2013 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2013 and April 2014, Table 4.2, and EIA, *State Energy Data Report 2012*, DOE/EIA-0214(2012) (Washington, DC, June 2014). 2013 coal prices based on: EIA, *Quarterly Coal Report, October-December 2013*, DOE/EIA-0121(2013/4Q) (Washington, DC, March 2014) and EIA, AEO2015 National Energy Modeling System run REF2015.D021915A. 2013 electricity prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2013 E85 prices *derived from monthly prices in the Clean Cities Alternative Fuel Price Report.* **Projections:** EIA, AEO2015 National Energy Modeling System runs LOWMACRO.D021915A, REF2015.D021915A, and HIGHMACRO.D021915A.

Table B4. Macroeconomic indicators
(billion 2009 chain-weighted dollars, unless otherwise noted)

Indicators	2013	Projections								
		2020			2030			2040		
		Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth	Low economic growth	Reference	High economic growth
Real gross domestic product	**15,710**	**17,747**	**18,801**	**19,590**	**21,224**	**23,894**	**26,146**	**25,763**	**29,898**	**34,146**
Components of real gross domestic product										
Real consumption	10,700	12,214	12,832	13,285	14,368	16,275	17,804	17,094	20,476	22,973
Real investment	2,556	3,157	3,531	3,923	3,828	4,474	5,146	4,685	5,634	6,720
Real government spending	2,894	2,926	2,985	3,039	3,130	3,286	3,423	3,441	3,691	3,943
Real exports	2,020	2,623	2,813	2,935	4,039	4,815	5,395	5,818	7,338	9,163
Real imports	2,440	3,158	3,334	3,563	4,142	4,888	5,535	5,152	7,037	8,334
Energy intensity (thousand Btu per 2009 dollar of GDP)										
Delivered energy	4.53	4.07	3.93	3.86	3.32	3.13	3.03	2.74	2.56	2.47
Total energy	6.18	5.56	5.36	5.27	4.59	4.31	4.15	3.80	3.54	3.40
Price indices										
GDP chain-type price index (2009=1.000)	1.07	1.29	1.21	1.20	1.84	1.43	1.38	2.68	1.73	1.65
Consumer price index (1982-4=1.00)										
All-urban	2.33	2.79	2.63	2.62	4.06	3.18	3.06	6.08	3.95	3.77
Energy commodities and services	2.44	2.67	2.55	2.56	4.28	3.42	3.35	7.26	4.85	4.82
Wholesale price index (1982=1.00)										
All commodities	2.03	2.38	2.25	2.27	3.46	2.71	2.64	5.21	3.39	3.32
Fuel and power	2.12	2.34	2.26	2.28	3.84	3.08	3.03	6.84	4.56	4.56
Metals and metal products	2.14	2.55	2.43	2.54	3.54	2.85	2.89	4.96	3.42	3.59
Industrial commodities excluding energy	1.96	2.36	2.22	2.24	3.36	2.61	2.54	4.81	3.12	3.04
Interest rates (percent, nominal)										
Federal funds rate	0.11	5.28	3.40	3.07	6.92	3.69	3.60	7.72	4.04	3.89
10-year treasury note	2.35	5.29	4.12	3.87	6.60	4.28	4.16	7.52	4.63	4.53
AA utility bond rate	4.24	7.73	6.15	5.35	9.23	6.33	5.59	10.34	6.71	5.69
Value of shipments (billion 2009 dollars)										
Non-industrial and service sectors	24,398	27,029	28,468	29,598	31,111	34,968	38,353	34,777	40,814	46,610
Total industrial	7,004	7,848	8,467	8,967	8,608	9,870	11,081	9,755	11,463	13,786
Agriculture, mining, and construction	1,858	2,135	2,344	2,552	2,165	2,540	2,922	2,257	2,712	3,200
Manufacturing	5,146	5,713	6,123	6,415	6,443	7,330	8,159	7,498	8,751	10,586
Energy-intensive	1,685	1,866	1,946	2,006	1,994	2,168	2,331	2,121	2,317	2,607
Non-energy-intensive	3,461	3,847	4,177	4,409	4,449	5,162	5,828	5,377	6,433	7,979
Total shipments	**31,402**	**34,878**	**36,935**	**38,566**	**39,720**	**44,838**	**49,433**	**44,532**	**52,277**	**60,396**
Population and employment (millions)										
Population, with armed forces overseas	317	333	334	335	354	359	363	371	380	390
Population, aged 16 and over	251	266	267	267	284	288	291	300	307	315
Population, aged 65 and over	45	56	56	56	73	73	73	80	80	81
Employment, nonfarm	136	146	149	152	153	159	166	160	169	176
Employment, manufacturing	11.9	11.3	11.8	12.2	9.7	10.7	11.4	8.4	9.7	10.7
Key labor indicators										
Labor force (millions)	155	165	166	166	171	174	177	179	185	190
Non-farm labor productivity (2009=1.00)	1.05	1.16	1.20	1.22	1.38	1.48	1.54	1.59	1.78	1.90
Unemployment rate (percent)	7.35	5.70	5.40	5.20	5.41	5.03	4.50	4.89	4.85	4.57
Key indicators for energy demand										
Real disposable personal income	11,651	13,944	14,411	14,900	17,469	18,487	19,806	21,555	22,957	24,875
Housing starts (millions)	0.99	1.21	1.69	2.28	1.05	1.66	2.44	0.96	1.62	2.55
Commercial floorspace (billion square feet)	82.8	88.6	89.0	89.5	96.8	98.4	100.1	106.0	109.1	112.4
Unit sales of light-duty vehicles (millions)	15.5	16.1	17.0	17.8	15.6	17.5	18.3	15.0	18.2	19.9

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2013: IHS Economics, Industry and Employment models, November 2014. **Projections:** U.S. Energy Information Administration, AEO2015 National Energy Modeling System runs LOWMACRO.D021915A, REF2015.D021915A, and HIGHMACRO.D021915A.

Appendix C

Price case comparisons

Table C1. Total energy supply, disposition, and price summary

(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Production										
Crude oil and lease condensate	15.6	20.9	22.2	25.6	18.2	21.1	26.2	15.0	19.9	20.9
Natural gas plant liquids	3.6	5.3	5.5	5.8	5.4	5.7	6.3	5.0	5.5	6.2
Dry natural gas	25.1	28.3	29.6	30.9	31.0	33.9	39.1	32.8	36.4	42.2
Coal[1]	20.0	21.4	21.7	21.4	22.5	22.5	23.5	22.6	22.6	25.4
Nuclear / uranium[2]	8.3	8.4	8.4	8.4	8.5	8.5	8.7	8.5	8.7	9.8
Conventional hydroelectric power	2.5	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Biomass[3]	4.2	4.4	4.4	4.5	4.6	4.6	4.8	4.7	5.0	5.7
Other renewable energy[4]	2.3	3.2	3.2	3.4	3.5	3.6	4.0	4.1	4.6	6.4
Other[5]	1.3	0.9	0.9	0.9	0.9	0.9	1.0	0.9	1.0	1.0
Total	**82.7**	**95.6**	**98.7**	**103.8**	**97.4**	**103.7**	**116.6**	**96.5**	**106.6**	**120.5**
Imports										
Crude oil	17.0	14.7	13.6	14.6	17.0	15.7	15.3	19.2	18.2	21.0
Petroleum and other liquids[6]	4.3	5.4	4.6	3.8	5.6	4.4	4.2	5.3	4.1	4.0
Natural gas[7]	2.9	1.9	1.9	1.9	1.6	1.6	1.7	2.0	1.7	2.0
Other imports[8]	0.3	0.1	0.1	0.2	0.1	0.1	0.2	0.1	0.1	0.9
Total	**24.5**	**22.1**	**20.2**	**20.4**	**24.3**	**21.7**	**21.4**	**26.6**	**24.1**	**28.0**
Exports										
Petroleum and other liquids[9]	7.3	10.9	11.2	16.5	10.7	12.6	21.2	8.1	13.7	24.0
Natural gas[10]	1.6	3.1	4.5	4.5	4.0	6.4	10.2	5.0	7.4	11.2
Coal	2.9	2.5	2.5	2.4	3.3	3.3	3.0	3.7	3.5	3.3
Total	**11.7**	**16.5**	**18.1**	**23.4**	**18.0**	**22.4**	**34.4**	**16.8**	**24.6**	**38.5**
Discrepancy[11]	**-1.6**	**-0.1**	**-0.1**	**-0.1**	**0.1**	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**
Consumption										
Petroleum and other liquids[12]	35.9	37.8	37.1	35.8	37.8	36.5	33.7	38.6	36.2	32.9
Natural gas	26.9	26.8	26.8	28.0	28.4	28.8	30.2	29.6	30.5	31.8
Coal[13]	18.0	18.9	19.2	19.0	19.1	19.2	20.1	18.8	19.0	21.6
Nuclear / uranium[2]	8.3	8.4	8.4	8.4	8.5	8.5	8.7	8.5	8.7	9.8
Conventional hydroelectric power	2.5	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Biomass[14]	2.9	3.0	3.0	3.1	3.1	3.2	3.4	3.3	3.5	4.0
Other renewable energy[4]	2.3	3.2	3.2	3.4	3.5	3.6	4.0	4.1	4.6	6.4
Other[15]	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4
Total	**97.1**	**101.2**	**100.8**	**100.8**	**103.6**	**102.9**	**103.3**	**106.1**	**105.7**	**109.7**
Prices (2013 dollars per unit)										
Crude oil spot prices (dollars per barrel)										
Brent	109	58	79	149	69	106	194	76	141	252
West Texas Intermediate	98	52	73	142	63	99	188	72	136	246
Natural gas at Henry Hub (dollars per million Btu)	3.73	4.30	4.88	4.61	5.49	5.69	7.89	7.15	7.85	10.63
Coal (dollars per ton) at the minemouth[16]	37.2	37.2	37.9	39.8	42.1	43.7	47.4	46.4	49.2	52.7
Coal (dollars per million Btu) at the minemouth[16]	1.84	1.85	1.88	1.98	2.11	2.18	2.35	2.31	2.44	2.62
Average end-use[17]	2.50	2.47	2.54	2.72	2.72	2.84	3.10	2.87	3.09	3.43
Average electricity (cents per kilowatthour)	10.1	10.4	10.5	10.5	11.0	11.1	11.8	11.5	11.8	12.9

Table C1. Total energy supply, disposition, and price summary (continued)
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Prices (nominal dollars per unit)										
Crude oil spot prices (dollars per barrel)										
Brent	109	65	90	167	91	142	263	120	229	416
West Texas Intermediate	98	58	83	159	83	133	255	115	220	407
Natural gas at Henry Hub (dollars per million Btu)	3.73	4.87	5.54	5.18	7.26	7.63	10.72	11.41	12.73	17.57
Coal (dollars per ton) at the minemouth[16]	37.2	42.1	43.0	44.8	55.7	58.6	64.4	74.0	79.8	87.1
Coal (dollars per million Btu)										
at the minemouth[16]	1.84	2.09	2.14	2.22	2.78	2.92	3.20	3.68	3.96	4.34
Average end-use[17]	2.50	2.79	2.88	3.06	3.60	3.81	4.22	4.58	5.00	5.67
Average electricity (cents per kilowatthour)	10.1	11.7	11.9	11.8	14.5	14.8	16.0	18.4	19.2	21.3

[1]Includes waste coal.
[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[3]Includes grid-connected electricity from wood and wood waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[4]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy data.
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes imports of liquefied natural gas that are later re-exported.
[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.
[9]Includes crude oil, petroleum products, ethanol, and biodiesel.
[10]Includes re-exported liquefied natural gas.
[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[12]Estimated consumption. Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are hydrocarbon gas liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[13]Excludes coal converted to coal-based synthetic liquids and natural gas.
[14]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[16]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[17]Prices weighted by consumption; weighted average excludes export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 natural gas supply values: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). 2013 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2013*, DOE/EIA-0584(2013) (Washington, DC, January 2015). 2013 petroleum supply values: EIA, *Petroleum Supply Annual 2013*, DOE/EIA-0340(2013)/1 (Washington, DC, September 2014). 2013 crude oil spot prices and natural gas spot price at Henry Hub: Thomson Reuters. Other 2013 coal values: *Quarterly Coal Report, October-December 2013*, DOE/EIA-0121(2013/4Q) (Washington, DC, March 2014). Other 2013 values: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). **Projections:** EIA, AEO2015 National Energy Modeling System runs LOWPRICE.D021915A, REF2015.D021915A, and HIGHPRICE.D021915A.

Table C2. Energy consumption by sector and source
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Energy consumption										
Residential										
Propane	0.43	0.33	0.32	0.31	0.29	0.28	0.26	0.26	0.25	0.23
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00
Distillate fuel oil	0.50	0.42	0.40	0.36	0.33	0.31	0.28	0.27	0.24	0.21
Petroleum and other liquids subtotal	0.93	0.76	0.73	0.68	0.63	0.59	0.54	0.53	0.49	0.45
Natural gas	5.05	4.65	4.63	4.64	4.53	4.52	4.43	4.35	4.31	4.20
Renewable energy[1]	0.58	0.37	0.41	0.53	0.32	0.38	0.48	0.28	0.35	0.45
Electricity	4.75	4.87	4.86	4.81	5.10	5.08	4.97	5.48	5.42	5.25
Delivered energy	**11.32**	**10.65**	**10.63**	**10.66**	**10.58**	**10.57**	**10.42**	**10.63**	**10.57**	**10.34**
Electricity related losses	9.79	9.75	9.75	9.58	9.94	9.91	9.74	10.38	10.33	10.30
Total	**21.10**	**20.40**	**20.38**	**20.25**	**20.52**	**20.48**	**20.16**	**21.01**	**20.91**	**20.64**
Commercial										
Propane	0.15	0.17	0.16	0.15	0.18	0.17	0.16	0.20	0.18	0.16
Motor gasoline[2]	0.05	0.05	0.05	0.04	0.06	0.05	0.05	0.06	0.06	0.05
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
Distillate fuel oil	0.37	0.36	0.34	0.29	0.33	0.30	0.26	0.32	0.27	0.23
Residual fuel oil	0.03	0.08	0.07	0.05	0.08	0.07	0.05	0.09	0.06	0.05
Petroleum and other liquids subtotal	0.59	0.66	0.62	0.54	0.66	0.60	0.52	0.67	0.58	0.50
Natural gas	3.37	3.33	3.30	3.33	3.43	3.43	3.29	3.75	3.71	3.53
Coal	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Renewable energy[3]	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Electricity	4.57	4.83	4.82	4.80	5.21	5.19	5.11	5.70	5.66	5.54
Delivered energy	**8.69**	**8.98**	**8.90**	**8.84**	**9.46**	**9.38**	**9.09**	**10.29**	**10.12**	**9.73**
Electricity related losses	9.42	9.66	9.68	9.57	10.14	10.13	10.01	10.80	10.80	10.87
Total	**18.10**	**18.64**	**18.58**	**18.41**	**19.60**	**19.52**	**19.10**	**21.09**	**20.92**	**20.60**
Industrial[4]										
Liquefied petroleum gases and other[5]	2.51	3.24	3.20	3.28	3.79	3.72	3.72	3.78	3.67	3.76
Motor gasoline[2]	0.25	0.26	0.26	0.27	0.25	0.25	0.26	0.24	0.25	0.24
Distillate fuel oil	1.31	1.39	1.42	1.39	1.37	1.36	1.33	1.36	1.35	1.28
Residual fuel oil	0.06	0.13	0.10	0.09	0.17	0.13	0.11	0.18	0.13	0.12
Petrochemical feedstocks	0.74	0.97	0.95	0.98	1.15	1.14	1.13	1.19	1.20	1.16
Other petroleum[6]	3.52	3.73	3.67	3.95	3.88	3.83	3.96	4.03	3.99	4.06
Petroleum and other liquids subtotal	8.40	9.72	9.61	9.96	10.61	10.44	10.52	10.79	10.59	10.62
Natural gas	7.62	8.20	8.33	8.50	8.56	8.65	8.82	8.50	8.90	9.29
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.16	0.00	0.00	0.96
Lease and plant fuel[7]	1.52	1.67	1.87	1.98	1.75	2.10	2.94	1.80	2.29	3.31
Natural gas subtotal	9.14	9.87	10.20	10.48	10.30	10.75	11.92	10.30	11.19	13.55
Metallurgical coal	0.62	0.58	0.61	0.65	0.55	0.56	0.61	0.48	0.51	0.58
Other industrial coal	0.88	0.92	0.93	0.97	0.94	0.96	1.04	0.95	0.99	1.13
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.68	0.00	0.00	1.97
Net coal coke imports	-0.02	0.00	0.00	0.01	-0.03	-0.03	-0.03	-0.06	-0.06	-0.05
Coal subtotal	1.48	1.50	1.54	1.63	1.46	1.48	2.29	1.38	1.44	3.63
Biofuels heat and coproducts	0.72	0.82	0.80	0.80	0.81	0.80	0.81	0.80	0.86	0.98
Renewable energy[8]	1.48	1.55	1.53	1.59	1.61	1.59	1.61	1.61	1.63	1.81
Electricity	3.26	3.75	3.74	3.98	4.02	4.04	4.21	4.00	4.12	4.35
Delivered energy	**24.48**	**27.21**	**27.42**	**28.43**	**28.81**	**29.10**	**31.36**	**28.86**	**29.82**	**34.96**
Electricity related losses	6.72	7.51	7.51	7.93	7.83	7.88	8.25	7.58	7.85	8.54
Total	**31.20**	**34.72**	**34.93**	**36.36**	**36.64**	**36.98**	**39.61**	**36.44**	**37.68**	**43.48**

Table C2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Transportation										
Propane	0.05	0.04	0.04	0.06	0.05	0.05	0.07	0.05	0.07	0.09
Motor gasoline[2]	15.94	15.94	15.35	13.98	14.31	13.30	11.44	14.18	12.55	10.54
of which: E85[9]	0.02	0.02	0.03	0.19	0.14	0.20	0.52	0.16	0.28	0.76
Jet fuel[10]	2.80	3.02	3.01	2.97	3.42	3.40	3.37	3.65	3.64	3.61
Distillate fuel oil[11]	6.50	7.27	7.35	7.26	7.84	7.76	6.88	8.44	7.97	6.68
Residual fuel oil	0.57	0.35	0.35	0.35	0.36	0.36	0.36	0.36	0.36	0.36
Other petroleum[12]	0.15	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Petroleum and other liquids subtotal	26.00	26.78	26.27	24.79	26.13	25.03	22.28	26.84	24.76	21.46
Pipeline fuel natural gas	0.88	0.83	0.85	0.89	0.90	0.94	1.04	0.91	0.96	1.07
Compressed / liquefied natural gas	0.05	0.06	0.07	0.39	0.06	0.17	1.31	0.06	0.71	2.47
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.03	0.04	0.04	0.05	0.05	0.06	0.08
Delivered energy	**26.96**	**27.70**	**27.22**	**26.10**	**27.13**	**26.18**	**24.68**	**27.87**	**26.49**	**25.08**
Electricity related losses	0.05	0.06	0.06	0.07	0.08	0.08	0.10	0.10	0.12	0.16
Total	**27.01**	**27.76**	**27.29**	**26.17**	**27.21**	**26.27**	**24.78**	**27.98**	**26.61**	**25.24**
Unspecified sector[13]	**-0.27**	**-0.33**	**-0.34**	**-0.35**	**-0.37**	**-0.37**	**-0.31**	**-0.41**	**-0.38**	**-0.29**
Delivered energy consumption for all sectors										
Liquefied petroleum gases and other[5]	3.14	3.78	3.73	3.79	4.31	4.23	4.21	4.29	4.17	4.25
Motor gasoline[2]	16.36	16.38	15.79	14.41	14.74	13.72	11.84	14.60	12.96	10.91
of which: E85[9]	0.02	0.02	0.03	0.19	0.14	0.20	0.52	0.16	0.28	0.76
Jet fuel[10]	2.97	3.20	3.20	3.15	3.62	3.61	3.57	3.88	3.86	3.83
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	8.10	8.80	8.86	8.66	9.18	9.05	8.14	9.63	9.13	7.81
Residual fuel oil	0.65	0.57	0.53	0.50	0.61	0.56	0.52	0.63	0.56	0.53
Petrochemical feedstocks	0.74	0.97	0.95	0.98	1.15	1.14	1.13	1.19	1.20	1.16
Other petroleum[14]	3.67	3.89	3.82	4.11	4.04	3.98	4.12	4.19	4.15	4.22
Petroleum and other liquids subtotal	35.65	37.59	36.89	35.61	37.66	36.30	33.54	38.43	36.03	32.73
Natural gas	16.10	16.24	16.32	16.86	16.57	16.76	17.84	16.67	17.64	19.48
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.16	0.00	0.00	0.96
Lease and plant fuel[7]	1.52	1.67	1.87	1.98	1.75	2.10	2.94	1.80	2.29	3.31
Pipeline natural gas	0.88	0.83	0.85	0.89	0.90	0.94	1.04	0.91	0.96	1.07
Natural gas subtotal	18.50	18.73	19.05	19.73	19.21	19.80	21.99	19.37	20.88	24.81
Metallurgical coal	0.62	0.58	0.61	0.65	0.55	0.56	0.61	0.48	0.51	0.58
Other coal	0.92	0.97	0.98	1.02	0.99	1.00	1.09	1.00	1.04	1.18
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.68	0.00	0.00	1.97
Net coal coke imports	-0.02	0.00	0.00	0.01	-0.03	-0.03	-0.03	-0.06	-0.06	-0.05
Coal subtotal	1.52	1.55	1.59	1.67	1.51	1.53	2.34	1.42	1.49	3.68
Biofuels heat and coproducts	0.72	0.82	0.80	0.80	0.81	0.80	0.81	0.80	0.86	0.98
Renewable energy[15]	2.18	2.04	2.06	2.23	2.05	2.09	2.22	2.01	2.10	2.38
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	12.60	13.48	13.45	13.63	14.37	14.35	14.34	15.23	15.25	15.21
Delivered energy	**71.17**	**74.22**	**73.84**	**73.68**	**75.61**	**74.87**	**75.24**	**77.25**	**76.62**	**79.80**
Electricity related losses	25.97	26.98	27.00	27.15	27.99	28.01	28.09	28.86	29.10	29.87
Total	**97.14**	**101.20**	**100.84**	**100.84**	**103.60**	**102.87**	**103.34**	**106.11**	**105.73**	**109.67**
Electric power[16]										
Distillate fuel oil	0.05	0.09	0.09	0.09	0.08	0.08	0.08	0.08	0.08	0.08
Residual fuel oil	0.21	0.08	0.08	0.09	0.09	0.09	0.09	0.11	0.09	0.09
Petroleum and other liquids subtotal	0.26	0.17	0.17	0.17	0.18	0.17	0.17	0.19	0.18	0.18
Natural gas	8.36	8.07	7.80	8.28	9.21	9.03	8.25	10.19	9.61	7.02
Steam coal	16.49	17.37	17.59	17.33	17.58	17.63	17.77	17.41	17.52	17.88
Nuclear / uranium[17]	8.27	8.42	8.42	8.42	8.46	8.47	8.67	8.52	8.73	9.78
Renewable energy[18]	4.78	6.08	6.13	6.24	6.59	6.72	7.22	7.46	7.99	9.85
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Electricity imports	0.18	0.11	0.11	0.11	0.10	0.10	0.12	0.11	0.11	0.15
Total	**38.57**	**40.46**	**40.45**	**40.78**	**42.36**	**42.35**	**42.43**	**44.09**	**44.36**	**45.08**

Table C2. Energy consumption by sector and source (continued)

(quadrillion Btu per year, unless otherwise noted)

Sector and source	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Total energy consumption										
Liquefied petroleum gases and other[5]	3.14	3.78	3.73	3.79	4.31	4.23	4.21	4.29	4.17	4.25
Motor gasoline[2]	16.36	16.38	15.79	14.41	14.74	13.72	11.84	14.60	12.96	10.91
of which: E85[9]	0.02	0.02	0.03	0.19	0.14	0.20	0.52	0.16	0.28	0.76
Jet fuel[10]	2.97	3.20	3.20	3.15	3.62	3.61	3.57	3.88	3.86	3.83
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	8.15	8.88	8.95	8.75	9.27	9.13	8.23	9.71	9.21	7.90
Residual fuel oil	0.87	0.65	0.61	0.59	0.70	0.64	0.61	0.74	0.65	0.62
Petrochemical feedstocks	0.74	0.97	0.95	0.98	1.15	1.14	1.13	1.19	1.20	1.16
Other petroleum[14]	3.67	3.89	3.82	4.11	4.04	3.98	4.12	4.19	4.15	4.22
Petroleum and other liquids subtotal	35.91	37.77	37.06	35.79	37.84	36.47	33.72	38.61	36.21	32.91
Natural gas	24.46	24.31	24.12	25.14	25.78	25.79	26.09	26.86	27.25	26.50
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.16	0.00	0.00	0.96
Lease and plant fuel[7]	1.52	1.67	1.87	1.98	1.75	2.10	2.94	1.80	2.29	3.31
Pipeline natural gas	0.88	0.83	0.85	0.89	0.90	0.94	1.04	0.91	0.96	1.07
Natural gas subtotal	26.86	26.81	26.85	28.02	28.43	28.83	30.24	29.56	30.50	31.83
Metallurgical coal	0.62	0.58	0.61	0.65	0.55	0.56	0.61	0.48	0.51	0.58
Other coal	17.41	18.34	18.57	18.35	18.57	18.63	18.86	18.40	18.56	19.06
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.68	0.00	0.00	1.97
Net coal coke imports	-0.02	0.00	0.00	0.01	-0.03	-0.03	-0.03	-0.06	-0.06	-0.05
Coal subtotal	18.01	18.92	19.18	19.00	19.09	19.16	20.11	18.83	19.01	21.56
Nuclear / uranium[17]	8.27	8.42	8.42	8.42	8.46	8.47	8.67	8.52	8.73	9.78
Biofuels heat and coproducts	0.72	0.82	0.80	0.80	0.81	0.80	0.81	0.80	0.86	0.98
Renewable energy[19]	6.96	8.12	8.19	8.47	8.64	8.81	9.44	9.46	10.09	12.23
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Electricity imports	0.18	0.11	0.11	0.11	0.10	0.10	0.12	0.11	0.11	0.15
Total	**97.14**	**101.20**	**100.84**	**100.84**	**103.60**	**102.87**	**103.34**	**106.11**	**105.73**	**109.67**
Energy use and related statistics										
Delivered energy use	71.17	74.22	73.84	73.68	75.61	74.87	75.24	77.25	76.62	79.80
Total energy use	97.14	101.20	100.84	100.84	103.60	102.87	103.34	106.11	105.73	109.67
Ethanol consumed in motor gasoline and E85	1.12	1.16	1.12	1.13	1.11	1.12	1.17	1.12	1.27	1.28
Population (millions)	317	334	334	334	359	359	359	380	380	380
Gross domestic product (billion 2009 dollars).	15,710	18,742	18,801	18,798	23,963	23,894	23,844	29,885	29,898	29,760
Carbon dioxide emissions (million metric tons)	5,405	5,523	5,499	5,441	5,585	5,514	5,461	5,671	5,549	5,584

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal water heating, and electricity generation from wind and solar photovoltaic sources.
[2]Includes ethanol and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal water heating and electricity generation from wind and solar photovoltaic sources.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[5]Includes ethane, natural gasoline, and refinery olefins.
[6]*Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.*
[7]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[8]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol in motor gasoline.
[9]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[10]Includes only kerosene type.
[11]Diesel fuel for on- and off- road use.
[12]Includes aviation gasoline and lubricants.
[13]Represents consumption unattributed to the sectors above.
[14]Includes aviation gasoline, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[15]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[16]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[17]*These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.*
[18]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[19]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
Btu = British thermal unit.
Note: Includes estimated consumption for petroleum and other liquids. Totals may not equal sum of components due to independent rounding. Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE-EIA-0035(2014/11) (Washington, DC, November 2014). 2013 population and gross domestic product: IHS Economics, Industry and Employment models, November 2014. 2013 carbon dioxide emissions and emission factors: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). **Projections:** EIA, AEO2015 National Energy Modeling System runs LOWPRICE.D021915A, REF2015.D021915A, and HIGHPRICE.D021915A.

Table C3. Energy prices by sector and source

(2013 dollars per million Btu, unless otherwise noted)

Sector and source	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil Price	Reference	High oil price
Residential										
Propane	23.3	21.2	23.0	26.6	22.2	24.4	28.6	23.0	26.6	30.8
Distillate fuel oil	27.2	17.5	21.5	34.6	19.5	26.3	43.3	20.5	32.9	53.7
Natural gas	10.0	11.1	11.6	11.3	12.8	12.8	14.7	14.8	15.5	17.9
Electricity	35.6	37.3	37.8	38.3	39.6	40.0	42.7	41.3	42.4	46.3
Commercial										
Propane	20.0	17.2	19.4	23.9	18.4	21.1	26.6	19.4	23.9	29.5
Distillate fuel oil	26.7	16.9	21.0	34.1	19.0	25.8	42.9	19.9	32.5	53.3
Residual fuel oil	22.1	11.0	14.2	24.4	12.6	18.1	31.7	13.5	24.3	42.7
Natural gas	8.1	9.1	9.6	9.3	10.4	10.4	12.2	12.0	12.6	15.0
Electricity	29.7	30.8	31.1	31.3	32.3	32.6	34.9	33.6	34.5	37.8
Industrial[1]										
Propane	20.3	17.3	19.6	24.5	18.6	21.5	27.3	19.7	24.5	30.5
Distillate fuel oil	27.3	17.1	21.2	34.3	19.3	26.1	43.2	20.2	32.7	53.6
Residual fuel oil	20.0	10.2	13.3	23.5	11.8	17.2	30.7	12.7	23.5	41.7
Natural gas[2]	4.6	5.6	6.2	5.8	6.8	6.8	8.7	8.2	8.8	11.0
Metallurgical coal	5.5	5.8	5.8	6.0	6.6	6.7	6.9	7.0	7.2	7.5
Other industrial coal	3.2	3.3	3.3	3.5	3.5	3.6	3.9	3.7	3.9	4.3
Coal to liquids	--	--	--	--	--	--	2.6	--	--	3.1
Electricity	20.2	20.9	21.3	21.3	22.4	22.6	24.5	24.0	24.7	27.3
Transportation										
Propane	24.6	22.2	24.0	27.6	23.2	25.5	29.6	24.1	27.6	31.8
E85[3]	33.1	28.4	30.4	36.6	25.6	31.2	39.3	28.2	35.4	47.5
Motor gasoline[4]	29.3	19.2	22.5	34.4	20.2	26.4	41.7	21.4	32.3	52.5
Jet fuel[5]	21.8	12.1	16.1	28.9	14.4	21.3	38.2	15.6	28.3	48.8
Diesel fuel (distillate fuel oil)[6]	28.2	19.1	23.1	36.3	21.3	28.0	45.0	22.1	34.7	55.6
Residual fuel oil	19.3	8.7	11.7	21.0	10.5	15.4	27.6	11.3	20.3	35.4
Natural gas[7]	17.6	17.8	17.8	18.8	18.6	15.7	20.9	19.7	19.6	22.9
Electricity	28.5	29.8	30.2	30.2	32.5	32.9	35.9	34.8	36.0	40.3
Electric power[8]										
Distillate fuel oil	24.0	14.7	18.8	31.8	16.7	23.6	40.6	17.7	30.2	51.0
Residual fuel oil	18.9	8.3	11.5	21.7	9.7	15.4	28.9	10.4	21.6	40.0
Natural gas	4.4	4.9	5.4	5.1	6.2	6.2	7.9	7.8	8.3	10.1
Steam coal	2.3	2.3	2.4	2.6	2.6	2.7	3.0	2.7	2.9	3.3
Average price to all users[9]										
Propane	21.9	19.0	21.1	25.3	19.8	22.6	27.7	20.8	25.2	30.5
E85[3]	33.1	28.4	30.4	36.6	25.6	31.2	39.3	28.2	35.4	47.5
Motor gasoline[4]	29.0	19.2	22.5	34.4	20.2	26.4	41.7	21.4	32.3	52.5
Jet fuel[5]	21.8	12.1	16.1	28.9	14.4	21.3	38.2	15.6	28.3	48.8
Distillate fuel oil	27.9	18.6	22.6	35.8	20.8	27.6	44.6	21.7	34.2	55.1
Residual fuel oil	19.4	9.3	12.2	21.8	10.9	16.0	28.7	11.8	21.5	37.8
Natural gas	6.1	6.9	7.5	7.3	8.1	8.2	10.5	9.7	10.5	13.4
Metallurgical coal	5.5	5.8	5.8	6.0	6.6	6.7	6.9	7.0	7.2	7.5
Other coal	2.4	2.4	2.4	2.6	2.6	2.7	3.0	2.8	3.0	3.4
Coal to liquids	--	--	--	--	--	--	2.6	--	--	3.1
Electricity	29.5	30.4	30.8	30.8	32.1	32.4	34.5	33.8	34.7	37.7
Non-renewable energy expenditures by sector (billion 2013 dollars)										
Residential	243	248	254	258	273	276	297	302	311	336
Commercial	177	190	194	198	216	219	238	249	259	284
Industrial[1]	224	236	264	334	285	323	439	312	389	547
Transportation	719	481	565	831	503	638	926	544	791	1,128
Total non-renewable expenditures	1,364	1,155	1,276	1,621	1,276	1,456	1,900	1,408	1,751	2,295
Transportation renewable expenditures	1	1	1	7	4	6	20	4	10	36
Total expenditures	**1,364**	**1,155**	**1,277**	**1,628**	**1,280**	**1,462**	**1,920**	**1,412**	**1,761**	**2,331**

Table C3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Residential										
Propane	23.3	24.0	26.1	29.9	29.3	32.8	38.9	36.7	43.1	50.9
Distillate fuel oil	27.2	19.8	24.4	38.8	25.8	35.3	58.8	32.7	53.3	88.7
Natural gas	10.0	12.5	13.2	12.7	16.9	17.1	20.0	23.6	25.1	29.6
Electricity	35.6	42.2	42.9	43.1	52.4	53.6	58.0	65.9	68.8	76.4
Commercial										
Propane	20.0	19.5	22.0	26.9	24.3	28.3	36.1	31.0	38.8	48.8
Distillate fuel oil	26.7	19.1	23.8	38.3	25.1	34.6	58.2	31.8	52.6	88.1
Residual fuel oil	22.1	12.4	16.1	27.5	16.7	24.3	43.0	21.5	39.4	70.6
Natural gas	8.1	10.3	10.8	10.4	13.8	13.9	16.6	19.1	20.5	24.7
Electricity	29.7	34.8	35.3	35.1	42.8	43.7	47.4	53.6	56.0	62.4
Industrial[1]										
Propane	20.3	19.6	22.3	27.5	24.5	28.8	37.1	31.4	39.7	50.4
Distillate fuel oil	27.3	19.4	24.1	38.6	25.5	35.0	58.6	32.2	53.0	88.6
Residual fuel oil	20.0	11.5	15.1	26.4	15.6	23.1	41.6	20.2	38.0	68.9
Natural gas[2]	4.6	6.4	7.0	6.5	9.0	9.1	11.8	13.2	14.2	18.2
Metallurgical coal	5.5	6.5	6.6	6.7	8.7	8.9	9.3	11.2	11.6	12.4
Other industrial coal	3.2	3.7	3.8	3.9	4.6	4.8	5.2	5.9	6.3	7.1
Coal to liquids	--	--	--	--	--	--	3.5	--	--	5.1
Electricity	20.2	23.6	24.2	24.0	29.6	30.3	33.2	38.2	40.0	45.1
Transportation										
Propane	24.6	25.1	27.2	31.1	30.6	34.1	40.3	38.4	44.8	52.6
E85[3]	33.1	32.1	34.4	41.1	33.9	41.9	53.3	44.9	57.4	78.5
Motor gasoline[4]	29.3	21.7	25.5	38.6	26.7	35.3	56.6	34.1	52.4	86.8
Jet fuel[5]	21.8	13.7	18.3	32.5	19.0	28.6	51.9	24.9	45.8	80.6
Diesel fuel (distillate fuel oil)[6]	28.2	21.6	26.2	40.7	28.1	37.6	61.2	35.3	56.2	91.8
Residual fuel oil	19.3	9.9	13.2	23.6	13.8	20.6	37.5	18.0	32.9	58.4
Natural gas[7]	17.6	20.2	20.2	21.2	24.6	21.0	28.5	31.4	31.8	37.8
Electricity	28.5	33.8	34.3	34.0	43.0	44.1	48.7	55.6	58.4	66.6
Electric power[8]										
Distillate fuel oil	24.0	16.7	21.3	35.8	22.1	31.7	55.2	28.3	49.0	84.3
Residual fuel oil	18.9	9.4	13.0	24.3	12.8	20.6	39.3	16.5	35.0	66.0
Natural gas	4.4	5.6	6.1	5.8	8.2	8.3	10.7	12.4	13.4	16.7
Steam coal	2.3	2.6	2.7	2.9	3.4	3.6	4.0	4.3	4.7	5.5

Table C3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Average price to all users[9]										
Propane	21.9	21.5	23.9	28.5	26.2	30.3	37.7	33.1	40.9	50.4
E85[3]	33.1	32.1	34.4	41.1	33.9	41.9	53.3	44.9	57.4	78.5
Motor gasoline[4]	29.0	21.7	25.5	38.6	26.7	35.3	56.6	34.1	52.4	86.8
Jet fuel[5]	21.8	13.7	18.3	32.5	19.0	28.6	51.9	24.9	45.8	80.6
Distillate fuel oil	27.9	21.0	25.7	40.2	27.5	36.9	60.6	34.6	55.5	91.0
Residual fuel oil	19.4	10.5	13.8	24.5	14.5	21.5	39.0	18.8	34.8	62.5
Natural gas	6.1	7.8	8.5	8.2	10.7	11.0	14.3	15.4	17.0	22.2
Metallurgical coal	5.5	6.5	6.6	6.7	8.7	8.9	9.3	11.2	11.6	12.4
Other coal	2.4	2.7	2.8	2.9	3.4	3.7	4.1	4.4	4.8	5.6
Coal to liquids	--	--	--	--	--	--	3.5	--	--	5.1
Electricity	29.5	34.4	34.9	34.7	42.5	43.4	46.9	54.0	56.2	62.3
Non-renewable energy expenditures by sector (billion nominal dollars)										
Residential	243	280	288	290	361	370	403	482	504	556
Commercial	177	215	220	222	286	294	323	398	420	470
Industrial[1]	224	267	299	376	376	433	597	498	631	903
Transportation	719	544	641	934	664	855	1,258	868	1,283	1,864
Total non-renewable expenditures	1,364	1,307	1,448	1,822	1,687	1,952	2,581	2,246	2,839	3,793
Transportation renewable expenditures	1	1	1	8	5	8	28	7	16	60
Total expenditures	**1,364**	**1,308**	**1,449**	**1,830**	**1,692**	**1,960**	**2,609**	**2,253**	**2,855**	**3,852**

[1]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Excludes use for lease and plant fuel.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
[5]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Natural gas used as fuel in motor vehicles, trains, and ships. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[8]Includes electricity-only and combined heat and power plants that have a regulatory status.
[9]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2014/08) (Washington, DC, August 2014). 2013 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). 2013 transportation sector natural gas delivered prices are model results. 2013 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2013 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2013 and April 2014, Table 4.2, and EIA, *State Energy Data Report 2012*, DOE/EIA-0214(2012) (Washington, DC, June 2014). 2013 coal prices based on: EIA, *Quarterly Coal Report, October-December 2013*, DOE/EIA-0121(2013/4Q) (Washington, DC, March 2014) and EIA, AEO2015 National Energy Modeling System run REF2015.D021915A. 2013 electricity prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2013 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2015 National Energy Modeling System runs LOWPRICE.D021915A, REF2015.D021915A, and HIGHPRICE.D021915A.

Table C4. Petroleum and other liquids supply and disposition
(million barrels per day, unless otherwise noted)

Supply and disposition	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	*High oil price*	*Low oil price*	Reference	*High oil price*	*Low oil price*	Reference	*High oil price*
Crude oil										
Domestic crude production[1]	7.44	9.96	10.60	12.29	8.69	10.04	12.48	7.09	9.43	9.93
Alaska	0.52	0.42	0.42	0.42	0.00	0.24	0.57	0.00	0.34	0.45
Lower 48 states	6.92	9.55	10.18	11.87	8.69	9.80	11.92	7.09	9.09	9.48
Net imports	7.60	6.02	5.51	5.94	7.07	6.44	6.24	8.05	7.58	8.86
Gross imports	7.73	6.65	6.14	6.57	7.70	7.07	6.87	8.68	8.21	9.49
Exports	0.13	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63
Other crude supply[2]	0.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total crude supply	***15.30***	***15.99***	***16.11***	***18.23***	***15.76***	***16.48***	***18.72***	***15.14***	***17.01***	***18.78***
Net product imports	-1.37	-2.19	-2.80	-5.97	-1.88	-3.56	-8.06	-0.71	-4.26	-9.49
Gross refined product imports[3]	0.82	1.45	1.21	0.88	1.72	1.31	1.27	1.65	1.26	1.31
Unfinished oil imports	0.66	0.68	0.60	0.49	0.66	0.52	0.39	0.62	0.45	0.31
Blending component imports	0.60	0.72	0.59	0.51	0.62	0.49	0.50	0.53	0.40	0.44
Exports	3.43	5.04	5.20	7.86	4.88	5.89	10.23	3.51	6.36	11.54
Refinery processing gain[4]	1.09	0.96	0.98	1.07	0.94	0.97	0.99	1.00	0.98	1.01
Product stock withdrawal	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural gas plant liquids	2.61	3.92	4.04	4.29	3.99	4.19	4.65	3.71	4.07	4.55
Supply from renewable sources	0.93	1.03	1.01	1.02	1.00	1.01	1.05	1.00	1.12	1.25
Ethanol	0.83	0.87	0.84	0.85	0.83	0.84	0.88	0.83	0.95	0.96
Domestic production	0.85	0.88	0.86	0.86	0.87	0.86	0.87	0.86	0.93	0.90
Net imports	-0.02	-0.02	-0.02	-0.01	-0.04	-0.02	0.01	-0.02	0.02	0.06
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biodiesel	0.10	0.13	0.14	0.14	0.01	0.11	0.14	0.01	0.11	0.15
Domestic production	*0.09*	*0.13*	*0.13*	*0.13*	*0.00*	*0.10*	*0.13*	*0.00*	*0.10*	*0.14*
Net imports	0.01	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other biomass-derived liquids[5]	0.00	0.03	0.03	0.03	0.15	0.06	0.03	0.15	0.06	0.15
Domestic production	0.00	0.03	0.03	0.03	0.15	0.06	0.03	0.15	0.06	0.15
Net imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquids from gas	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.00	0.00	0.49
Liquids from coal	0.00	0.00	0.00	0.00	0.00	0.00	0.24	0.00	0.00	0.71
Other[6]	0.21	0.27	0.28	0.30	0.29	0.30	0.32	0.29	0.32	0.35
Total primary supply[7]	**18.87**	**19.98**	**19.62**	**18.94**	**20.10**	**19.38**	**18.00**	**20.43**	**19.24**	**17.66**
Product supplied										
by fuel										
Liquefied petroleum gases and other[8]	2.50	2.94	2.91	2.96	3.34	3.30	3.31	3.31	3.25	3.34
Motor gasoline[9]	*8.85*	*8.80*	*8.49*	*7.77*	*7.94*	*7.41*	*6.44*	*7.86*	*7.05*	*6.02*
of which: E85[10]	0.01	0.01	0.02	0.13	0.09	0.13	0.36	0.11	0.19	0.52
Jet fuel[11]	1.43	1.55	1.55	1.53	1.76	1.75	1.73	1.88	1.87	1.86
Distillate fuel oil[12]	3.83	4.22	4.26	4.16	4.41	4.34	3.91	4.62	4.38	3.77
of which: Diesel	3.56	3.90	3.94	3.88	4.13	4.09	3.68	4.38	4.17	3.57
Residual fuel oil	0.32	0.28	0.27	0.26	0.31	0.28	0.27	0.32	0.28	0.27
Other[13]	2.04	2.20	2.18	2.30	2.36	2.33	2.39	2.45	2.43	2.45
by sector										
Residential and commercial	0.86	0.79	0.76	0.69	0.72	0.67	0.60	0.68	0.61	0.54
Industrial[14]	4.69	5.54	5.50	5.66	6.12	6.04	6.09	6.17	6.09	6.16
Transportation	13.36	13.74	13.46	12.70	13.35	12.79	11.42	13.69	12.66	11.04
Electric power[15]	0.12	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Unspecified sector[16]	-0.12	-0.15	-0.15	-0.16	-0.17	-0.17	-0.14	-0.18	-0.17	-0.13
Total product supplied	**18.96**	**20.00**	**19.65**	**18.97**	**20.10**	**19.41**	**18.04**	**20.44**	**19.27**	**17.70**
Discrepancy[17]	-0.10	-0.02	-0.03	-0.03	0.00	-0.03	-0.04	-0.01	-0.03	-0.04

Table C4. Petroleum and other liquids supply and disposition (continued)
(million barrels per day, unless otherwise noted)

Supply and disposition	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Domestic refinery distillation capacity[18]	17.8	18.8	18.8	19.0	18.8	18.8	19.3	18.8	18.8	19.3
Capacity utilization rate (percent)[19]	88.3	87.4	87.8	97.6	86.1	89.4	98.6	82.7	92.0	98.6
Net import share of product supplied (percent)	33.0	19.1	13.7	-0.2	25.7	14.8	-10.0	35.9	17.4	-3.2
Net expenditures for imported crude oil and petroleum products (billion 2013 dollars)	308	130	167	345	180	259	468	225	405	836

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude oil stock withdrawals.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes pyrolysis oils, biomass-derived Fischer-Tropsch liquids, biobutanol, and renewable feedstocks used for the on-site production of diesel and gasoline.
[6]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[7]Total crude supply, net product imports, refinery processing gain, product stock withdrawal, natural gas plant liquids, supply from renewable sources, liquids from gas, liquids from coal, and other supply.
[8]Includes ethane, natural gasoline, and refinery olefins.
[9]Includes ethanol and ethers blended into gasoline.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes only kerosene type.
[12]Includes distillate fuel oil from petroleum and biomass feedstocks.
[13]Includes kerosene, aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, and miscellaneous petroleum products.
[14]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[15]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[16]Represents consumption unattributed to the sectors above.
[17]Balancing item. Includes unaccounted for supply, losses, and gains.
[18]End-of-year operable capacity.
[19]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
Note: Totals may not equal sum of components due to independent rounding. Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 product supplied based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). Other 2013 data: EIA, *Petroleum Supply Annual 2013*, DOE/EIA-0340(2013)/1 (Washington, DC, September 2014). **Projections:** EIA, AEO2015 National Energy Modeling System runs LOWPRICE.D021915A, REF2015.D021915A, and HIGHPRICE.D021915A.

Table C5. Petroleum and other liquids prices
(2013 dollars per gallon, unless otherwise noted)

Sector and fuel	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Crude oil prices (2013 dollars per barrel)										
Brent spot	109	58	79	149	69	106	194	76	141	252
West Texas Intermediate spot	98	52	73	142	63	99	188	72	136	246
Average imported refiners acquisition cost[1]	98	50	71	139	61	96	181	68	131	237
Brent / West Texas Intermediate spread	10.7	6.1	6.2	6.8	5.9	6.2	6.3	3.4	5.6	5.7
Delivered sector product prices										
Residential										
Propane	2.13	1.93	2.10	2.43	2.02	2.23	2.61	2.10	2.43	2.81
Distillate fuel oil	3.78	2.42	2.99	4.79	2.71	3.65	6.00	2.84	4.56	7.44
Commercial										
Distillate fuel oil	3.68	2.33	2.89	4.70	2.62	3.56	5.91	2.75	4.47	7.35
Residual fuel oil	3.31	1.64	2.12	3.66	1.89	2.71	4.74	2.02	3.64	6.40
Residual fuel oil (2013 dollars per barrel)	139	69	89	154	79	114	199	85	153	269
Industrial[2]										
Propane	1.85	1.58	1.79	2.24	1.70	1.96	2.49	1.80	2.24	2.78
Distillate fuel oil	3.75	2.35	2.91	4.71	2.65	3.58	5.92	2.77	4.49	7.36
Residual fuel oil	3.00	1.52	2.00	3.52	1.76	2.58	4.59	1.89	3.51	6.24
Residual fuel oil (2013 dollars per barrel)	126	64	84	148	74	108	193	80	147	262
Transportation										
Propane	2.24	2.03	2.19	2.52	2.12	2.32	2.71	2.20	2.52	2.91
E85[3]	3.14	2.71	2.90	3.49	2.44	2.98	3.75	2.69	3.38	4.53
Ethanol wholesale price	2.37	2.49	2.49	2.63	2.22	2.35	2.67	2.30	2.64	3.26
Motor gasoline[4]	3.55	2.33	2.74	4.17	2.45	3.20	5.05	2.60	3.90	6.33
Jet fuel[5]	2.94	1.63	2.17	3.90	1.95	2.88	5.16	2.11	3.81	6.58
Diesel fuel (distillate fuel oil)[6]	3.86	2.61	3.17	4.97	2.91	3.84	6.17	3.03	4.75	7.61
Residual fuel oil	2.89	1.31	1.74	3.14	1.57	2.30	4.13	1.69	3.03	5.29
Residual fuel oil (2013 dollars per barrel)	*122*	*55*	*73*	*132*	*66*	*97*	*174*	*71*	*127*	*222*
Electric power[7]										
Distillate fuel oil	3.33	2.04	2.60	4.42	2.32	3.28	5.63	2.46	4.19	7.07
Residual fuel oil	2.83	1.24	1.71	3.24	1.45	2.30	4.33	1.55	3.23	5.98
Residual fuel oil (2013 dollars per barrel)	119	52	72	136	61	97	182	65	136	251
Average prices, all sectors[8]										
Propane	2.00	1.73	1.93	2.31	1.81	2.06	2.53	1.90	2.30	2.79
Motor gasoline[4]	3.53	2.33	2.74	4.17	2.45	3.20	5.05	2.60	3.90	6.33
Jet fuel[5]	2.94	1.63	2.17	3.90	1.95	2.88	5.16	2.11	3.81	6.58
Distillate fuel oil	3.83	2.55	3.11	4.91	2.85	3.78	6.12	2.97	4.69	7.55
Residual fuel oil	2.90	1.38	1.83	3.26	1.64	2.40	4.30	1.76	3.22	5.66
Residual fuel oil (2013 dollars per barrel)	121.71	58.16	76.70	137.11	68.77	100.80	180.46	73.94	135.10	237.79
Average	**3.16**	**2.04**	**2.46**	**3.84**	**2.18**	**2.89**	**4.66**	**2.32**	**3.62**	**5.81**

Table C5. Petroleum and other liquids prices (continued)
(nominal dollars per gallon, unless otherwise noted)

Sector and fuel	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Crude oil prices (nominal dollars per barrel)										
Brent spot	109	65	90	167	91	142	263	120	229	416
West Texas Intermediate spot	98	58	83	159	83	133	255	115	220	407
Average imported refiners acquisition cost[1]	98	57	80	156	81	129	246	108	212	391
Delivered sector product prices										
Residential										
Propane	2.13	2.19	2.38	2.73	2.67	2.99	3.55	3.36	3.94	4.65
Distillate fuel oil	3.78	2.74	3.39	5.39	3.58	4.90	8.16	4.54	7.40	12.30
Commercial										
Distillate fuel oil	3.68	2.64	3.28	5.28	3.46	4.78	8.03	4.38	7.25	12.14
Residual fuel oil	3.31	1.86	2.41	4.11	2.50	3.63	6.44	3.22	5.90	10.57
Industrial[2]										
Propane	1.85	1.79	2.04	2.51	2.24	2.63	3.39	2.87	3.62	4.60
Distillate fuel oil	3.75	2.66	3.30	5.30	3.50	4.80	8.05	4.42	7.28	12.16
Residual fuel oil	3.00	1.72	2.26	3.95	2.33	3.46	6.23	3.02	5.69	10.31
Transportation										
Propane	2.24	2.30	2.49	2.84	2.80	3.12	3.68	3.50	4.09	4.80
E85[3]	3.14	3.06	3.29	3.92	3.23	3.99	5.09	4.28	5.48	7.49
Ethanol wholesale price	2.37	2.82	2.83	2.96	2.94	3.15	3.62	3.68	4.27	5.39
Motor gasoline[4]	3.55	2.64	3.10	4.69	3.24	4.29	6.86	4.15	6.32	10.46
Jet fuel[5]	2.94	1.85	2.47	4.38	2.57	3.86	7.01	3.36	6.18	10.88
Diesel fuel (distillate fuel oil)[6]	3.86	2.96	3.60	5.58	3.85	5.15	8.39	4.83	7.70	12.58
Residual fuel oil	2.89	1.48	1.98	3.53	2.07	3.08	5.61	2.70	4.92	8.75
Electric power[7]										
Distillate fuel oil	3.33	2.31	2.95	4.96	3.07	4.39	7.65	3.93	6.79	11.69
Residual fuel oil	2.83	1.40	1.94	3.64	1.92	3.09	5.88	2.48	5.24	9.88
Average prices, all sectors[8]										
Propane	2.00	1.96	2.19	2.60	2.40	2.77	3.44	3.02	3.73	4.61
Motor gasoline[4]	3.53	2.64	3.10	4.69	3.24	4.29	6.86	4.14	6.32	10.46
Jet fuel[5]	2.94	1.85	2.47	4.38	2.57	3.86	7.01	3.36	6.18	10.88
Distillate fuel oil	3.83	2.88	3.52	5.51	3.77	5.07	8.31	4.74	7.61	12.48
Residual fuel oil (nominal dollars per barrel)	122	66	87	154	91	135	245	118	219	393
Average	**3.16**	**2.30**	**2.79**	**4.32**	**2.88**	**3.88**	**6.33**	**3.70**	**5.86**	**9.61**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
[5]Includes only kerosene type.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Includes electricity-only and combined heat and power plants that have a regulatory status.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 Brent and West Texas Intermediate crude oil spot prices: Thomson Reuters. 2013 average imported crude oil price: Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2013 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380(2014/08) (Washington, DC, August 2014). 2013 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2013 electric power prices based on: *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2013 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2013 wholesale ethanol prices derived from Bloomberg U.S. average rack price. **Projections:** EIA, AEO2015 National Energy Modeling System runs LOWPRICE.D021915A, REF2015.D021915A, and HIGHPRICE.D021915A.

Table C6. International petroleum and other liquids supply, disposition, and prices
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Crude oil spot prices										
(2013 dollars per barrel)										
Brent	109	58	79	149	69	106	194	76	141	252
West Texas Intermediate	98	52	73	142	63	99	188	72	136	246
(nominal dollars per barrel)										
Brent	109	65	90	167	91	142	263	120	229	416
West Texas Intermediate	98	58	83	159	83	133	255	115	220	407
Petroleum and other liquids consumption[1]										
OECD										
United States (50 states)	18.96	20.00	19.65	18.97	20.10	19.41	18.04	20.44	19.27	17.70
United States territories	0.30	0.32	0.31	0.30	0.35	0.34	0.33	0.40	0.38	0.38
Canada	2.29	2.40	2.31	2.20	2.45	2.21	2.06	2.61	2.14	1.94
Mexico and Chile	2.46	2.79	2.71	2.63	2.95	2.80	2.78	3.19	2.92	2.88
OECD Europe[2]	13.96	14.75	14.20	13.74	15.30	14.09	13.70	16.03	14.12	13.54
Japan	4.56	4.47	4.27	4.05	4.36	4.03	3.79	4.05	3.65	3.31
South Korea	2.43	2.71	2.58	2.42	2.80	2.53	2.36	2.81	2.40	2.24
Australia and New Zealand	1.16	1.19	1.16	1.13	1.17	1.11	1.09	1.26	1.15	1.11
Total OECD consumption	**46.14**	**48.62**	**47.20**	**45.43**	**49.49**	**46.52**	**44.16**	**50.79**	**46.04**	**43.10**
Non-OECD										
Russia	3.30	3.32	3.31	3.19	3.32	3.23	3.01	3.22	3.01	2.67
Other Europe and Eurasia[3]	2.06	2.22	2.22	2.20	2.45	2.39	2.33	2.78	2.59	2.48
China	10.67	13.05	13.13	13.04	15.95	17.03	18.31	17.38	20.19	24.04
India	3.70	4.32	4.30	4.14	5.39	5.52	5.37	6.14	6.79	6.91
Other Asia[4]	7.37	9.14	9.08	8.83	12.37	12.35	12.26	16.24	16.49	16.84
Middle East	7.61	8.49	8.40	8.42	10.20	9.56	10.22	12.50	11.13	12.72
Africa	3.42	3.99	3.93	3.82	4.93	4.78	4.75	6.41	6.18	6.28
Brazil	3.11	3.44	3.33	3.15	3.93	3.74	3.62	4.80	4.50	4.50
Other Central and South America	3.38	3.56	3.49	3.38	3.86	3.72	3.64	4.39	4.15	4.11
Total non-OECD consumption	**44.60**	**51.54**	**51.20**	**50.17**	**62.41**	**62.31**	**63.50**	**73.87**	**75.01**	**80.54**
Total consumption	**90.7**	**100.2**	**98.4**	**95.6**	**111.9**	**108.8**	**107.7**	**124.7**	**121.0**	**123.6**
Petroleum and other liquids production										
OPEC[5]										
Middle East	26.32	27.65	24.56	19.33	35.80	29.34	21.86	45.31	36.14	29.01
North Africa	2.90	3.74	3.51	3.22	4.31	3.67	3.42	4.90	4.06	3.67
West Africa	4.26	5.51	5.00	4.43	6.85	5.24	4.81	7.50	5.43	5.01
South America	3.01	3.64	3.10	2.85	4.58	3.27	2.93	5.59	3.79	3.18
Total OPEC production	**36.49**	**40.54**	**36.16**	**29.83**	**51.54**	**41.53**	**33.01**	**63.30**	**49.42**	**40.87**
Non-OPEC										
OECD										
United States (50 states)	12.64	16.17	16.92	18.97	14.94	16.52	19.80	13.10	15.89	18.11
Canada	4.15	4.70	5.05	5.46	5.48	6.26	7.27	5.81	6.76	8.04
Mexico and Chile	2.94	2.41	2.93	3.07	2.04	3.32	3.65	2.23	3.79	4.18
OECD Europe[2]	3.88	3.18	3.35	3.22	2.61	2.98	3.05	2.57	3.19	3.18
Japan and South Korea	0.18	0.17	0.17	0.16	0.19	0.18	0.18	0.20	0.18	0.19
Australia and New Zealand	0.49	0.55	0.60	0.62	0.53	0.86	0.89	0.50	0.96	1.01
Total OECD production	**24.29**	**27.18**	**29.03**	**31.51**	**25.79**	**30.12**	**34.84**	**24.41**	**30.77**	**34.70**
Non-OECD										
Russia	10.50	10.63	10.71	10.97	10.80	11.22	11.58	11.35	12.16	12.67
Other Europe and Eurasia[3]	3.27	3.42	3.41	3.87	4.21	4.42	4.99	4.83	5.18	6.44
China	4.48	4.80	5.11	5.23	5.16	5.66	6.18	5.18	5.84	7.54
Other Asia[4]	3.82	3.72	3.85	3.80	3.54	3.67	3.80	3.73	4.01	4.06
Middle East	1.20	1.02	1.03	1.14	0.75	0.85	1.04	0.56	0.77	0.98
Africa	2.41	2.73	2.70	2.79	2.90	2.94	2.92	3.23	3.33	3.39
Brazil	2.73	3.62	3.70	4.01	4.68	5.43	6.05	4.96	6.12	8.34
Other Central and South America	2.21	2.51	2.71	2.59	2.53	2.97	3.25	3.13	3.47	4.70
Total non-OECD production	**30.63**	**32.44**	**33.21**	**34.41**	**34.57**	**37.17**	**39.80**	**36.96**	**40.88**	**48.10**
Total petroleum and other liquids production	**91.4**	**100.2**	**98.4**	**95.7**	**111.9**	**108.8**	**107.7**	**124.7**	**121.1**	**123.7**
OPEC market share (percent)	39.9	40.5	36.7	31.1	46.1	38.2	30.7	50.8	40.8	33.0

Table C6. International petroleum and other liquids supply, disposition, and prices (continued)
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	2013	Projections								
		2020			2030			2040		
		Low oil price	Reference	High oil price	Low oil price	Reference	High oil price	Low oil price	Reference	High oil price
Selected world production subtotals:										
Crude oil and equivalents[6]	77.93	83.98	82.19	78.67	93.74	89.77	87.00	105.09	99.09	98.87
Tight oil	3.62	5.71	7.49	9.28	5.21	9.16	11.15	4.51	10.15	12.10
Bitumen[7]	2.11	2.91	3.00	3.31	3.57	3.95	4.72	3.86	4.26	5.36
Refinery processing gain[8]	2.40	2.45	2.42	2.26	2.80	2.74	2.50	3.20	2.97	2.89
Natural gas plant liquids	9.36	11.33	11.28	12.06	12.34	12.42	13.52	12.99	13.79	14.58
Liquids from renewable sources[9]	2.14	2.48	2.56	2.45	3.05	3.36	3.06	3.49	4.22	3.63
Liquids from coal[10]	0.21	0.30	0.33	0.53	0.30	0.69	1.40	0.30	1.05	3.16
Liquids from natural gas[11]	0.24	0.32	0.33	0.33	0.32	0.51	0.64	0.32	0.61	1.19
Liquids from kerogen[12]	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.01	0.01
Crude oil production[6]										
OPEC[5]										
Middle East	23.13	24.34	21.20	15.81	32.25	25.59	17.88	41.61	31.79	24.68
North Africa	2.43	3.19	2.93	2.63	3.61	2.92	2.65	4.06	2.96	2.71
West Africa	4.20	5.37	4.89	4.28	6.69	5.13	4.63	7.35	5.29	4.82
South America	2.82	3.34	2.86	2.54	4.23	2.98	2.55	5.25	3.48	2.80
Total OPEC production	**32.60**	**36.25**	**31.89**	**25.25**	**46.79**	**36.62**	**27.72**	**58.27**	**43.52**	**35.03**
Non-OPEC										
OECD										
United States (50 states)	8.90	10.93	11.58	13.36	9.63	11.01	13.47	8.09	10.41	10.94
Canada	3.42	4.01	4.35	4.76	4.76	5.48	6.50	5.08	5.92	7.24
Mexico and Chile	2.59	2.06	2.61	2.72	1.70	3.00	3.31	1.89	3.45	3.83
OECD Europe[2]	2.82	2.09	2.17	2.11	1.44	1.66	1.87	1.29	1.69	1.91
Japan and South Korea	0.00	0.00	0.00	0.01	0.00	0.00	0.01	0.00	0.00	0.01
Australia and New Zealand	0.37	0.42	0.47	0.48	0.40	0.67	0.73	0.36	0.75	0.84
Total OECD production	**18.10**	**19.51**	**21.18**	**23.44**	**17.93**	**21.83**	**25.88**	**16.72**	**22.23**	**24.77**
Non-OECD										
Russia	10.02	10.03	10.15	10.38	9.95	10.42	10.72	10.07	11.10	11.37
Other Europe and Eurasia[3]	3.05	3.13	3.18	3.57	3.77	4.03	4.52	4.16	4.66	5.73
China	4.16	4.23	4.54	4.58	4.27	4.56	4.70	4.04	4.13	4.53
Other Asia[4]	3.04	2.81	2.94	2.89	2.46	2.45	2.64	2.41	2.47	2.66
Middle East	1.16	0.98	1.00	1.10	0.71	0.82	1.00	0.52	0.74	0.94
Africa	1.97	2.23	2.18	2.19	2.38	2.38	2.26	2.71	2.70	2.71
Brazil	2.02	2.75	2.87	3.14	3.42	4.16	4.78	3.55	4.60	6.93
Other Central and South America	1.81	2.06	2.25	2.14	2.05	2.49	2.77	2.65	2.94	4.21
Total non-OECD production	**27.24**	**28.22**	**29.11**	**29.98**	**29.03**	**31.32**	**33.40**	**30.10**	**33.35**	**39.07**
Total crude oil production[6]	**77.9**	**84.0**	**82.2**	**78.7**	**93.7**	**89.8**	**87.0**	**105.1**	**99.1**	**98.9**
OPEC market share (percent)	41.8	43.2	38.8	32.1	49.9	40.8	31.9	55.4	43.9	35.4

[1]Estimated consumption. Includes both OPEC and non-OPEC consumers in the regional breakdown.
[2]OECD Europe = Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.
[3]Other Europe and Eurasia = Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Georgia, Kazakhstan, Kosovo, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Serbia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.
[4]Other Asia = Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), Fiji, French Polynesia, Guam, Hong Kong, India (for production), Indonesia, Kiribati, Laos, Malaysia, Macau, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, and Vietnam.
[5]OPEC = Organization of the Petroleum Exporting Countries = Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[6]Includes crude oil, lease condensate, tight oil (shale oil), extra-heavy oil, and bitumen (oil sands).
[7]Includes diluted and upgraded/synthetic bitumen (syncrude).
[8]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[9]Includes liquids produced from energy crops.
[10]Includes liquids converted from coal via the Fischer-Tropsch coal-to-liquids process.
[11]Includes liquids converted from natural gas via the Fischer-Tropsch natural-gas-to-liquids process.
[12]Includes liquids produced from kerogen (oil shale, not to be confused with tight oil (shale oil)).
OECD = Organization for Economic Cooperation and Development.
Note: Totals may not equal sum of components due to independent rounding. Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 Brent and West Texas Intermediate crude oil spot prices: Thomson Reuters. **2013 quantities and projections:** Energy Information Administration (EIA), AEO2015 National Energy Modeling System runs LOWPRICE.D021915A, REF2015.D021915A, and HIGHPRICE.D021915A; and EIA, Generate World Oil Balance application.

Appendix D

High oil and gas resource case comparisons

Table D1. Total energy supply, disposition, and price summary
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Production							
Crude oil and lease condensate	15.6	22.2	26.3	21.1	32.6	19.9	34.6
Natural gas plant liquids	3.6	5.5	6.3	5.7	7.9	5.5	9.0
Dry natural gas	25.1	29.6	33.1	33.9	43.8	36.4	52.0
Coal[1]	*20.0*	*21.7*	*18.8*	*22.5*	*19.8*	*22.6*	*20.3*
Nuclear / uranium[2]	8.3	8.4	8.4	8.5	8.5	8.7	8.5
Conventional hydroelectric power	2.5	2.8	2.8	2.8	2.8	2.8	2.8
Biomass[3]	4.2	4.4	4.5	4.6	4.7	5.0	5.1
Other renewable energy[4]	2.3	3.2	3.2	3.6	3.4	4.6	3.6
Other[5]	*1.3*	*0.9*	*0.9*	*0.9*	*1.0*	*1.0*	*1.0*
Total	**82.7**	**98.7**	**104.3**	**103.7**	**124.4**	**106.6**	**136.8**
Imports							
Crude oil	17.0	13.6	13.5	15.7	11.7	18.2	11.3
Petroleum and other liquids[6]	*4.3*	*4.6*	*4.4*	*4.4*	*4.7*	*4.1*	*4.4*
Natural gas[7]	2.9	1.9	1.8	1.6	1.7	1.7	2.5
Other imports[8]	0.3	0.1	0.1	0.1	0.1	0.1	0.0
Total	**24.5**	**20.2**	**19.9**	**21.7**	**18.2**	**24.1**	**18.3**
Exports							
Petroleum and other liquids[9]	7.3	11.2	15.4	12.6	21.6	13.7	24.3
Natural gas[10]	1.6	4.5	4.6	6.4	10.8	7.4	15.7
Coal	2.9	2.5	2.5	3.3	3.4	3.5	4.0
Total	**11.7**	**18.1**	**22.5**	**22.4**	**35.7**	**24.6**	**44.0**
Discrepancy[11]	**-1.6**	**-0.1**	**-0.1**	**0.2**	**0.1**	**0.3**	**0.3**
Consumption							
Petroleum and other liquids[12]	35.9	37.1	37.5	36.5	37.8	36.2	37.5
Natural gas	26.9	26.8	30.1	28.8	34.4	30.5	38.4
Coal[13]	18.0	19.2	16.3	19.2	16.3	19.0	16.3
Nuclear / uranium[2]	8.3	8.4	8.4	8.5	8.5	8.7	8.5
Conventional hydroelectric power	2.5	2.8	2.8	2.8	2.8	2.8	2.8
Biomass[14]	2.9	3.0	3.1	3.2	3.3	3.5	3.5
Other renewable energy[4]	2.3	3.2	3.2	3.6	3.4	4.6	3.6
Other[15]	0.4	0.3	0.3	0.3	0.3	0.3	0.3
Total	**97.1**	**100.8**	**101.8**	**102.9**	**106.8**	**105.7**	**110.8**
Prices (2013 dollars per unit)							
Crude oil spot prices (dollars per barrel)							
Brent	109	79	76	106	98	141	129
West Texas Intermediate	98	73	64	99	84	136	115
Natural gas at Henry Hub							
(dollars per million Btu)	3.73	4.88	3.12	5.69	3.67	7.85	4.38
Coal (dollars per ton)							
at the minemouth[16]	37.2	37.9	37.2	43.7	42.3	49.2	47.8
Coal (dollars per million Btu)							
at the minemouth[16]	*1.84*	*1.88*	*1.84*	*2.18*	*2.10*	*2.44*	*2.36*
Average end-use[17]	2.50	2.54	2.43	2.84	2.66	3.09	2.88
Average electricity (cents per kilowatthour)	10.1	10.5	10.0	11.1	10.0	11.8	10.3

Table D1. Total energy supply, disposition, and price summary (continued)
(quadrillion Btu per year, unless otherwise noted)

Supply, disposition, and prices	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Prices (nominal dollars per unit)							
Crude oil spot prices (dollars per barrel)							
Brent	109	90	85	142	127	229	205
West Texas Intermediate	98	83	72	133	109	220	182
Natural gas at Henry Hub (dollars per million Btu)	3.73	5.54	3.51	7.63	4.76	12.73	6.93
Coal (dollars per ton) at the minemouth[15]	37.2	43.0	41.7	58.6	54.8	79.8	75.6
Coal (dollars per million Btu)							
at the minemouth[16]	1.84	2.14	2.07	2.92	2.72	3.96	3.73
Average end-use[17]	2.50	2.88	2.73	3.81	3.45	5.00	4.56
Average electricity (cents per kilowatthour)	10.1	11.9	11.2	14.8	13.0	19.2	16.2

[1]Includes waste coal.
[2]These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.
[3]Includes grid-connected electricity from wood and wood waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[4]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy data.
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes imports of liquefied natural gas that are later re-exported.
[8]Includes coal, coal coke (net), and electricity (net). Excludes imports of fuel used in nuclear power plants.
[9]Includes crude oil, petroleum products, ethanol, and biodiesel.
[10]Includes re-exported liquefied natural gas.
[11]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[12]Estimated consumption. Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are hydrocarbon gas liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[13]Excludes coal converted to coal-based synthetic liquids and natural gas.
[14]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[15]Includes non-biogenic municipal waste, liquid hydrogen, and net electricity imports.
[16]Includes reported prices for both open market and captive mines. Prices weighted by production, which differs from average minemouth prices published in EIA data reports where it is weighted by reported sales.
[17]Prices weighted by consumption; weighted average excludes export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 natural gas supply values: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). 2013 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2013*, DOE/EIA-0584(2013) (Washington, DC, January 2015). 2013 petroleum supply values: EIA, *Petroleum Supply Annual 2013*, DOE/EIA-0340(2013)/1 (Washington, DC, September 2014). 2013 crude oil spot prices and natural gas spot price at Henry Hub: Thomson Reuters. Other 2013 coal values: *Quarterly Coal Report, October-December 2013*, DOE/EIA-0121(2013/4Q) (Washington, DC, March 2014). Other 2013 values: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). **Projections:** EIA, AEO2015 National Energy Modeling System runs REF2015.D021915A and HIGHRESOURCE.D021915B.

Table D2. Energy consumption by sector and source
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Energy consumption							
Residential							
Propane	0.43	0.32	0.33	0.28	0.28	0.25	0.25
Kerosene	0.01	0.01	0.01	0.01	0.01	0.00	0.00
Distillate fuel oil	0.50	0.40	0.40	0.31	0.31	0.24	0.24
Petroleum and other liquids subtotal	0.93	0.73	0.74	0.59	0.60	0.49	0.49
Natural gas	5.05	4.63	4.75	4.52	4.70	4.31	4.52
Renewable energy[1]	0.58	0.41	0.41	0.38	0.37	0.35	0.35
Electricity	4.75	4.86	4.90	5.08	5.20	5.42	5.61
Delivered energy	**11.32**	**10.63**	**10.80**	**10.57**	**10.86**	**10.57**	**10.97**
Electricity related losses	9.79	9.75	9.53	9.91	9.76	10.33	10.20
Total	**21.10**	**20.38**	**20.33**	**20.48**	**20.62**	**20.91**	**21.17**
Commercial							
Propane	0.15	0.16	0.16	0.17	0.17	0.18	0.18
Motor gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.06	0.06
Kerosene	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distillate fuel oil	0.37	0.34	0.34	0.30	0.31	0.27	0.28
Residual fuel oil	0.03	0.07	0.07	0.07	0.07	0.06	0.07
Petroleum and other liquids subtotal	0.59	0.62	0.63	0.60	0.61	0.58	0.59
Natural gas	3.37	3.30	3.49	3.43	3.71	3.71	4.11
Coal	0.04	0.05	0.05	0.05	0.05	0.05	0.05
Renewable energy[3]	0.12	0.12	0.12	0.12	0.12	0.12	0.12
Electricity	4.57	4.82	4.85	5.19	5.32	5.66	5.85
Delivered energy	**8.69**	**8.90**	**9.14**	**9.38**	**9.81**	**10.12**	**10.72**
Electricity related losses	9.42	9.68	9.44	10.13	9.99	10.80	10.64
Total	**18.10**	**18.58**	**18.58**	**19.52**	**19.81**	**20.92**	**21.37**
Industrial[4]							
Liquefied petroleum gases and other[5]	2.51	3.20	3.26	3.72	3.81	3.67	3.82
Motor gasoline[2]	0.25	0.26	0.27	0.25	0.29	0.25	0.29
Distillate fuel oil	1.31	1.42	1.41	1.36	1.46	1.35	1.48
Residual fuel oil	0.06	0.10	0.10	0.13	0.12	0.13	0.11
Petrochemical feedstocks	0.74	0.95	0.95	1.14	1.14	1.20	1.12
Other petroleum[6]	3.52	3.67	3.94	3.83	4.28	3.99	4.46
Petroleum and other liquids subtotal	8.40	9.61	9.94	10.44	11.09	10.59	11.29
Natural gas	7.62	8.33	8.56	8.65	9.17	8.90	9.43
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[7]	1.52	1.87	2.02	2.10	3.05	2.29	3.84
Natural gas subtotal	9.14	10.20	10.58	10.75	12.21	11.19	13.28
Metallurgical coal	0.62	0.61	0.59	0.56	0.59	0.51	0.53
Other industrial coal	0.88	0.93	0.93	0.96	0.97	0.99	1.01
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net coal coke imports	-0.02	0.00	0.00	-0.03	-0.03	-0.06	-0.06
Coal subtotal	1.48	1.54	1.52	1.48	1.53	1.44	1.48
Biofuels heat and coproducts	0.72	0.80	0.81	0.80	0.82	0.86	0.88
Renewable energy[8]	1.48	1.53	1.56	1.59	1.64	1.63	1.70
Electricity	3.26	3.74	3.83	4.04	4.27	4.12	4.35
Delivered energy	**24.48**	**27.42**	**28.24**	**29.10**	**31.55**	**29.82**	**32.98**
Electricity related losses	6.72	7.51	7.45	7.88	8.01	7.85	7.92
Total	**31.20**	**34.93**	**35.69**	**36.98**	**39.56**	**37.68**	**40.90**

Table D2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Transportation							
Propane	0.05	0.04	0.04	0.05	0.05	0.07	0.07
Motor gasoline[2]	15.94	15.35	15.42	13.30	13.56	12.55	12.83
of which: E85[9]	0.02	0.03	0.03	0.20	0.17	0.28	0.28
Jet fuel[10]	2.80	3.01	3.01	3.40	3.42	3.64	3.65
Distillate fuel oil[11]	6.50	7.35	7.42	7.76	8.22	7.97	8.33
Residual fuel oil	0.57	0.35	0.35	0.36	0.36	0.36	0.36
Other petroleum[12]	0.15	0.16	0.16	0.16	0.16	0.16	0.16
Petroleum and other liquids subtotal	26.00	26.27	26.42	25.03	25.77	24.76	25.42
Pipeline fuel natural gas	0.88	0.85	0.93	0.94	1.13	0.96	1.26
Compressed / liquefied natural gas	0.05	0.07	0.07	0.17	0.18	0.71	0.96
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.04	0.04	0.06	0.06
Delivered energy	**26.96**	**27.22**	**27.44**	**26.18**	**27.12**	**26.49**	**27.70**
Electricity related losses	0.05	0.06	0.06	0.08	0.08	0.12	0.11
Total	**27.01**	**27.29**	**27.50**	**26.27**	**27.20**	**26.61**	**27.81**
Unspecified sector[13]	**-0.27**	**-0.34**	**-0.34**	**-0.37**	**-0.41**	**-0.38**	**-0.41**
Delivered energy consumption for all sectors							
Liquefied petroleum gases and other[5]	3.14	3.73	3.80	4.23	4.31	4.17	4.33
Motor gasoline[2]	16.36	15.79	15.87	13.72	14.01	12.96	13.28
of which: E85[9]	0.02	0.03	0.03	0.20	0.17	0.28	0.28
Jet fuel[10]	2.97	3.20	3.20	3.61	3.63	3.86	3.88
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	8.10	8.86	8.92	9.05	9.57	9.13	9.60
Residual fuel oil	0.65	0.53	0.53	0.56	0.55	0.56	0.54
Petrochemical feedstocks	0.74	0.95	0.95	1.14	1.14	1.20	1.12
Other petroleum[14]	3.67	3.82	4.10	3.98	4.44	4.15	4.62
Petroleum and other liquids subtotal	35.65	36.89	37.38	36.30	37.66	36.03	37.38
Natural gas	16.10	16.32	16.86	16.76	17.75	17.64	19.03
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[7]	1.52	1.87	2.02	2.10	3.05	2.29	3.84
Pipeline natural gas	0.88	0.85	0.93	0.94	1.13	0.96	1.26
Natural gas subtotal	18.50	19.05	19.81	19.80	21.93	20.88	24.13
Metallurgical coal	0.62	0.61	0.59	0.56	0.59	0.51	0.53
Other coal	0.92	0.98	0.98	1.00	1.01	1.04	1.05
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net coal coke imports	-0.02	0.00	0.00	-0.03	-0.03	-0.06	-0.06
Coal subtotal	1.52	1.59	1.57	1.53	1.57	1.49	1.53
Biofuels heat and coproducts	0.72	0.80	0.81	0.80	0.82	0.86	0.88
Renewable energy[15]	2.18	2.06	2.09	2.09	2.13	2.10	2.17
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	12.60	13.45	13.62	14.35	14.83	15.25	15.87
Delivered energy	**71.17**	**73.84**	**75.27**	**74.87**	**78.94**	**76.62**	**81.97**
Electricity related losses	25.97	27.00	26.48	28.01	27.83	29.10	28.87
Total	**97.14**	**100.84**	**101.75**	**102.87**	**106.78**	**105.73**	**110.84**
Electric power[16]							
Distillate fuel oil	0.05	0.09	0.08	0.08	0.07	0.08	0.07
Residual fuel oil	0.21	0.08	0.09	0.09	0.09	0.09	0.10
Petroleum and other liquids subtotal	0.26	0.17	0.16	0.17	0.16	0.18	0.17
Natural gas	8.36	7.80	10.29	9.03	12.46	9.61	14.24
Steam coal	16.49	17.59	14.77	17.63	14.78	17.52	14.76
Nuclear / uranium[17]	8.27	8.42	8.42	8.47	8.46	8.73	8.46
Renewable energy[18]	4.78	6.13	6.11	6.72	6.50	7.99	6.82
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Electricity imports	0.18	0.11	0.11	0.10	0.08	0.11	0.07
Total	**38.57**	**40.45**	**40.10**	**42.35**	**42.67**	**44.36**	**44.74**

Table D2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and source	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Total energy consumption							
Liquefied petroleum gases and other[5]	3.14	3.73	3.80	4.23	4.31	4.17	4.33
Motor gasoline[2]	16.36	15.79	15.87	13.72	14.01	12.96	13.28
of which: E85[9]	0.02	0.03	0.03	0.20	0.17	0.28	0.28
Jet fuel[10]	2.97	3.20	3.20	3.61	3.63	3.86	3.88
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate fuel oil	8.15	8.95	9.00	9.13	9.65	9.21	9.67
Residual fuel oil	*0.87*	*0.61*	*0.61*	*0.64*	*0.64*	*0.65*	*0.64*
Petrochemical feedstocks	0.74	0.95	0.95	1.14	1.14	1.20	1.12
Other petroleum[14]	3.67	3.82	4.10	3.98	4.44	4.15	4.62
Petroleum and other liquids subtotal	35.91	37.06	37.54	36.47	37.82	36.21	37.54
Natural gas	24.46	24.12	27.15	25.79	30.21	27.25	33.27
Natural-gas-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and plant fuel[7]	1.52	1.87	2.02	2.10	3.05	2.29	3.84
Pipeline natural gas	0.88	0.85	0.93	0.94	1.13	0.96	1.26
Natural gas subtotal	26.86	26.85	30.10	28.83	34.39	30.50	38.37
Metallurgical coal	*0.62*	*0.61*	*0.59*	*0.56*	*0.59*	*0.51*	*0.53*
Other coal	17.41	18.57	15.75	18.63	15.79	18.56	15.81
Coal-to-liquids heat and power	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Net coal coke imports	-0.02	0.00	0.00	-0.03	-0.03	-0.06	-0.06
Coal subtotal	18.01	19.18	16.34	19.16	16.35	19.01	16.29
Nuclear / uranium[17]	8.27	8.42	8.42	8.47	8.46	8.73	8.46
Biofuels heat and coproducts	0.72	0.80	0.81	0.80	0.82	0.86	0.88
Renewable energy[19]	6.96	8.19	8.20	8.81	8.63	10.09	8.99
Liquid hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Non-biogenic municipal waste	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Electricity imports	0.18	0.11	0.11	0.10	0.08	0.11	0.07
Total	**97.14**	**100.84**	**101.75**	**102.87**	**106.78**	**105.73**	**110.84**
Energy use and related statistics							
Delivered energy use	71.17	73.84	75.27	74.87	78.94	76.62	81.97
Total energy use	97.14	100.84	101.75	102.87	106.78	105.73	110.84
Ethanol consumed in motor gasoline and E85	1.12	1.12	1.13	1.12	1.13	1.27	1.30
Population (millions)	317	334	334	359	359	380	380
Gross domestic product (billion 2009 dollars)	15,710	18,801	18,841	23,894	24,222	29,898	30,236
Carbon dioxide emissions (million metric tons)	5,405	5,499	5,435	5,514	5,636	5,549	5,800

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal water heating, and electricity generation from wind and solar photovoltaic sources.
[2]Includes ethanol and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal water heating and electricity generation from wind and solar photovoltaic sources.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[5]Includes ethane, natural gasoline, and refinery olefins.
[6]*Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.*
[7]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[8]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol in motor gasoline.
[9]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[10]Includes only kerosene type.
[11]Diesel fuel for on- and off- road use.
[12]Includes aviation gasoline and lubricants.
[13]Represents consumption unattributed to the sectors above.
[14]Includes aviation gasoline, petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[15]Includes electricity generated for sale to the grid and for own use from renewable sources, and non-electric energy from renewable sources. Excludes ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
[16]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[17]*These values represent the energy obtained from uranium when it is used in light water reactors. The total energy content of uranium is much larger, but alternative processes are required to take advantage of it.*
[18]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes net electricity imports.
[19]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic, and solar thermal sources. Excludes ethanol, net electricity imports, and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal water heaters.
Btu = British thermal unit.
Note: Includes estimated consumption for petroleum and other liquids. Totals may not equal sum of components due to independent rounding. Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 consumption based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE-EIA-0035(2014/11) (Washington, DC, November 2014). 2013 population and gross domestic product: IHS Economics, Industry and Employment models, November 2014. 2013 carbon dioxide emissions and emission factors: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). **Projections:** EIA, AEO2015 National Energy Modeling System runs REF2015.D021915A and HIGHRESOURCE.D021915B.

Table D3. Energy prices by sector and source
(2013 dollars per million Btu, unless otherwise noted)

Sector and source	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Residential							
Propane	23.3	23.0	22.2	24.4	23.9	26.6	25.6
Distillate fuel oil	27.2	21.5	20.9	26.3	24.9	32.9	31.3
Natural gas	10.0	11.6	9.6	12.8	10.4	15.5	11.9
Electricity	35.6	37.8	36.1	40.0	36.9	42.4	37.6
Commercial							
Propane	20.0	19.4	18.5	21.1	20.4	23.9	22.6
Distillate fuel oil	26.7	21.0	20.3	25.8	24.3	32.5	31.0
Residual fuel oil	22.1	14.2	13.5	18.1	16.7	24.3	22.1
Natural gas	8.1	9.6	7.6	10.4	8.1	12.6	9.0
Electricity	29.7	31.1	29.6	32.6	29.4	34.5	29.8
Industrial[1]							
Propane	20.3	19.6	18.7	21.5	20.8	24.5	23.0
Distillate fuel oil	27.3	21.2	20.5	26.1	24.5	32.7	31.3
Residual fuel oil	20.0	13.3	12.6	17.2	15.7	23.5	21.1
Natural gas[2]	4.6	6.2	4.3	6.8	4.6	8.8	5.2
Metallurgical coal	5.5	5.8	5.8	6.7	6.6	7.2	7.1
Other industrial coal	3.2	3.3	3.2	3.6	3.4	3.9	3.7
Coal to liquids	- -	- -	- -	- -	- -	- -	- -
Electricity	20.2	21.3	19.9	22.6	20.0	24.7	20.7
Transportation							
Propane	24.6	24.0	23.3	25.5	24.9	27.6	26.6
E85[3]	33.1	30.4	29.9	31.2	30.2	35.4	34.5
Motor gasoline[4]	29.3	22.5	21.8	26.4	25.0	32.3	31.2
Jet fuel[5]	21.8	16.1	15.5	21.3	19.4	28.3	26.1
Diesel fuel (distillate fuel oil)[6]	28.2	23.1	22.5	28.0	26.4	34.7	33.2
Residual fuel oil	19.3	11.7	11.1	15.4	14.1	20.3	19.0
Natural gas[7]	17.6	17.8	16.0	15.7	13.9	19.6	16.8
Electricity	28.5	30.2	28.2	32.9	28.9	36.0	30.5
Electric power[8]							
Distillate fuel oil	24.0	18.8	18.1	23.6	22.1	30.2	28.7
Residual fuel oil	18.9	11.5	10.7	15.4	14.0	21.6	19.3
Natural gas	4.4	5.4	3.7	6.2	4.1	8.3	4.7
Steam coal	2.3	2.4	2.2	2.7	2.4	2.9	2.7
Average price to all users[9]							
Propane	21.9	21.1	20.2	22.6	21.9	25.2	23.9
E85[3]	33.1	30.4	29.9	31.2	30.2	35.4	34.5
Motor gasoline[4]	29.0	22.5	21.8	26.4	25.0	32.3	31.2
Jet fuel[5]	21.8	16.1	15.5	21.3	19.4	28.3	26.1
Distillate fuel oil	27.9	22.6	22.0	27.6	26.0	34.2	32.8
Residual fuel oil	19.4	12.2	11.6	16.0	14.7	21.5	19.8
Natural gas	6.1	7.5	5.4	8.2	5.8	10.5	6.7
Metallurgical coal	5.5	5.8	5.8	6.7	6.6	7.2	7.1
Other coal	2.4	2.4	2.3	2.7	2.5	3.0	2.7
Coal to liquids	- -	- -	- -	- -	- -	- -	- -
Electricity	29.5	30.8	29.2	32.4	29.3	34.7	30.1
Non-renewable energy expenditures by sector (billion 2013 dollars)							
Residential	243	254	238	276	256	311	278
Commercial	177	194	182	219	200	259	228
Industrial[1]	224	264	242	323	298	389	348
Transportation	719	565	550	638	619	791	781
Total non-renewable expenditures	1,364	1,276	1,213	1,456	1,373	1,751	1,635
Transportation renewable expenditures	1	1	1	6	5	10	10
Total expenditures	**1,364**	**1,277**	**1,214**	**1,462**	**1,378**	**1,761**	**1,645**

Table D3. Energy prices by sector and source (continued)

(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Residential							
Propane	23.3	26.1	25.0	32.8	31.0	43.1	40.4
Distillate fuel oil	27.2	24.4	23.4	35.3	32.3	53.3	49.5
Natural gas	10.0	13.2	10.8	17.1	13.5	25.1	18.8
Electricity	35.6	42.9	40.5	53.6	47.9	68.8	59.4
Commercial							
Propane	20.0	22.0	20.7	28.3	26.5	38.8	35.7
Distillate fuel oil	26.7	23.8	22.8	34.6	31.5	52.6	49.1
Residual fuel oil	22.1	16.1	15.1	24.3	21.7	39.4	34.9
Natural gas	8.1	10.8	8.5	13.9	10.5	20.5	14.2
Electricity	29.7	35.3	33.2	43.7	38.1	56.0	47.1
Industrial[1]							
Propane	20.3	22.3	21.0	28.8	26.9	39.7	36.4
Distillate fuel oil	27.3	24.1	23.0	35.0	31.8	53.0	49.4
Residual fuel oil	20.0	15.1	14.2	23.1	20.4	38.0	33.4
Natural gas[2]	4.6	7.0	4.8	9.1	6.0	14.2	8.3
Metallurgical coal	5.5	6.6	6.5	8.9	8.5	11.6	11.2
Other industrial coal	3.2	3.8	3.6	4.8	4.5	6.3	5.9
Coal to liquids	- -	- -	- -	- -	- -	- -	- -
Electricity	20.2	24.2	22.3	30.3	26.0	40.0	32.7
Transportation							
Propane	24.6	27.2	26.1	34.1	32.3	44.8	42.0
E85[3]	33.1	34.4	33.5	41.9	39.3	57.4	54.6
Motor gasoline[4]	29.3	25.5	24.5	35.3	32.4	52.4	49.4
Jet fuel[5]	21.8	18.3	17.3	28.6	25.2	45.8	41.2
Diesel fuel (distillate fuel oil)[6]	28.2	26.2	25.2	37.6	34.3	56.2	52.5
Residual fuel oil	19.3	13.2	12.4	20.6	18.4	32.9	30.1
Natural gas[7]	17.6	20.2	18.0	21.0	18.0	31.8	26.5
Electricity	28.5	34.3	31.7	44.1	37.5	58.4	48.2
Electric power[8]							
Distillate fuel oil	24.0	21.3	20.3	31.7	28.7	49.0	45.4
Residual fuel oil	18.9	13.0	12.0	20.6	18.2	35.0	30.6
Natural gas	4.4	6.1	4.1	8.3	5.4	13.4	7.4
Steam coal	2.3	2.7	2.5	3.6	3.2	4.7	4.2

Table D3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and source	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Average price to all users[9]							
Propane	21.9	23.9	22.6	30.3	28.4	40.9	37.7
E85[3]	33.1	34.4	33.5	41.9	39.3	57.4	54.6
Motor gasoline[4]	29.0	25.5	24.5	35.3	32.4	52.4	49.4
Jet fuel[5]	21.8	18.3	17.3	28.6	25.2	45.8	41.2
Distillate fuel oil	27.9	25.7	24.6	36.9	33.7	55.5	51.9
Residual fuel oil	19.4	13.8	13.0	21.5	19.1	34.8	31.2
Natural gas	6.1	8.5	6.1	11.0	7.5	17.0	10.6
Metallurgical coal	5.5	6.6	6.5	8.9	8.5	11.6	11.2
Other coal	2.4	2.8	2.6	3.7	3.3	4.8	4.3
Coal to liquids	- -	- -	- -	- -	- -	- -	- -
Electricity	29.5	34.9	32.8	43.4	38.1	56.2	47.5
Non-renewable energy expenditures by sector (billion nominal dollars)							
Residential	243	288	268	370	332	504	440
Commercial	177	220	205	294	260	420	360
Industrial[1]	224	299	272	433	387	631	551
Transportation	719	641	617	855	803	1,283	1,235
Total non-renewable expenditures	1,364	1,448	1,361	1,952	1,782	2,839	2,586
Transportation renewable expenditures	1	1	1	8	7	16	15
Total expenditures	**1,364**	**1,449**	**1,362**	**1,960**	**1,788**	**2,855**	**2,601**

[1]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[2]Excludes use for lease and plant fuel.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
[5]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Natural gas used as fuel in motor vehicles, trains, and ships. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[8]Includes electricity-only and combined heat and power plants that have a regulatory status.
[9]Weighted averages of end-use fuel prices are derived from the prices shown in each sector and the corresponding sectoral consumption.
Btu = British thermal unit.
- - = Not applicable.
Note: Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2014/08) (Washington, DC, August 2014). 2013 residential, commercial, and industrial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). 2013 transportation sector natural gas delivered prices are model results. 2013 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2013 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2013 and April 2014, Table 4.2, and EIA, *State Energy Data Report 2012*, DOE/EIA-0214(2012) (Washington, DC, June 2014). 2013 coal prices based on: EIA, *Quarterly Coal Report, October-December 2013*, DOE/EIA-0121(2013/4Q) (Washington, DC, March 2014) and EIA, AEO2015 National Energy Modeling System run REF2015.D021915A. 2013 electricity prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2013 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2015 National Energy Modeling System runs REF2015.D021915A and HIGHRESOURCE.D021915B.

Table D4. Petroleum and other liquids supply and disposition
(million barrels per day, unless otherwise noted)

Supply and disposition	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Crude oil							
Domestic crude production[1]	7.44	10.60	12.61	10.04	15.64	9.43	16.59
Alaska	0.52	0.42	0.42	0.24	0.24	0.34	0.14
Lower 48 states	6.92	10.18	12.19	9.80	15.40	9.09	16.45
Net imports	7.60	5.51	5.16	6.44	4.02	7.58	4.08
Gross imports	7.73	6.14	6.03	7.07	5.18	8.21	5.02
Exports	0.13	0.63	0.87	0.63	1.16	0.63	0.94
Other crude supply[2]	0.27	0.00	0.00	0.00	0.00	0.00	0.00
Total crude supply	**15.30**	**16.11**	**17.77**	**16.48**	**19.66**	**17.01**	**20.67**
Net product imports	-1.37	-2.80	-5.03	-3.56	-7.86	-4.26	-9.89
Gross refined product imports[3]	0.82	1.21	1.03	1.31	1.27	1.26	1.12
Unfinished oil imports	0.66	0.60	0.60	0.52	0.52	0.45	0.45
Blending component imports	0.60	0.59	0.58	0.49	0.57	0.40	0.52
Exports	3.43	5.20	7.24	5.89	10.22	6.36	11.97
Refinery processing gain[4]	1.09	0.98	1.14	0.97	1.10	0.98	1.06
Product stock withdrawal	0.11	0.00	0.00	0.00	0.00	0.00	0.00
Natural gas plant liquids	2.61	4.04	4.65	4.19	5.78	4.07	6.59
Supply from renewable sources	0.93	1.01	1.02	1.01	1.01	1.12	1.14
Ethanol	0.83	0.84	0.85	0.84	0.84	0.95	0.97
Domestic production	0.85	0.86	0.87	0.86	0.88	0.93	0.96
Net imports	-0.02	-0.02	-0.03	-0.02	-0.03	0.02	0.02
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Biodiesel	0.10	0.14	0.14	0.11	0.09	0.11	0.09
Domestic production	0.09	0.13	0.13	0.10	0.08	0.10	0.08
Net imports	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other biomass-derived liquids[5]	0.00	0.03	0.03	0.06	0.08	0.06	0.08
Domestic production	0.00	0.03	0.03	0.06	0.08	0.06	0.08
Net imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Stock withdrawal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquids from gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquids from coal	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other[6]	0.21	0.28	0.30	0.30	0.34	0.32	0.34
Total primary supply[7]	**18.87**	**19.62**	**19.84**	**19.38**	**20.03**	**19.24**	**19.90**
Product supplied							
by fuel							
Liquefied petroleum gases and other[8]	2.50	2.91	2.95	3.30	3.38	3.25	3.39
Motor gasoline[9]	8.85	8.49	8.53	7.41	7.56	7.05	7.22
of which: E85[10]	0.01	0.02	0.02	0.13	0.12	0.19	0.19
Jet fuel[11]	1.43	1.55	1.55	1.75	1.76	1.87	1.88
Distillate fuel oil[12]	3.83	4.26	4.28	4.34	4.59	4.38	4.60
of which: Diesel	3.56	3.94	3.97	4.09	4.33	4.17	4.38
Residual fuel oil	0.32	0.27	0.27	0.28	0.28	0.28	0.28
Other[13]	2.04	2.18	2.29	2.33	2.53	2.43	2.60
by sector							
Residential and commercial	0.86	0.76	0.76	0.67	0.68	0.61	0.62
Industrial[14]	4.69	5.50	5.65	6.04	6.37	6.09	6.47
Transportation	13.36	13.46	13.54	12.79	13.15	12.66	13.00
Electric power[15]	0.12	0.08	0.07	0.08	0.07	0.08	0.08
Unspecified sector[16]	-0.12	-0.15	-0.15	-0.17	-0.19	-0.17	-0.19
Total product supplied	**18.96**	**19.65**	**19.87**	**19.41**	**20.09**	**19.27**	**19.97**
Discrepancy[17]	-0.10	-0.03	-0.03	-0.03	-0.06	-0.03	-0.07

Table D4. Petroleum and other liquids supply and disposition (continued)

(million barrels per day, unless otherwise noted)

Supply and disposition	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Domestic refinery distillation capacity[18]	17.8	18.8	19.0	18.8	20.1	18.8	20.9
Capacity utilization rate (percent)[19]	88.3	87.8	95.6	89.4	99.8	92.0	100.4
Net import share of product supplied (percent)	33.0	13.7	0.6	14.8	-19.3	17.4	-29.1
Net expenditures for imported crude oil and petroleum products (billion 2013 dollars)	308	167	153	259	165	405	214

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude oil stock withdrawals.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes pyrolysis oils, biomass-derived Fischer-Tropsch liquids, biobutanol, and renewable feedstocks used for the on-site production of diesel and gasoline.
[6]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[7]Total crude supply, net product imports, refinery processing gain, product stock withdrawal, natural gas plant liquids, supply from renewable sources, liquids from gas, liquids from coal, and other supply.
[8]Includes ethane, natural gasoline, and refinery olefins.
[9]Includes ethanol and ethers blended into gasoline.
[10]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[11]Includes only kerosene type.
[12]Includes distillate fuel oil from petroleum and biomass feedstocks.
[13]Includes kerosene, aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, and miscellaneous petroleum products.
[14]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[15]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[16]Represents consumption unattributed to the sectors above.
[17]Balancing item. Includes unaccounted for supply, losses, and gains.
[18]End-of-year operable capacity.
[19]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
Note: Totals may not equal sum of components due to independent rounding. Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 product supplied based on: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). Other 2013 data: EIA, *Petroleum Supply Annual 2013*, DOE/EIA-0340(2013)/1 (Washington, DC, September 2014). **Projections:** EIA, AEO2015 National Energy Modeling System runs REF2015.D021915A and HIGHRESOURCE.D021915B.

Table D5. Petroleum and other liquids prices
(2013 dollars per gallon, unless otherwise noted)

Sector and fuel	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Crude oil prices (2013 dollars per barrel)							
Brent spot	109	79	76	106	98	141	129
West Texas Intermediate spot	98	73	64	99	84	136	115
Average imported refiners acquisition cost[1]	98	71	66	96	82	131	111
Brent / West Texas Intermediate spread	10.7	6.2	11.3	6.2	14.1	5.6	14.1
Delivered sector product prices							
Residential							
Propane	2.13	2.10	2.03	2.23	2.18	2.43	2.33
Distillate fuel oil	3.78	2.99	2.89	3.65	3.45	4.56	4.34
Commercial							
Distillate fuel oil	3.68	2.89	2.80	3.56	3.35	4.47	4.28
Residual fuel oil	3.31	2.12	2.02	2.71	2.50	3.64	3.31
Residual fuel oil (2013 dollars per barrel)	139	89	85	114	105	153	139
Industrial[2]							
Propane	1.85	1.79	1.70	1.96	1.90	2.24	2.10
Distillate fuel oil	3.75	2.91	2.82	3.58	3.36	4.49	4.29
Residual fuel oil	3.00	2.00	1.89	2.58	2.36	3.51	3.16
Residual fuel oil (2013 dollars per barrel)	126	84	79	108	99	147	133
Transportation							
Propane	2.24	2.19	2.12	2.32	2.27	2.52	2.43
E85[3]	3.14	2.90	2.85	2.98	2.88	3.38	3.29
Ethanol wholesale price	2.37	2.49	2.42	2.35	2.28	2.64	2.53
Motor gasoline[4]	3.55	2.74	2.65	3.20	3.03	3.90	3.77
Jet fuel[5]	2.94	2.17	2.09	2.88	2.62	3.81	3.52
Diesel fuel (distillate fuel oil)[6]	3.86	3.17	3.08	3.84	3.62	4.75	4.55
Residual fuel oil	2.89	1.74	1.66	2.30	2.12	3.03	2.85
Residual fuel oil (2013 dollars per barrel)	122	73	70	97	89	127	120
Electric power[7]							
Distillate fuel oil	3.33	2.60	2.51	3.28	3.07	4.19	3.98
Residual fuel oil	2.83	1.71	1.61	2.30	2.09	3.23	2.90
Residual fuel oil (2013 dollars per barrel)	119	72	67	97	88	136	122
Average prices, all sectors[8]							
Propane	2.00	1.93	1.84	2.06	2.00	2.30	2.18
Motor gasoline[4]	3.53	2.74	2.65	3.20	3.03	3.90	3.77
Jet fuel[5]	2.94	2.17	2.09	2.88	2.62	3.81	3.52
Distillate fuel oil	3.83	3.11	3.01	3.78	3.57	4.69	4.50
Residual fuel oil	2.90	1.83	1.73	2.40	2.20	3.22	2.96
Residual fuel oil (2013 dollars per barrel)	122	77	73	101	92	135	124
Average	**3.16**	**2.46**	**2.37**	**2.89**	**2.73**	**3.62**	**3.44**

Table D5. Petroleum and other liquids prices (continued)
(nominal dollars per gallon, unless otherwise noted)

Sector and fuel	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Crude oil prices (nominal dollars per barrel)							
Brent spot	109	90	85	142	127	229	205
West Texas Intermediate spot	98	83	72	133	109	220	182
Average imported refiners acquisition cost[1]	98	80	74	129	107	212	175
Delivered sector product prices							
Residential							
Propane	2.13	2.38	2.28	2.99	2.83	3.94	3.69
Distillate fuel oil	3.78	3.39	3.25	4.90	4.48	7.40	6.87
Commercial							
Distillate fuel oil	3.68	3.28	3.14	4.78	4.35	7.25	6.76
Residual fuel oil	3.31	2.41	2.26	3.63	3.25	5.90	5.23
Industrial[2]							
Propane	1.85	2.04	1.91	2.63	2.46	3.62	3.33
Distillate fuel oil	3.75	3.30	3.16	4.80	4.37	7.28	6.78
Residual fuel oil	3.00	2.26	2.12	3.46	3.06	5.69	4.99
Transportation							
Propane	2.24	2.49	2.38	3.12	2.95	4.09	3.84
E85[3]	3.14	3.29	3.20	3.99	3.74	5.48	5.21
Ethanol wholesale price	2.37	2.83	2.72	3.15	2.96	4.27	4.00
Motor gasoline[4]	3.55	3.10	2.98	4.29	3.93	6.32	5.96
Jet fuel[5]	2.94	2.47	2.34	3.86	3.40	6.18	5.57
Diesel fuel (distillate fuel oil)[6]	3.86	3.60	3.45	5.15	4.70	7.70	7.20
Residual fuel oil	2.89	1.98	1.86	3.08	2.75	4.92	4.50
Electric power[7]							
Distillate fuel oil	3.33	2.95	2.82	4.39	3.98	6.79	6.30
Residual fuel oil	2.83	1.94	1.80	3.09	2.72	5.24	4.58
Average prices, all sectors[8]							
Propane	2.00	2.19	2.07	2.77	2.59	3.73	3.45
Motor gasoline[4]	3.53	3.10	2.98	4.29	3.93	6.32	5.95
Jet fuel[5]	2.94	2.47	2.34	3.86	3.40	6.18	5.57
Distillate fuel oil	3.83	3.52	3.38	5.07	4.63	7.61	7.12
Residual fuel oil (nominal dollars per barrel)	122	87	82	135	120	219	196
Average	**3.16**	**2.79**	**2.66**	**3.88**	**3.54**	**5.86**	**5.43**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes combined heat and power plants that have a non-regulatory status, and small on-site generating systems.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State, and local taxes.
[5]Includes only kerosene type.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Includes electricity-only and combined heat and power plants that have a regulatory status.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 Brent and West Texas Intermediate crude oil spot prices: Thomson Reuters. 2013 average imported crude oil price: Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2013 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Monthly*, DOE/EIA-0380(2014/08) (Washington, DC, August 2014). 2013 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2013 electric power prices based on: *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2013 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2013 wholesale ethanol prices derived from Bloomberg U.S. average rack price. **Projections:** EIA, AEO2015 National Energy Modeling System runs REF2015.D021915A and HIGHRESOURCE.D021915B.

Table D6. Natural gas supply, disposition, and prices
(trillion cubic feet, unless otherwise noted)

Supply, disposition, and prices	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Supply							
Dry gas production[1]	24.40	28.82	32.18	33.01	42.66	35.45	50.61
Supplemental natural gas[2]	0.05	0.06	0.06	0.06	0.06	0.06	0.06
Net imports	1.29	-2.55	-2.74	-4.81	-9.03	-5.62	-13.11
Pipeline[3]	1.20	-0.48	-0.66	-1.52	-1.78	-2.33	-2.85
Liquefied natural gas	0.09	-2.08	-2.08	-3.29	-7.26	-3.29	-10.26
Total supply	**25.75**	**26.33**	**29.51**	**28.27**	**33.69**	**29.90**	**37.57**
Consumption by sector							
Residential	4.92	4.50	4.62	4.40	4.57	4.20	4.40
Commercial	3.28	3.21	3.39	3.33	3.61	3.61	4.00
Industrial[4]	7.41	8.10	8.32	8.41	8.92	8.66	9.18
Natural gas-to-liquids heat and power[5]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural gas-to-liquids production[6]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electric power[7]	8.16	7.61	10.04	8.81	12.16	9.38	13.89
Transportation[8]	0.05	0.07	0.07	0.17	0.18	0.70	0.94
Pipeline fuel	0.86	0.83	0.90	0.91	1.10	0.93	1.22
Lease and plant fuel[9]	1.48	1.82	1.97	2.05	2.97	2.23	3.74
Total consumption	**26.16**	**26.14**	**29.32**	**28.08**	**33.50**	**29.70**	**37.38**
Discrepancy[10]	**-0.41**	**0.19**	**0.19**	**0.19**	**0.19**	**0.19**	**0.19**
Natural gas spot price at Henry Hub							
(2013 dollars per million Btu)	3.73	4.88	3.12	5.69	3.67	7.85	4.38
(nominal dollars per million Btu)	3.73	5.54	3.51	7.63	4.76	12.73	6.93
Delivered prices							
(2013 dollars per thousand cubic feet)							
Residential	10.29	11.92	9.90	13.15	10.72	15.90	12.21
Commercial	8.35	9.82	7.83	10.69	8.31	12.97	9.24
Industrial[4]	4.68	6.35	4.40	6.99	4.78	9.03	5.37
Electric power[7]	4.51	5.52	3.77	6.38	4.25	8.49	4.79
Transportation[11]	18.13	18.27	16.49	16.13	14.27	20.18	17.24
Average[12]	**6.32**	**7.66**	**5.59**	**8.40**	**5.97**	**10.76**	**6.87**
(nominal dollars per thousand cubic feet)							
Residential	10.29	13.52	11.11	17.62	13.91	25.77	19.31
Commercial	8.35	11.14	8.79	14.33	10.78	21.03	14.61
Industrial[4]	4.68	7.20	4.94	9.37	6.20	14.64	8.49
Electric power[7]	4.51	6.26	4.24	8.55	5.52	13.76	7.57
Transportation[11]	18.13	20.73	18.51	21.62	18.52	32.72	27.26
Average[12]	**6.32**	**8.68**	**6.28**	**11.27**	**7.75**	**17.44**	**10.87**

[1]Marketed production (wet) minus extraction losses.
[2]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.
[3]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida, as well as gas from Canada and Mexico.
[4]Includes energy for combined heat and power plants that have a non-regulatory status, and small on-site generating systems. Excludes use for lease and plant fuel.
[5]Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
[6]Includes any natural gas converted into liquid fuel.
[7]Includes consumption of energy by electricity-only and combined heat and power plants that have a regulatory status.
[8]Natural gas used as fuel in motor vehicles, trains, and ships.
[9]Represents natural gas used in well, field, and lease operations, in natural gas processing plant machinery, and for liquefaction in export facilities.
[10]Balancing item. Natural gas lost as a result of converting flow data measured at varying temperatures and pressures to a standard temperature and pressure and the merger of different data reporting systems which vary in scope, format, definition, and respondent type. In addition, 2013 values include net storage injections.
[11]Natural gas used as fuel in motor vehicles, trains, and ships. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[12]Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
- - = *Not applicable.*
Note: Totals may not equal sum of components due to independent rounding. Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 supply values; lease, plant, and pipeline fuel consumption; and residential, commercial, and industrial delivered prices: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). Other 2013 consumption based on: EIA, *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014). 2013 natural gas spot price at Henry Hub: Thomson Reuters. 2013 electric power prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2013 and April 2014, Table 4.2, and EIA, *State Energy Data Report 2012*, DOE/EIA-0214(2012) (Washington, DC, June 2014). 2013 transportation sector delivered prices are model results. **Projections:** EIA, AEO2015 National Energy Modeling System runs REF2015.D021915A and HIGHRESOURCE.D021915B.

Table D7. Oil and gas supply

Production and supply	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Crude oil							
Lower 48 average wellhead price[1]							
(2013 dollars per barrel)	**97**	**75**	**67**	**101**	**85**	**136**	**117**
Production (million barrels per day)[2]							
United States total	7.44	10.60	12.61	10.04	15.64	9.43	16.59
Lower 48 onshore	5.57	8.03	9.88	7.60	13.03	6.92	14.03
Tight oil[3]	3.15	5.60	7.45	4.83	10.23	4.29	11.56
Carbon dioxide enhanced oil recovery	0.28	0.35	0.32	0.58	0.46	0.83	0.44
Other	2.14	2.08	2.12	2.19	2.34	1.80	2.03
Lower 48 offshore	1.36	2.15	2.31	2.21	2.37	2.17	2.42
State	0.07	0.05	0.05	0.03	0.03	0.02	0.02
Federal	1.29	2.10	2.26	2.18	2.34	2.14	2.39
Alaska	0.52	0.42	0.42	0.24	0.24	0.34	0.14
Onshore	0.45	0.30	0.30	0.18	0.18	0.12	0.12
State offshore	0.06	0.12	0.12	0.06	0.06	0.02	0.02
Federal offshore	0.00	0.00	0.00	0.00	0.00	0.20	0.00
Lower 48 end of year reserves[2]							
(billion barrels)	**29.4**	**37.4**	**40.6**	**42.6**	**55.2**	**44.8**	**62.7**
Natural gas plant liquids production							
(million barrels per day)							
United States total	2.61	4.04	4.65	4.20	5.78	4.07	6.59
Lower 48 onshore	2.39	3.82	4.42	3.92	5.50	3.79	6.31
Lower 48 offshore	0.18	0.19	0.20	0.26	0.26	0.26	0.27
Alaska	0.03	0.02	0.02	0.01	0.01	0.02	0.01
Natural gas							
Natural gas spot price at Henry Hub							
(2013 dollars per million Btu)	**3.73**	**4.88**	**3.12**	**5.69**	**3.67**	**7.85**	**4.38**
Dry production (trillion cubic feet)[4]							
United States total	24.40	28.82	32.18	33.01	42.66	35.45	50.61
Lower 48 onshore	22.63	26.52	29.78	29.05	39.66	31.49	47.47
Tight gas	4.38	5.21	5.44	5.99	7.06	6.97	8.14
Shale gas and tight oil plays[3]	11.34	15.44	18.82	17.85	27.50	19.58	34.57
Coalbed methane	1.29	1.45	1.25	1.24	1.16	1.25	1.13
Other	5.61	4.42	4.27	3.97	3.95	3.69	3.63
Lower 48 offshore	1.46	2.03	2.14	2.79	2.77	2.81	2.95
State	0.11	0.06	0.06	0.03	0.03	0.02	0.02
Federal	1.35	1.98	2.08	2.76	2.74	2.79	2.93
Alaska	0.32	0.27	0.27	1.18	0.23	1.15	0.19
Onshore	0.32	0.27	0.27	1.18	0.23	1.15	0.19
State offshore	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Federal offshore	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lower 48 end of year dry reserves[4]							
(trillion cubic feet)	**293**	**309**	**329**	**329**	**382**	**345**	**435**
Supplemental gas supplies (trillion cubic feet)[5]	**0.05**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**
Total lower 48 wells drilled (thousands)	**44.5**	**43.4**	**47.1**	**52.1**	**62.3**	**56.7**	**61.5**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Tight oil represents resources in low-permeability reservoirs, including shale and chalk formations. The specific plays included in the tight oil category are Bakken/Three Forks/Sanish, Eagle Ford, Woodford, Austin Chalk, Spraberry, Niobrara, Avalon/Bone Springs, and Monterey.
[4]Marketed production (wet) minus extraction losses.
[5]Synthetic natural gas, propane air, coke oven gas, refinery gas, biomass gas, air injected for Btu stabilization, and manufactured gas commingled and distributed with natural gas.

Note: Totals may not equal sum of components due to independent rounding. Data for 2013 are model results and may differ from official EIA data reports.

Sources: 2013 crude oil lower 48 average wellhead price: U.S. Energy Information Administration (EIA), *Petroleum Marketing Monthly*, DOE/EIA-0380(2014/08) (Washington, DC, August 2014). 2013 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 2013*, DOE/EIA-0340(2013)/1 (Washington, DC, September 2014). 2013 natural gas spot price at Henry Hub: Thomson Reuters. 2013 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2014/07) (Washington, DC, July 2014). Other 2013 values: EIA, Office of Energy Analysis. **Projections:** EIA, AEO2015 National Energy Modeling System runs REF2015.D021915A and HIGHRESOURCE.D021915B.

Table D8. International petroleum and other liquids supply, disposition, and prices
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Crude oil spot prices							
(2013 dollars per barrel)							
Brent	109	79	76	106	98	141	129
West Texas Intermediate	98	73	64	99	84	136	115
(nominal dollars per barrel)							
Brent	109	90	85	142	127	229	205
West Texas Intermediate	98	83	72	133	109	220	182
Petroleum and other liquids consumption[1]							
OECD							
United States (50 states)	18.96	19.65	19.87	19.41	20.09	19.27	19.97
United States territories	0.30	0.31	0.31	0.34	0.34	0.38	0.38
Canada	2.29	2.31	2.31	2.21	2.21	2.14	2.14
Mexico and Chile	2.46	2.71	2.71	2.80	2.80	2.92	2.92
OECD Europe[2]	13.96	14.20	14.20	14.09	14.09	14.12	14.12
Japan	4.56	4.27	4.27	4.03	4.03	3.65	3.65
South Korea	2.43	2.58	2.58	2.53	2.53	2.40	2.40
Australia and New Zealand	1.16	1.16	1.16	1.11	1.11	1.15	1.15
Total OECD consumption	**46.14**	**47.20**	**47.43**	**46.52**	**47.20**	**46.04**	**46.74**
Non-OECD							
Russia	3.30	3.31	3.31	3.23	3.23	3.01	3.01
Other Europe and Eurasia[3]	2.06	2.22	2.22	2.39	2.39	2.59	2.59
China	10.67	13.13	13.13	17.03	17.03	20.19	20.19
India	3.70	4.30	4.30	5.52	5.52	6.79	6.79
Other Asia[4]	7.37	9.08	9.08	12.35	12.35	16.49	16.49
Middle East	7.61	8.40	8.40	9.56	9.56	11.13	11.13
Africa	3.42	3.93	3.93	4.78	4.78	6.18	6.18
Brazil	3.11	3.33	3.33	3.74	3.74	4.50	4.50
Other Central and South America	3.38	3.49	3.49	3.72	3.72	4.15	4.15
Total non-OECD consumption	**44.60**	**51.20**	**51.20**	**62.31**	**62.31**	**75.01**	**75.01**
Total consumption	**90.7**	**98.4**	**98.6**	**108.8**	**109.5**	**121.0**	**121.8**
Petroleum and other liquids production							
OPEC[5]							
Middle East	26.32	24.56	21.99	29.34	22.69	36.14	27.03
North Africa	2.90	3.51	3.51	3.67	3.67	4.06	4.06
West Africa	4.26	5.00	5.00	5.24	5.24	5.43	5.43
South America	3.01	3.10	3.10	3.27	3.27	3.79	3.79
Total OPEC production	**36.49**	**36.16**	**33.59**	**41.53**	**34.87**	**49.42**	**40.31**
Non-OPEC							
OECD							
United States (50 states)	12.64	16.92	19.73	16.52	23.89	15.89	25.69
Canada	4.15	5.05	5.05	6.26	6.26	6.76	6.76
Mexico and Chile	2.94	2.93	2.93	3.32	3.32	3.79	3.79
OECD Europe[2]	3.88	3.35	3.35	2.98	2.98	3.19	3.19
Japan and South Korea	0.18	0.17	0.17	0.18	0.18	0.18	0.18
Australia and New Zealand	0.49	0.60	0.60	0.86	0.86	0.96	0.96
Total OECD production	**24.29**	**29.03**	**31.83**	**30.12**	**37.49**	**30.77**	**40.57**
Non-OECD							
Russia	10.50	10.71	10.71	11.22	11.22	12.16	12.16
Other Europe and Eurasia[3]	3.27	3.41	3.41	4.42	4.42	5.18	5.18
China	4.48	5.11	5.11	5.66	5.66	5.84	5.84
Other Asia[4]	3.82	3.85	3.85	3.67	3.67	4.01	4.01
Middle East	1.20	1.03	1.03	0.85	0.85	0.77	0.77
Africa	2.41	2.70	2.70	2.94	2.94	3.33	3.33
Brazil	2.73	3.70	3.70	5.43	5.43	6.12	6.12
Other Central and South America	2.21	2.71	2.71	2.97	2.97	3.47	3.47
Total non-OECD production	**30.63**	**33.21**	**33.21**	**37.17**	**37.17**	**40.88**	**40.88**
Total petroleum and other liquids production	**91.4**	**98.4**	**98.6**	**108.8**	**109.5**	**121.1**	**121.8**
OPEC market share (percent)	39.9	36.7	34.1	38.2	31.8	40.8	33.1

Table D8. International petroleum and other liquids supply, disposition, and prices (continued)
(million barrels per day, unless otherwise noted)

Supply, disposition, and prices	2013	Projections					
		2020		2030		2040	
		Reference	High oil and gas resource	Reference	High oil and gas resource	Reference	High oil and gas resource
Selected world production subtotals:							
Crude oil and equivalents[6]	77.93	82.19	81.78	89.77	88.84	99.09	97.22
Tight oil	3.62	7.49	9.33	9.16	14.57	10.15	17.40
Bitumen[7]	2.11	3.00	3.00	3.95	3.95	4.26	4.26
Refinery processing gain[8]	2.40	2.42	2.59	2.74	2.88	2.97	3.04
Natural gas plant liquids	9.36	11.28	11.89	12.42	13.99	13.79	16.31
Liquids from renewable sources[9]	2.14	2.56	2.57	3.36	3.38	4.22	4.24
Liquids from coal[10]	0.21	0.33	0.33	0.69	0.69	1.05	1.05
Liquids from natural gas[11]	0.24	0.33	0.33	0.51	0.51	0.61	0.61
Liquids from kerogen[12]	0.01	0.01	0.01	0.01	0.14	0.01	0.14
Crude oil production[6]							
OPEC[5]							
Middle East	23.13	21.20	18.63	25.59	18.93	31.79	22.68
North Africa	2.43	2.93	2.93	2.92	2.92	2.96	2.96
West Africa	4.20	4.89	4.89	5.13	5.13	5.29	5.29
South America	2.82	2.86	2.86	2.98	2.98	3.48	3.48
Total OPEC production	**32.60**	**31.89**	**29.32**	**36.62**	**30.10**	**43.52**	**34.54**
Non-OPEC							
OECD							
United States (50 states)	8.90	11.58	13.75	11.01	16.60	10.41	17.51
Canada	3.42	4.35	4.35	5.48	5.48	5.92	5.92
Mexico and Chile	2.59	2.61	2.61	3.00	3.00	3.45	3.45
OECD Europe[2]	2.82	2.17	2.17	1.66	1.66	1.69	1.69
Japan and South Korea	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Australia and New Zealand	0.37	0.47	0.47	0.67	0.67	0.75	0.75
Total OECD production	**18.10**	**21.18**	**23.35**	**21.83**	**27.42**	**22.23**	**29.33**
Non-OECD							
Russia	10.02	10.15	10.15	10.42	10.42	11.10	11.10
Other Europe and Eurasia[3]	3.05	3.18	3.18	4.03	4.03	4.66	4.66
China	4.16	4.54	4.54	4.56	4.56	4.13	4.13
Other Asia[4]	3.04	2.94	2.94	2.45	2.45	2.47	2.47
Middle East	1.16	1.00	1.00	0.82	0.82	0.74	0.74
Africa	1.97	2.18	2.18	2.38	2.38	2.70	2.70
Brazil	2.02	2.87	2.87	4.16	4.16	4.60	4.60
Other Central and South America	1.81	2.25	2.25	2.49	2.49	2.94	2.94
Total non-OECD production	**27.24**	**29.11**	**29.11**	**31.32**	**31.32**	**33.35**	**33.35**
Total crude oil production[6]	**77.9**	**82.2**	**81.8**	**89.8**	**88.8**	**99.1**	**97.2**
OPEC market share (percent)	41.8	38.8	35.8	40.8	33.9	43.9	35.5

[1]Estimated consumption. Includes both OPEC and non-OPEC consumers in the regional breakdown.
[2]OECD Europe = Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.
[3]Other Europe and Eurasia = Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Georgia, Kazakhstan, Kosovo, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Serbia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.
[4]Other Asia = Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), Fiji, French Polynesia, Guam, Hong Kong, India (for production), Indonesia, Kiribati, Laos, Malaysia, Macau, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, and Vietnam.
[5]OPEC = Organization of the Petroleum Exporting Countries = Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[6]Includes crude oil, lease condensate, tight oil (shale oil), extra-heavy oil, and bitumen (oil sands).
[7]Includes diluted and upgraded/synthetic bitumen (syncrude).
[8]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[9]Includes liquids produced from energy crops.
[10]Includes liquids converted from coal via the Fischer-Tropsch coal-to-liquids process.
[11]Includes liquids converted from natural gas via the Fischer-Tropsch natural-gas-to-liquids process.
[12]Includes liquids produced from kerogen (oil shale, not to be confused with tight oil (shale oil)).
OECD = Organization for Economic Cooperation and Development.
Note: Totals may not equal sum of components due to independent rounding. Data for 2013 are model results and may differ from official EIA data reports.
Sources: 2013 Brent and West Texas Intermediate crude oil spot prices: Thomson Reuters. **2013 quantities and projections:** Energy Information Administration (EIA), *AEO2015 National Energy Modeling System runs REF2015.D021915A and HIGHRESOURCE.D021915B; and EIA, Generate World Oil Balance application.*

Appendix E

Comparison of AEO2015 and AEO2014 Reference cases and key updates to models and data

Introduction

This appendix provides a summary comparison of the Reference case for EIA's *Annual Energy Outlook 2015* (AEO2015) with the Reference case for the *Annual Energy Outlook 2014* (AEO2014),[1] which was released in April 2014, including a list of major model and data updates and discussion of key differences in results between the two projections. Table E1 compares projections from the AEO2014 and AEO2015 reports.

Model and data updates

Key model and data updates made for the AEO2015 Reference case include the following:

Macroeconomic

- Incorporated the U.S. Bureau of Economic Analysis (BEA) gross domestic product component revision to 2009 dollars and investment definitional changes.[2] The AEO2015 macroeconomic projections are based on November 2014 IHS Global Insight projections.[3]
- Incorporated a new input-output matrix based on a 2007 benchmark year using 2009 dollars. The input-output matrix now continues to change over time, based on historical relationships developed using previous benchmark matrices to 2013.

Residential, commercial, and industrial

- Incorporated new standards for buildings equipment promulgated during the year, including standards affecting commercial refrigeration equipment, metal halide lamp fixtures, residential furnace fans, external power supplies, and set-top boxes (voluntary agreement).
- Updated cost and performance assumptions for end-use equipment in the buildings sector, based on a report by Navigant Consulting, Inc. and Leidos, reflecting recent and expected technological progress.[4]
- Incorporated more rapid adoption of commercial building codes related to building shell efficiency, based on a Pacific Northwest National Laboratory report.[5]
- Revised and refined market niches used in developing residential distributed generation projections to more accurately reflect solar insolation and marginal prices at the sub-Census division level, based on data from EIA's 2009 Residential Energy Consumption Survey and solar insolation data from the National Renewable Energy Laboratory.[6,7]
- Incorporated 2012 State Energy Data System (SEDS) data for regional benchmarking in the industrial sector.[8]
- Updated and implemented historical natural gas feedstock data in the industrial sector through 2013, based on data from GlobalData.[9]
- Introduced a new Bayesian Dynamic Linear Model (DLM) for ethane and propane price projections in the industrial sector. In the DLM regression, parameters are allowed to vary over time to allow for a dynamic representation of various drivers of ethane and propane prices—such as oil price, natural gas price, hydrocarbon gas liquids (HGL) supply and demand, and bulk chemical shipments. The DLM projects base ethane and propane prices only at Mont Belvieu. To compute sectoral propane prices, historical differences between the base and sectoral prices for propane were applied to the DLM projections for propane. The resulting AEO2015 ethane and propane price projections exhibit a dominant natural gas price influence in the near term and a growing oil price influence in the long term.

[1]U.S. Energy Information Administration, Annual Energy Outlook 2014, DOE/EIA-0383(2014) (Washington, DC, April 2014), www.eia.gov/forecasts/archive/aeo14.

[2]S.H. McCulla, A.E. Holdren, and S. Smith, "Improved Estimates of the National Income and Product Accounts: Results of the 2013 Comprehensive Revision" (U.S. Department of Commerce, Bureau of Economic Analysis, Washington, DC, September 2013), http://www.bea.gov/scb/pdf/2013/09%20September/0913_comprehensive_nipa_revision.pdf.

[3]The AEO2015 Reference case uses IHS Global Insight's November 2014 T301114 workfile. The AEO2015 High Economic Growth case uses the optimistic projection, and the AEO2015 Low Economic Growth case uses the pessimistic projection. In all cases, IHSGI's energy prices and quantities are replaced with EIA's projections.

[4]U.S. Energy Information Administration, EIA—*Technology Forecast Updates—Residential and Commercial Building Technologies—Reference case* (Navigant Consulting, Inc. with Leidos, May 2014).

[5]O.V. Livingston, P.C. Cole, D.B. Elliott, and R. Bartlett, *Building Energy Codes Program: National Benefits Assessment, 1992-2040* (Richland, WA, March 2014), prepared by Pacific Northwest National Laboratory for the U.S. Department of Energy, Building Energy Codes Program, http://www.energycodes.gov/building-energy-codes-program-national-benefits-assessment-1992-2040-0.

[6]U.S. Energy Information Administration, "Residential Energy Consumption Survey (RECS): 2009 RECS Survey Data" (Washington, DC, January 2013), http://www.eia.gov/consumption/residential/data/2009/index.cfm?view=microdata.

[7]National Renewable Energy Laboratory (NREL) "Zip Code Solar Insolation Data Source," http://www.nrel.gov/gis/docs/SolarSummaries.xlsx.

[8]U.S. Energy Information Administration, "State Energy Data System (SEDS)" (Washington, DC, June 27, 2014), http://www.eia.gov/state/seds/seds-data-complete.cfm?sid=US.

[9]GlobalData (New York, NY, 2014) http://www.globaldata.com (subscription site).

Table E1. Comparison of projections in the AEO2015 and AEO2014 Reference cases, 2012-40

			2025		2040	
Energy and economic factors	2012	2013	AEO2015	AEO2014	AEO2015	AEO2014
Primary energy production (quadrillion Btu)						
Crude oil and natural gas plant liquids	17.0	19.2	27.2	23.0	25.4	20.0
Dry natural gas	24.6	25.1	31.3	32.6	36.4	38.4
Coal[a]	20.7	20.0	22.2	22.4	22.6	22.6
Nuclear/uranium	8.1	8.3	8.5	8.2	8.7	8.5
Conventional hydroelectric power	2.6	2.5	2.8	2.8	2.8	2.9
Biomass	4.0	4.2	4.6	5.1	5.0	5.6
Other renewable energy	1.9	2.3	3.4	3.1	4.6	3.9
Other[b]	0.8	1.3	0.9	0.2	1.0	0.2
Total production	**79.6**	**82.7**	**100.9**	**97.4**	**106.6**	**102.1**
Net imports (quadrillion Btu)						
Liquid fuels and other petroleum[c]	16.4	14.0	7.4	11.4	8.6	13.7
Natural gas (- indicates exports)	1.6	1.4	-3.5	-3.4	-5.6	-5.8
Coal, coal coke, and electricity (- indicates exports)	-2.8	-2.6	-2.7	-3.2	-3.5	-3.7
Total net imports	**15.2**	**12.8**	**1.1**	**4.8**	**-0.5**	**4.2**
Energy consumption by fuel (quadrillion Btu)						
Liquid fuels and other petroleum[d]	35.2	35.9	36.9	36.3	36.2	35.4
Natural gas	26.1	26.9	27.6	29.0	30.5	32.3
Coal[a]	17.3	18.0	19.3	19.0	19.0	18.7
Nuclear/uranium	8.1	8.3	8.5	8.2	8.7	8.5
Conventional hydroelectric power	2.6	2.5	2.8	2.8	2.8	2.9
Biomass	2.8	2.9	3.2	3.7	3.5	4.3
Other renewable energy	1.9	2.3	3.4	3.1	4.6	3.9
Other[e]	0.4	0.4	0.3	0.3	0.3	0.3
Total consumption	**94.4**	**97.1**	**102.0**	**102.5**	**105.7**	**106.3**
Energy consumption by sector (quadrillion Btu)[f]						
Residential	19.9	21.1	20.3	20.6	20.9	21.5
Commercial	17.5	18.1	18.9	18.8	20.9	20.9
Industrial	30.8	31.2	36.5	37.4	37.7	38.3
Transportation	26.2	27.0	26.7	25.7	26.6	25.6
Unspecified sector[g]	0.0	-0.3	-0.4	--	-0.4	--
Total consumption	**94.4**	**97.1**	**102.0**	**102.5**	**105.7**	**106.3**
Liquid fuels (million barrels per day)						
Domestic crude oil production	6.5	7.4	10.3	9.0	9.4	7.5
Other domestic production	4.5	5.2	6.5	5.1	6.5	5.2
Net imports	7.4	6.2	2.8	5.1	3.4	6.0
Consumption	18.5	19.0	19.6	19.3	19.3	18.7
Natural gas (trillion cubic feet)						
Dry gas production and supplemental gas	24.1	24.5	30.6	31.9	35.5	37.6
Net imports (- indicates exports)	1.5	1.3	-3.5	-3.4	-5.6	-5.8
Consumption	25.5	26.2	26.9	28.4	29.7	31.6

-- = Not applicable.
See notes at end of table.

Table E1. Comparison of projections in the AEO2015 and AEO2014 Reference cases, 2012-40 (continued)

			2025		2040	
Energy and economic factors	2012	2013	AEO2015	AEO2014	AEO2015	AEO2014
Coal (million short tons)						
Production[a]	1,028	995	1,116	1,128	1,128	1,139
Net exports[h]	118	110	110	135	140	160
Consumption[a]	889	925	1,005	993	988	979
Electricity						
Total capacity, all sectors (gigawatts)	1,063	1,065	1,091	1,110	1,261	1,316
Total net generation, all sectors (billion kilowatthours)	4,055	4,070	4,513	4,622	5,056	5,219
Total electricity use (billion kilowatthours)	3,834	3,836	4,282	4,385	4,797	4,954
Prices (2013 dollars)						
Brent spot crude oil (dollars per barrel)	113	109	91	111	141	144
West Texas Intermediate spot crude oil (dollars per barrel)	96	98	85	109	136	142
Natural gas at Henry Hub (dollars per million Btu)	2.79	3.73	5.46	5.31	7.85	7.77
Domestic coal at minemouth (dollars per short ton)	40.5	37.2	40.3	50.4	49.2	60.0
Average electricity (cents per kilowatthour)	10.0	10.1	11.0	10.3	11.8	11.3
Economic indicators						
Real gross domestic product (trillion 2009 dollars)[i]	15.4	15.7	21.3	--	29.9	--
GDP chain-type price index (2009 = 1.00)[i]	1.05	1.07	1.31	--	1.73	--
Real disposable personal income (trillion 2009 dollars)[i]	11.7	11.7	16.3	--	23.0	--
Value of industrial shipments (trillion 2009 dollars)[i]	6.82	7.00	9.21	--	11.46	--
Population (millions)	315	317	347	347	380	381
Energy-related carbon dioxide emissions (million metric tons)	**5,272**	**5,405**	**5,511**	**5,526**	**5,549**	**5,599**
Primary energy intensity (thousand Btu per 2009 dollar of GDP)	**6.14**	**6.18**	**4.79**	**--**	**3.54**	**--**

[a]Includes waste coal consumed in the industrial and electric power sectors.
[b]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some inputs to refineries.
[c]Includes crude oil, petroleum products, petroleum coke, unfinished oils, alcohols, ethers, blending components, hydrocarbon gas liquids, and non-petroleum-derived fuels such as ethanol and biodiesel.
[d]Includes petroleum-derived fuels and non-petroleum-derived fuels, such as ethanol and biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are hydrocarbon gas liquids and crude oil consumed as a fuel.
[e]Net electricity imports, liquid hydrogen, and non-biogenic municipal waste.
[f]Electric power sector consumption is distributed to the end-use sectors.
[g]Represents consumption unattributed to the sectors above.
[h]Excludes imports to Puerto Rico and the Virgin Islands.
[i]GDP, disposable income, value of shipments, and GDP price index were updated in AEO2015 consistent with the U.S. Bureau of Economic Analysis gross domestic product component revision to 2009 dollars and investment definitional changes. AEO2014 data are 2005-based and are not shown since they are not comparable with 2009-based figures.
Notes: Quantities reported in quadrillion Btu are derived from historical volumes and assumed thermal conversion factors.
-- = Not applicable.

Transportation

- Updated the following by aircraft type and region: sales, stocks, and active and parked aircraft using Jet Inventory Services data;[10] available seat-miles traveled, revenue seat-miles traveled, cargo travel, fuel use, and load factors, using U.S. Department of Transportation, Bureau of Transportation Statistics data;[11] and domestic and international yield[12] using fares and fees published by Airlines for America.[13]
- Updated historical light-duty vehicle and heavy-duty truck vehicle-miles traveled through 2012, using data from U.S. Department of Transportation, Federal Highway Administration,[14] extended through 2014 using the U.S. Department of Transportation, Federal Highway Administration, *Traffic Volume Trends* report.[15]
- Added historical freight rail ton miles through 2013, using Class 1 Railroad data as reported through the U.S. Department of Transportation, Surface Transportation Board.[16]
- Added historical domestic marine ton miles through 2012, based on U.S. Army Corps of Engineers data.[17]
- Revised heavy-duty vehicle, freight rail, and domestic marine travel demand projection methodologies based on a report from IHS Global Insight.[18] The new methodologies will use the Freight Analysis Framework[19] in the historical Census division and commodity ton-mile data, including derivation of ton mile per dollar of industrial output (a key metric used in the travel demand projection methodology). These data include a Geographic Information System modeling estimation of the share of freight truck travel between origin and destination points through intermediate Census divisions.
- Modified the technology adoption and fuel economy calculation for heavy-duty vehicles and added technology availability.
- Modified the domestic and international marine residual fuel oil and distillate fuel shares to match compliance with MARPOL Annex VI,[20] the International Convention for the Prevention of Pollution from Ships, concerned with preventing marine pollution from ships, as assumed in EIA's *Short-Term Energy Outlook*.
- Added an unspecified consumption sector to match the levels of travel and efficiency more consistently with implied fuel use in the transportation sector, and to allow total liquid fuels[21] consumption in AEO2015 to be closer to the totals for each fuel that are reported in EIA's statistical publications as being supplied to markets.

Oil and natural gas production

- Incorporated the impact of world oil prices that remain below $80/bbl (in 2013 dollars) through 2020, versus $98/bbl in AEO2014, to reflect market events through the end of 2014 and the growth of U.S. crude oil production. This change in price expectations limits the degree to which near-term U.S. crude oil and associated dry natural gas production increase, and limits the need for natural gas produced for liquefied natural gas (LNG) exports.
- Revised drilling costs in AEO2015 to directly incorporate assumptions regarding average lateral length and number of laterals per well.
- Updated natural gas plant liquid (NGPL) factors at the play and county levels for tight oil and shale gas formations.
- Updated the estimated ultimate recovery of tight and shale formations at the county level. For the Marcellus Shale, each county was further divided into productive tiers based on geologic dependencies.
- Updated the list of offshore discovered, non-producing fields and the expected resource sizes and startup dates of the fields.

[10] Jet Information Services, Inc., "World Jet Inventory" (Utica, NY, December 2013), http://www.jetinventory.com (subscription site).
[11] U.S. Department of Transportation, Bureau of Transportation Statistics, Form 41, Schedule T-2 (T-100), "Quarterly Traffic and Capacity Data of U.S. Air Carriers, Summarized by Aircraft Type" (Washington, DC, December 2013).
[12] Yield is defined as airline revenue divided by revenue passenger miles traveled.
[13] Airlines for America, "Annual Round Trip Fares and Fees" (Washington, DC, August 2014), http://airlines.org/data/annual-round-trip-fares-and-fees-domestic/ and http://airlines.org/data/annual-round-trip-fares-and-fees-international/.
[14] U.S. Department of Transportation, Federal Highway Administration, "Highway Statistics 2012: Table VM-1, Annual Vehicle Distance Traveled in Miles and Related Data—2012 by Highway Category and Vehicle Type" (Washington, DC, January 2014), http://www.fhwa.dot.gov/policyinformation/statistics/2012/vm1.cfm.
[15] U.S. Department of Transportation, Federal Highway Administration, "June 2014 Traffic Volume Trends" (Washington, DC, June 2014), https://www.fhwa.dot.gov/policyinformation/travel_monitoring/14juntvt/.
[16] U.S. Department of Transportation, Surface Transportation Board, "Annual Report Financial Data" (Washington, DC, 2013), http://www.stb.dot.gov/stb/industry/econ_reports.html.
[17] U.S. Department of Defense, U.S. Army Corps of Engineers, "Waterborne Commerce of the United States, Calendar Year 2012, Part 5—National Summaries, Table 1.4: Total Waterborne Commerce, 1993-2012" (Washington, DC, 2014), http://www.navigationdatacenter.us/wcsc/pdf/wcusnatl12.pdf.
[18] IHS Global, Inc., "NEMS Freight Transportation Module Improvement Study" (June 20, 2014).
[19] U.S. Department of Transportation, Federal Highway Administration, "Freight Analysis Framework," http://www.ops.fhwa.dot.gov/freight/freight_analysis/faf/.
[20] U.S. Environmental Protection Agency, "MARPOL Annex VI" (Washington, DC: January 14, 2015), http://www2.epa.gov/enforcement/marpol-annex-vi.
[21] Liquid fuels (or petroleum and other liquids) include crude oil and products of petroleum refining, natural gas liquids, biofuels, and liquids derived from other hydrocarbon sources (including coal-to-liquids and gas-to-liquids).

- Moved the projection of the composition of NGPL from the Liquid Fuels Market Module (LFMM) to the Oil and Gas Supply Module (OGSM). Added input data in the OGSM for the component (ethane, propane, butane, and pentanes plus) shares of total NGPL at the project level represented in the OGSM. Added capability to account for the volume of ethane that is left in the dry natural gas stream (commonly referred to as *ethane rejection*).

Natural gas transmission and distribution

- Expanded natural gas distribution in AEO2015 to represent a greater number of pipeline routes that allow for bidirectional flows.
- Allowed LNG projects to be added incrementally by a single train rather than by multiple trains and to phase-in over three years rather than two years.
- In circumstances when the Brent price is above (below) a mid-range value, the model can now set world natural gas prices to disconnect from the Brent price at a faster (slower) rate than it would have previously.
- Updated the pricing algorithm for offshore Atlantic and Pacific production.
- Adjusted the representation of Canadian dry natural gas production.
- Increased base-level production to account for a change in Mexico's constitution allowing for increased foreign investment.

Petroleum product and biofuels markets

- Added 40°-50° American Petroleum Institute (API) and 50°+ API crude oil types to reflect increases in tight oil production and potential constraints on refinery processing.
- Included the option to add new condensate splitter units to process 50°+ API crude.
- Modified the LFMM and International Energy Module to permit crude exports to accommodate analysis of the impact of potential relaxation of the current U.S. crude oil export ban.
- Relaxed export restrictions on processed condensate to better match the U.S. Department of Commerce, Bureau of Industry and Security, interpretation of export regulations that allow the export of processed condensate.
- Updated gasoline specifications to reflect Tier 3 gasoline regulations.
- Revised the renewable fuels standard mandate levels for biomass-based diesel to better match expected production capabilities.[22]

Electric power sector

- Revised the assumption for unannounced nuclear retirements in the Reference case downward, from 5.7 gigawatts (GW) in the AEO2014 Reference case to 2 GW in the AEO2015 Reference case. Unannounced nuclear retirements in the AEO2015 Reference case reflect market uncertainty. Announced nuclear retirements are incorporated as reported to the EIA.
- Updated the online start dates for Virgil C. Summer Nuclear Generating Station Units 2 and 3 to 2019 and 2020, respectively, to reflect company announcements.[23]
- Updated expiration dates of firm contractual arrangements for coal-fired power plants that serve California loads.[24] Adjusted the carbon emissions rate for firm imports in accordance with the expiration of contracts.
- Explicitly represented 4.1 GW of coal-fired units that are being converted to natural gas-fired steam units. Added model capability to convert additional coal-fired plants to natural gas-fired plants based on the relative economics, assuming a capital cost for conversion and connection to natural gas pipelines. Once converted, the oil and natural gas steam plants are assumed to have lower operating and maintenance costs than the original coal-fired plant but also a 5% loss in efficiency.
- Updated regional assumptions on transmission and distribution spending as a function of peak load growth, based on historical trends.
- Revised biomass supply model representation of agricultural residues/energy crop feedstocks, by incorporating fully-integrated agricultural model, Policy Analysis System (POLYSYS).

[22]U.S. Energy Information Administration, Monthly Biodiesel Production Report (Washington, DC: July 31, 2014), http://www.eia.gov/biofuels/biodiesel/production/.
[23]SCANA Corporation, "SCANA Corporation Management to Discuss New Nuclear Construction Schedule on August 11, 2014" (Cayce, SC: August 2014), https://www.scana.com/docs/librariesprovider15/pdfs/press-releases/8-11-2014-scana-dicuss-new-nuclear-schedule.pdf?sfvrsn=0.
[24]California Energy Commission, "Actual and Expected Energy from Coal for California" (Sacramento, CA: November 6, 2014), http://www.energy.ca.gov/renewables/tracking_progress/documents/current_expected_energy_from_coal.pdf. Changes in coal contract deliveries are largely related to the California Public Utilities Commission's adopted Greenhouse Gas Emissions Performance Standard (Decision 07-01-039, January 25, 2007, Interim Opinion on Phase 1 Issues: Greenhouse Gas Emissions Performance Standard, http://docs.cpuc.ca.gov/PublishedDocs/PUBLISHED/FINAL_DECISION/64072.htm), which implemented Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006, http://www.energy.ca.gov/emission_standards/documents/sb_1368_bill_20060929_chaptered.pdf).

- Reviewed and updated capital cost assumptions for utility-scale solar PV and wind plants based on assessment of costs reported in trade press and data compiled in Lawrence Berkeley National Laboratory publications *2013 Wind Technologies Market Report*[25] and *Utility-Scale Solar 2013*.[26]
- Added model capability to retrofit existing coal-fired generating units to improve their operating efficiency (heat rate), if economic. An analysis of the heat rate improvement potential of the existing coal fleet sorted existing coal-fired units into quartiles, to reflect varying levels of improvement potential, and developed cost estimates to reflect the investment required to achieve the improvement. The analysis then disaggregated the cost and improvement assumptions based on environmental control configurations, consistent with the coal plant types used in the electricity model. Heat rate improvement retrofits can provide a reduction in fuel use ranging from less than 1% to 10%, depending on the plant type and quartile.

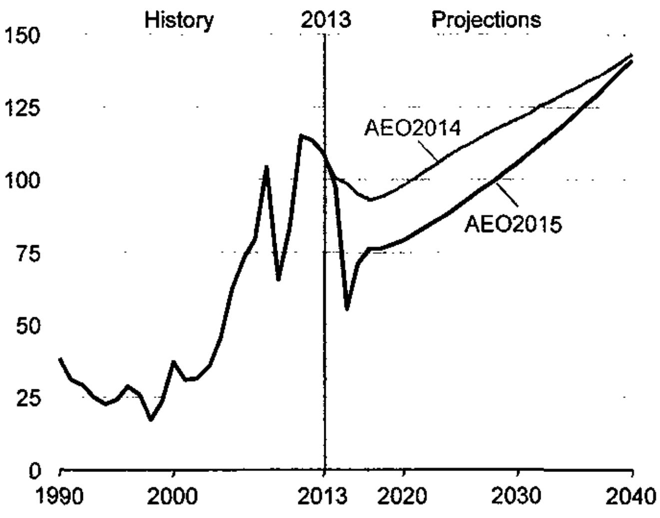
Comparison of AEO2015 and AEO2014 Reference cases

Economic growth

The macroeconomic projections used in AEO2015 are trend projections, with no major shocks anticipated. In long-term projections, the economy's supply capability determines its potential growth. Growth in aggregate supply depends on increases in the labor force, growth of capital stock, and improvements in productivity. Long-term demand growth depends on labor force growth, income growth, and population growth. In the AEO2015 Reference case, U.S. population grows by an average of 0.7%/year from 2013 to 2040, the same rate as in the AEO2014 Reference case over the same period. In the AEO2015 Reference case, real gross domestic product (GDP), labor force, and productivity grow by 2.4%/year, 0.6%/year, and 2.0%/year, respectively, over the same period. Those rates are similar to the annual growth rates for real GDP, labor force, and productivity of 2.5%, 0.6%, and 1.9%, respectively, from 2013 to 2040 in the AEO2014 Reference case.

The annual rate of growth in total industrial production, which includes manufacturing, construction, agriculture, and mining, in the AEO2015 Reference case is lower than the rate in the AEO2014 Reference case, primarily as a result of slower growth in key manufacturing industries, such as food, paper, non-bulk chemicals, and computers. Updated information on how industries supply other industries and meet the demand for different types of GDP expenditures influences the projections for certain industries.[27] For example, as a result of restructuring in the pulp and paper industry, trade in consumer goods and industrial supplies has a greater impact on the industry's production in AEO2015 than it did in previous AEOs. The annual rate of growth in total industrial production from 2013 to 2040 is 1.8% in AEO2015, compared with 2.1% in AEO2014. The manufacturing share of total gross output in 2040 is 17% in the AEO2015 Reference case, compared with 18% in AEO2014, mostly because of more-rapid growth in service and nonmanufacturing industries, such as wholesale trade, transportation, and warehousing.

Figure E1. Average annual Brent crude oil spot prices in the AEO2015 and AEO2014 Reference cases, 1990-2040 (2013 dollars per barrel)



Energy prices

Crude oil

In the AEO2015 Reference case, the Brent spot price for crude oil (in 2013 dollars) falls from $109/barrel (bbl) in 2013 to $56/bbl in 2015 and then increases to $76/bbl in 2018. After 2018, the Brent price increases, reaching $141/bbl in 2040 ($229/bbl in nominal dollars), as growing demand leads to the development of more costly resources (Figure E1). In the AEO2014 Reference case, the projected Brent price in 2040 was $144/bbl (2013 dollars).

Among the key assumptions that affect crude oil use in the AEO2015 Reference case are average economic growth of 1.9%/year for major U.S. trading partners;[28] average economic growth for other U.S. trading partners of 3.8%/year; and declining U.S. consumption of liquid fuels per unit of GDP. As a result, there is a slight decrease in liquids consumption by the Organization for Economic Cooperation and Development (OECD) countries.

[25] R. Wiser and M. Bolinger, 2013 Wind Technologies Market Report, DOE/GO-102014-4459 (Washington, DC: August 2014), http://emp.lbl.gov/sites/all/files/2013_Wind_Technologies_Market_Report_Final3.pdf.
[26] M. Bolinger and S. Weaver, Utility-Scale Solar 2013 (Washington, DC: September 2014), http://emp.lbl.gov/sites/all/files/LBNL_Utility-Scale_Solar_2013_report.pdf.
[27] The industrial output model of the NEMS Macroeconomic Activity Module now uses the Bureau of Economic Analysis (BEA) detailed input-output matrices for 2007 rather than for 2002 (http://bea.gov/industry/io_annual.htm) and now incorporates information from the aggregate input-output matrices (http://bea.gov/industry/gdpbyind_data.htm).
[28] Major trading partners include Australia, Canada, Switzerland, United Kingdom, Japan, Sweden, and the Eurozone.

The non-OECD consumption level of 75 million barrels per day (bbl/d) in 2040 in the AEO2015 Reference case is about 7% higher than the 2040 level in the AEO2014 Reference case, and the difference more than offsets the impact of lower consumption in the OECD countries. The result is an increase in total world consumption to 121 million bbl/d in 2040 in AEO2015, which is 3% higher than in AEO2014. Non-OPEC (particularly U.S.) liquids production in AEO2015 increases to levels above those in AEO2014, and the OPEC market share in the AEO2015 Reference case rises only slightly, from 40% in 2013 to 41% in 2040, as compared with a 44% market share in 2040 in AEO2014.

Liquid products

The real U.S. price of end-use motor gasoline (2013 dollars) in the AEO2015 Reference case falls from $3.53/gallon in 2013 to a low point of $2.31/gallon in 2015, before rising to $3.90/gallon in 2040, in response to decreasing—and then increasing—crude oil prices. The motor gasoline price in 2040 is 2% lower than the $3.96/gallon price in the AEO2014 Reference case, because of lower crude oil prices. The end-use price of diesel fuel to the transportation sector in the AEO2015 Reference case follows a similar pattern, dropping from $3.86/gallon in 2013 to $2.70/gallon in 2015 and then rising to $4.75/gallon in 2040 (compared with $4.80/gallon in 2040 in the AEO2014 Reference case).

Natural gas

On average, the Henry Hub spot price for natural gas in the AEO2015 Reference case is only 2% (or $0.13/million Btu in 2013 dollars) lower than in the AEO2014 Reference case from 2013 to 2040. The Henry Hub natural gas spot prices in AEO2015 are slightly lower than the AEO2014 spot prices in each year, with the exception of the period from 2020 to 2027 and in 2040. These price levels are consistent with 3% lower cumulative U.S. dry natural gas production through 2040 in the AEO2015 Reference case relative to the AEO2014 Reference case.

Although the average production, consumption, and price levels are similar in the AEO2015 and AEO2014 Reference cases, there are some notable differences in the components. For instance, while natural gas consumption by natural gas vehicles and electricity generators in AEO2015 is lower than in AEO2014, residential and commercial consumption are generally higher. On the supply side, higher dry natural gas production in the AEO2015 Reference case in the East region (which includes the Marcellus and Utica formations) compared with the AEO2014 Reference case is more than offset by lower production levels in the Gulf Coast and Midcontinent regions. The relative location and composition of supply and demand affect regional pricing and national averages. For this and other reasons, average delivered natural gas prices to residential and commercial customers from 2013 to 2040 are 4% lower in the AEO2015 Reference case than in the AEO2014 Reference case.

Coal

The average minemouth price of coal increases by 1.0%/year, from $1.84/million Btu in 2013 to $2.44/million Btu in 2040 (2013 dollars) in the AEO2015 Reference case. In comparison, the price in the AEO2014 Reference case increases by 1.5%/year, from $2.02/million Btu in 2013 to $3.00/million Btu in 2040. The average minemouth price of coal is about 19% lower, on average, across the projection timeframe in AEO2015 when compared with AEO2014, reflecting lower volumes and prices for high-priced coking coal exports, the shutdown of some high-cost mining operations, and a less pessimistic outlook for productivity. Similarly, with a few exceptions, the regional minemouth prices of coal in AEO2015 are lower than those in AEO2014.

The slower rate of increase in the minemouth price of coal in the AEO2015 Reference case reflects recent year-over-year improvements in labor productivity in 9 of the 14 coal supply regions, many of which have not seen productivity gains since 2000, and a slowing of productivity declines in 4 of the other regions. However, both the AEO2015 and AEO2014 Reference cases assume that cost savings from improvements in coal mining technology will continue to be outweighed by increases in production costs associated with moving into reserves that are more costly to mine. Thus, both projections show the average minemouth price of coal rising steadily after 2015.

Electricity

In the AEO2015 Reference case, end-use electricity prices are higher than in the AEO2014 Reference case throughout most of the projection. The higher price outlook reflects market dynamics, as well as revised assumptions for transmission and distribution costs in AEO2015.

The end-use price of electricity is defined by generation, transmission, and distribution cost components. Natural gas prices are a significant determinant of generation costs. In the AEO2015 Reference case, delivered natural gas prices to electricity generators are lower than in the AEO2014 Reference case in the first few years of the projection but higher throughout most of the 2020s. From 2020 to 2030, the generation cost component of end-use electricity prices is, on average, 4% higher in AEO2015 than in AEO2014.

The AEO2015 Reference case includes higher transmission and distribution cost components relative to the AEO2014 Reference case, reflecting an updated representation of trends in transmission and distribution costs. In 2040, the transmission cost component in the AEO2015 Reference case is 14% higher than it was in the AEO2014 Reference case—1.29 cents/kilowatthour (kWh), compared with 1.13 cents/kWh—while the distribution cost component is 15% higher (3.01 cents/kWh compared with 2.61 cents/kWh). The faster growth in the transmission and distribution cost components of end-use electricity prices in

AEO2015 reflects recent historical trends and an expectation that transmission and distribution costs will continue to increase as new transmission and distribution facilities and *smart grid* components (e.g., advanced meters, sensors, controls, etc.) are added, existing infrastructure is upgraded to enhance the reliability and resiliency of the grid, and new resources connect to the grid.

Average end-use electricity price in 2030 is 11.1 cents/kWh (2013 dollars) in the AEO2015 Reference case, compared to 10.6 cents/kWh in the AEO2014 Reference case. Prices continue rising to 11.8 cents/kWh in 2040 in the AEO2015 Reference case, compared to 11.3 cents/kWh in 2040 in the AEO2014 Reference case.

Energy consumption by sector

Transportation

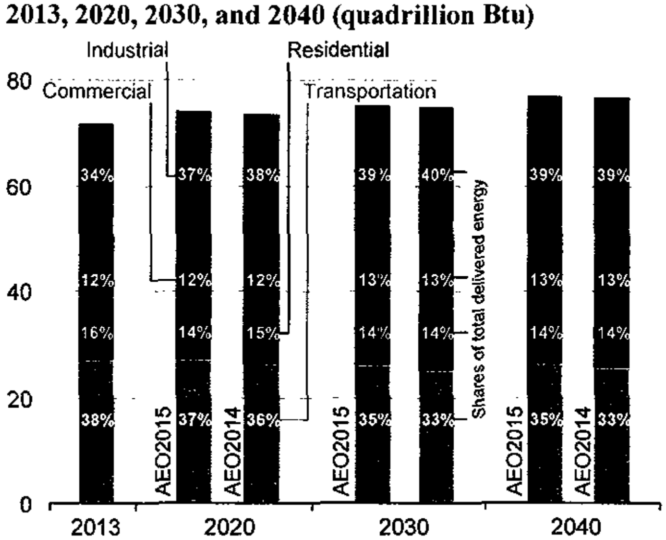
Delivered energy consumption in the transportation sector in the AEO2015 Reference case is higher than in AEO2014 (26.5 quadrillion Btu in 2040 compared with 25.5 quadrillion Btu), with energy consumption for nearly all transportation modes higher in AEO2015 throughout most of the projection, because of higher macroeconomic indicators and lower fuel prices (Figure E2).

Light-duty vehicle (LDV) energy consumption declines in the AEO2015 Reference case from 15.7 quadrillion Btu in 2013 to 12.6 quadrillion Btu in 2040, compared with 12.1 quadrillion Btu in 2040 in AEO2014. Greenhouse gas emission standards and corporate average fuel economy (CAFE) standards increase new LDV fuel economy through model year 2025 and beyond in the AEO2015 Reference case, with new, more fuel-efficient vehicles gradually replacing older vehicles on the road. The increase in fuel economy raises the LDV vehicle stock average miles per gallon by 2.0%/year, from 21.9 in 2013 to 37.0 in 2040. The increase in LDV fuel economy more than offsets modest growth in vehicle-miles traveled (VMT), which averages 1.1%/year from 2013 to 2040 as a result of changes in driving behavior related to demographics. Stock fuel economy is lower, and LDV VMT is higher, in the AEO2015 Reference case than in AEO2014.

LDVs powered exclusively by motor gasoline remain the predominant vehicle type in the AEO2015 Reference case, retaining a 78% share of new vehicle sales in 2040, down only somewhat from 83% in 2013. The fuel economy of LDVs fueled by motor gasoline continues to increase, and advanced technologies for fuel efficiency subsystems are added, such as micro hybridization, which is installed in 42% of new motor gasoline LDVs in 2040. Sales of new LDVs powered by fuels other than gasoline (such as diesel, electricity, or E85) and LDVs using hybrid drivetrains (such as plug-in hybrid or gasoline hybrid-electric vehicles) increase modestly in the AEO2015 Reference case, from 17% of new sales in 2013 to 22% in 2040. Ethanol-flex-fuel vehicles account for 10% of new LDV sales in 2040 followed by hybrid electric vehicles at 5%, up from 3% in 2013, diesel vehicles at 4% in 2040, up from 2% in 2013, and plug-in hybrid vehicles and electric vehicles at about 1% each, both up from negligible shares in 2013. In AEO2015, new vehicle sales shares in 2015 are generally similar to those in AEO2014. In AEO2014, the motor gasoline share of new LDVs sales was 78% in 2040 (with 42% including micro hybridization), followed by 11% ethanol-flex-fuel, 5% hybrid electric, 4% diesel, and 1% each for plug-in hybrid and electric vehicles.

In the AEO2015 Reference case, delivered energy use by heavy-duty vehicles (HDVs) increases from 5.8 quadrillion Btu in 2013 to 7.3 quadrillion Btu in 2040 (compared with 7.5 quadrillion Btu in 2040 in AEO2014). Industrial output growth in AEO2015 leads to solid growth in HDV VMT, averaging 1.5%/year from 2013 to 2040. Competitive natural gas prices significantly increase demand for LNG and compressed natural gas in AEO2015, from an insignificant share in 2013 to 7% of total HDV energy consumption in 2040 (which is less than the 9% share in AEO2014, as a result of differences in fuel price projections).

Figure E2. Delivered energy consumption by end-use sector in the AEO2015 and AEO2014 Reference cases, 2013, 2020, 2030, and 2040 (quadrillion Btu)



Industrial

Total industrial delivered energy consumption grows by 22% in the AEO2015 Reference case, to about 30 quadrillion Btu in 2040, which is about 0.4 quadrillion Btu lower than the 2040 projection in the AEO2014 Reference case. The lower level of total industrial energy consumption in AEO2015 results from lower annual growth in the total value of industrial shipments (1.8%/year) compared with AEO2014 (2.1%/year).

Although total energy consumption levels are similar in the AEO2015 and AEO2014 Reference cases, there are some notable changes in consumption of individual fuels. In AEO2015, the liquid feedstock slate for the bulk chemical industry includes relatively more HGL (ethane and liquefied petroleum gases (LPG)) and less heavy feedstock (naphtha and gasoil) compared with AEO2014. The higher level of HGL feedstock use results from relatively low ethane and LPG prices relative to the prices of oil-based naphtha/gasoil feedstock, as a result of more HGL supply in the AEO2015

Reference case than in AEO2014 and the implementation of a new ethane pricing model that links ethane prices more closely with natural gas prices.

Another notable change from AEO2014 in the AEO2015 Reference case is that total consumption of renewable fuels is more than 0.5 quadrillion Btu lower in AEO2015 as a result of lower shipments from the paper and pulp industry. Industrial electricity consumption is also lower in AEO2015, in part as a result of lower shipments of metal-based durables, especially computers. Through 2022, natural gas consumption is higher in the AEO2015 Reference case than in AEO2014, as a result of higher lease and plant fuel use and an increase in feedstock use, reflecting more optimistic assumptions for ammonia and methanol plant operations based on recent trends. However, after 2022 natural gas consumption is lower in the AEO2015 Reference case, because of lower lease and plant fuel use stemming from lower dry natural gas production, and because of lower shipments in the natural gas-intensive paper and pulp industry.

Residential

Residential delivered energy consumption decreases slightly in the AEO2015 Reference case from 2013 to 2040, with growth in electricity consumption offset by declining use of fossil fuels. Consumption levels are lower than those in the AEO2014 Reference case for most fuels, although natural gas use is slightly higher because of lower projected prices. Delivered electricity consumption is 5.4 quadrillion Btu and natural gas consumption is 4.3 quadrillion Btu in 2040 in AEO2015, compared with 5.7 quadrillion Btu and 4.2 quadrillion Btu, respectively, in AEO2014. The lower consumption levels in AEO2015 are explained in part by slower near-term growth in the number of households.

Commercial

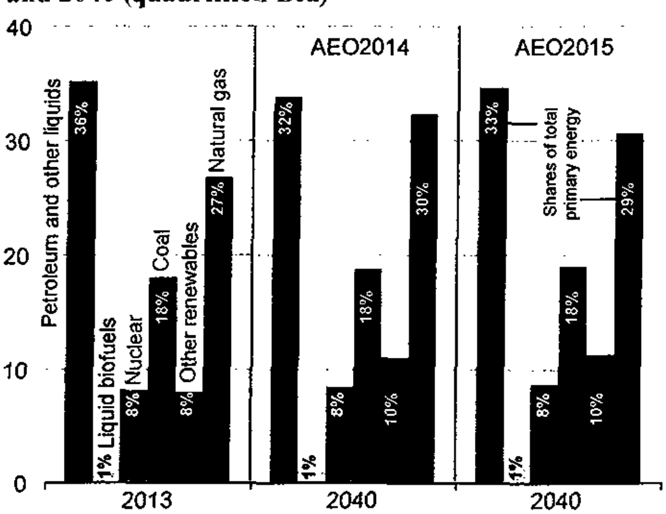
Commercial sector delivered energy consumption grows from 8.7 quadrillion Btu in 2013 to 10.1 quadrillion Btu in 2040 in the AEO2015 Reference case, similar to the AEO2014 Reference case, despite higher consumption in the near term. Commercial electricity consumption increases by 0.8%/year from 2013 to 2040 in AEO2015, lower than the 1.0% average annual growth in commercial floorspace, in part, because of lower demand for lighting and refrigeration than projected in AEO2014.

Energy consumption by primary fuel

Total primary energy consumption grows by 8.8% in the AEO2015 Reference case, from 97.1 quadrillion Btu in 2013 to 105.7 quadrillion Btu in 2040—600 trillion Btu less than in AEO2014, where total primary energy consumption grew by 10.2% to 106.3 quadrillion Btu in 2040 (Figure E3).

Total liquid fuels consumption increases slightly (300 trillion Btu) in the AEO2015 Reference case (the AEO2014 Reference case showed a decline of 600 trillion Btu), as declining consumption of motor gasoline offsets most of the growth in other liquids uses from 2013 to 2040. However, total liquid fuel consumption is 0.9 quadrillion Btu higher in 2040 in the AEO2015 Reference case than in the AEO2014 Reference case. Jet fuel, motor gasoline, and industrial propane use are each about 500 trillion Btu higher in 2040 in AEO2015 than in AEO2014, as a result of updates and revisions made in the air transportation model and lower petroleum fuel prices, as well as upward revisions in output projections for the chemical industry. Liquids consumption in the transportation sector also increases in AEO2015 as the result of the addition of an *unspecified* consumption sector, which was added to improve the consistency of matching travel and efficiency levels with implied fuel use in the transportation sector, so that total consumption of liquid fuels in AEO2015 agrees more closely with the combined total for all fuels reported as being supplied to markets in EIA statistical publications.

Figure E3. Primary energy consumption by fuel in the AEO2015 and AEO2014 Reference cases, 2013 and 2040 (quadrillion Btu)



In the AEO2015 Reference case, domestic natural gas consumption increases from 26.2 trillion cubic feet (Tcf) in 2013 to 29.7 Tcf in 2040, 1.9 Tcf lower than in the AEO2014 Reference case. The lower level of total natural gas consumption results from a 1.9 Tcf lower level of natural gas use in the electric power sector in 2040 in AEO2015. Natural gas consumption in the residential and commercial sectors is up slightly.

In the electric power sector, natural gas faces increased competition from nuclear power and renewables, particularly wind. Also, demand for electricity in the buildings sector in 2040 is about 0.3 quadrillion Btu lower than in AEO2014, as a result of increases in building efficiency standards and updates to lighting parameters in AEO2015. Electricity demand is also lower in some industrial sectors where output does not increase as rapidly in AEO2015 as was projected in AEO2014.

Total coal consumption in the AEO2015 Reference case is 19.0 quadrillion Btu (988 million short tons) in 2040—similar to the AEO2014 Reference case projection of 18.7 quadrillion Btu (979 million short tons) in 2040.

Total consumption of marketed renewable fuels grows by 1.3%/year in the AEO2015 Reference case, the same rate of growth as in the AEO2014 Reference case. However, the mix of renewable fuels is different in AEO2015, with more use of wind in the electric power sector, and less use of biomass in the industrial sector as a result of lower overall shipments in the paper industry. AEO2015 includes 3.0 quadrillion Btu of wind energy consumption in the electric power sector in 2040, compared with 2.4 quadrillion Btu in AEO2014, and the paper industry uses 1.2 quadrillion Btu of wood and pulping liquor in 2040 compared with 1.9 quadrillion Btu in 2040 in the AEO2014 Reference case.

Energy production and imports

In the AEO2015 Reference case, U.S. imports and exports of energy come into balance around 2028 as net energy imports decline both in absolute terms and as a share of total U.S. energy consumption (Figure E4). The United States is a net energy exporter in selected years—for example, from 2029 through 2032, and from 2037 through 2040. Over the projection period, the United States shifts from being a net importer of about 12.8 quadrillion Btu of energy in 2013 (about 13% of total U.S. energy demand) to a net exporter of about 0.5 quadrillion Btu in 2040. In the AEO2014 Reference case, the United States remained a net importer of energy, with net imports of about 4.2 quadrillion Btu in 2040.

Liquids

U.S. crude oil production in the AEO2015 Reference case increases from 7.4 million bbl/d in 2013 to 9.4 million bbl/d in 2040—26% higher than in the AEO2014 Reference case, despite lower prices. Production in AEO2015 reaches 10.6 million bbl/d in 2020, compared with a high of 9.6 million bbl/d in 2019 in AEO2014. Higher production volumes result mainly from increased onshore oil production, predominantly from tight (very low permeability) formations. Lower 48 onshore tight oil production reaches 5.6 million bbl/d in 2020 in the AEO2015 Reference case before declining to 4.3 million bbl/d in 2040, 34% higher than in AEO2014. The pace of oil-directed drilling in the near term is faster in AEO2015 than in AEO2014, as producers continue to locate and target the *sweet spots* of plays currently under development.

Lower 48 offshore crude oil supply grows from 1.4 million bbl/d in 2013 to 2.2 million bbl/d in 2019 in the AEO2015 Reference case, before fluctuating in accordance with the development of projects in the deepwater and ultra-deepwater portions of the Gulf of Mexico. In 2040, Lower 48 offshore production totals 2.2 million bbl/d in AEO2015, 9% more than in the AEO2014 Reference case.

U.S. net imports of liquid fuels as a share of total domestic consumption continue to decline in the AEO2015 Reference case, primarily as a result of increased domestic oil production. Net imports of liquid fuels as a share of total U.S. liquid fuel use reached 60% in 2005 before dipping below 50% in 2010 and falling to an estimated 33% in 2013 (Figure E5). The net import share of domestic liquid fuels consumption declines to 14% in 2020 in the AEO2015 Reference case—compared with 26% in the AEO2014 Reference case—as a result of faster growth of domestic liquid fuels supply[29] compared with growth in consumption. Domestic liquid fuels supply begins to decline after 2023 in the AEO2015 Reference case, and as a result, the net import share of domestic liquid fuels consumption rises from 14% in 2022 to 17% in 2040. However, domestic liquid fuels supply in the AEO2015 Reference case is 25% higher in 2040 than in the AEO2014 Reference case, while domestic consumption is only 3% higher. As a result, despite increasing after 2020, the percentage of U.S. liquid fuel supply from net imports in the AEO2015 Reference case remains just over half that in the AEO2014 Reference case through 2040.

Figure E4. Total energy production and consumption in the AEO2015 and AEO2014 Reference cases, 1980-2040 (quadrillion Btu)

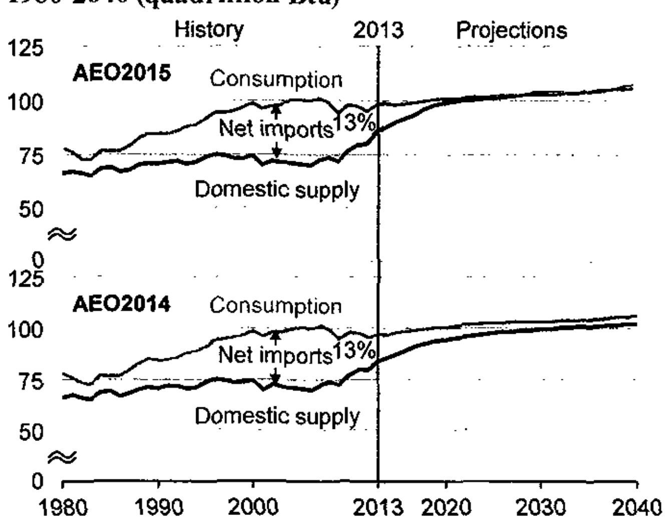
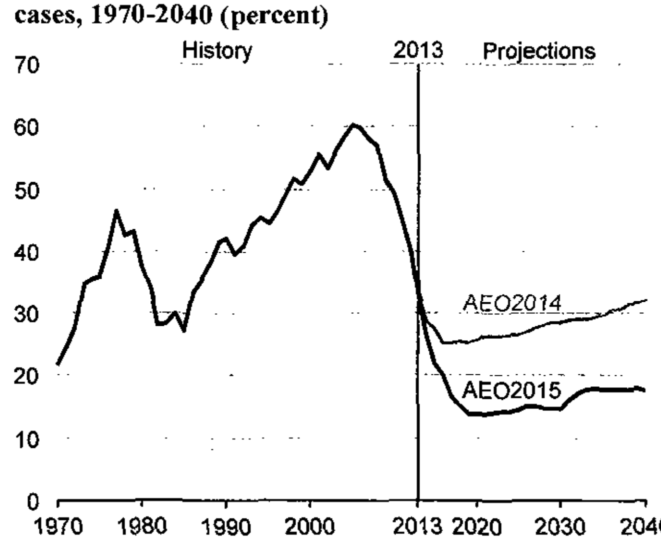


Figure E5. Share of U.S. liquid fuels supply from net imports in the AEO2015 and AEO2014 Reference cases, 1970-2040 (percent)



[29]Total domestic liquid fuels minus net imports, plus domestic HGL production.

Natural gas

In the AEO2015 Reference case, U.S. production of dry natural gas after 2019 is lower than in the AEO2014 Reference case projection, and in 2040 it is lower by more than 2 trillion cubic feet (Tcf). Lower production levels are a result of lower natural gas prices and a decrease in demand for natural gas by electricity generators because of fewer nuclear plant retirements and more renewable generation capacity in AEO2015. However, dry natural gas production from shale gas and tight oil plays is generally higher in AEO2015, offsetting some of the decreases in other areas. Increases in shale gas production are made possible by the dual application of horizontal drilling and hydraulic fracturing. Another contributing factor is ongoing drilling in shale plays and other resources with high concentrations of natural gas liquids and crude oil, which, in energy-equivalent terms, have a higher value than dry natural gas, even with lower crude oil prices.

In the AEO2015 Reference case, the United States becomes an overall net exporter of natural gas in 2017, one year earlier than in AEO2014, and a net pipeline exporter of natural gas in 2018, three years earlier than in AEO2014. In the AEO2015 Reference case, imports from Canada, which largely enter the western United States, and exports into Canada, which generally exit out of the East, are generally lower than in the AEO2014 Reference case. Imports from Canada remain lower in the AEO2015 Reference case than in the AEO2014 Reference case through 2040, while exports to Canada are higher in the AEO2015 Reference case from 2021 to 2028, before decreasing below AEO2014 levels through 2040. Net pipeline imports from Canada fall steadily until 2030 in AEO2015, then increase modestly through 2040, when growth in shale production stabilizes in the United States but continues to increase in Canada.

Net pipeline exports to Mexico increase almost twofold in the AEO2015 Reference case from 2017 to 2040, with additional pipeline infrastructure added to enable the Mexican market to receive more natural gas via pipeline from the United States. However, pipeline exports to Mexico in the later years of the AEO2015 Reference case are lower than projected in the AEO2014 Reference case, because Mexico is assumed to increase domestic production as a result of constitutional reforms that permit more foreign investment in its oil and natural gas industry.

Beginning in 2024, exports of liquefied natural gas (LNG) are slightly lower in the AEO2015 Reference case than in AEO2014, driven by lower crude oil prices. However, the impact of crude oil prices on the projection is dampened by changes in assumptions about how rapidly new LNG export terminals will be built.

Coal

Total U.S. coal production in the AEO2015 Reference case grows at an average rate of 0.5%/year, from 985 million short tons (19.9 quadrillion Btu) in 2013 to 1,117 million short tons (22.5 quadrillion Btu) in 2040. In comparison, U.S. production in the AEO2014 Reference case was projected to increase by 0.3%/year, from 1,022 million short tons (20.7 quadrillion Btu) in 2013 to 1,121 million short tons (22.4 quadrillion Btu) in 2040. Actual coal production in 2013 was 4% lower than projected in AEO2014, as a result of a large drawdown of coal inventories at coal-fired power plants.

From 2013 through 2020, coal production in the AEO2015 Reference case is lower than projected in the AEO2014 Reference case, as lower natural gas prices result in the substitution of natural gas for coal in power generation. After 2020, total coal production in the AEO2014 and AEO2015 projections are nearly identical, with both hovering around 1.1 billion short tons through 2040, because of similar patterns of capacity additions and retirements at coal-fired power plants and similar coal-fired capacity utilization rates in the two projections. The outlook for U.S. coal exports is lower in AEO2015 than in AEO2014 throughout the projection period. Between 2013 and 2015, U.S. coal exports decline sharply in the AEO2015 Reference case as a result of strong international competition and lower international coal prices; but from 2015 through 2040 they increase gradually. Compared with AEO2014, coal exports in AEO2015 are 27% lower in 2015 and 13% lower in 2040.

Overall, regional patterns of U.S. coal production are similar in the AEO2015 and AEO2014 Reference cases. Production in the Eastern Interior region increases in both projections by about 100 million short tons from 2013 to 2040. The AEO2015 outlook for Central Appalachian coal production is similar to the AEO2014, but is about 7 million short tons (7%) higher, on average, than the AEO2014 from 2015 through 2040. Northern Appalachian coal production in 2040 is 20 million short tons lower in AEO2015 than projected in the AEO2014 Reference case. Production from Wyoming's Powder River Basin, currently the lead coal-producing region in the United States, is lower from 2013 through 2018 in AEO2015 than projected in AEO2014, but then increases at a more rapid pace through 2026 before declining slightly and eventually moving to levels consistent with the AEO2014 projection from 2032 through 2040.

Electricity generation

Total electricity consumption in the AEO2015 Reference case, including both purchases from electric power producers and on-site generation, grows from 3,836 billion kWh in 2013 to 4,797 billion kWh in 2040. The average annual increase of 0.8% from 2013 to 2040 is slightly below the 1.0% annual rate in the AEO2014 Reference case. In all the end-use sectors, electricity demand growth is slower than projected in AEO2014, with the largest difference in growth in the residential sector.

Coal has traditionally been the largest energy source for electricity generation. However, the combination of slow growth in electricity demand, competitively priced natural gas, programs encouraging renewable fuel use, and the implementation of environmental rules dampens future coal use in both the AEO2015 and AEO2014 Reference cases. Beginning in 2019, coal-fired electricity generation is between 2% and 4% percent higher in the AEO2015 Reference case than in AEO2014 through 2025, as a result of higher natural gas prices. After 2025, coal-fired generation remains between one and two percent higher in AEO2015 than in AEO2014 (Figure E6). The AEO2015 Reference case does not include the proposed Clean Power Plan[30] for existing fossil-fuel-fired electric generating units, which, if implemented, could substantially change the generation mix.

Coal accounted for 39% of total generation in 2013, and its share falls to 34% in 2040 in the AEO2015 Reference case. The coal share of total generation was lower at 32% in 2040 in the AEO2014 Reference case. With retirements of coal-fired generating capacity far outpacing new additions, total coal-fired generating capacity falls in the AEO2015 Reference case from 304 GW in 2013 to 260 GW in 2040, which is similar to the 2040 capacity projection in the AEO2014 Reference case.

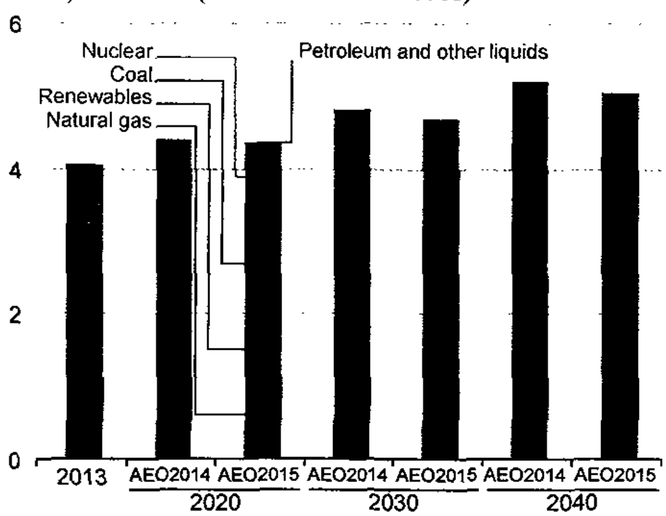
Electricity generation from natural gas grows at a slower rate in the AEO2015 Reference case than in the AEO2014 Reference case because of lower growth in overall electricity demand, higher natural gas prices in the midterm, fewer nuclear retirements, and more renewable capacity additions leading to less need for new natural gas-fired capacity. In the AEO2015 Reference case, natural gas-fired generation in 2040 is 15% lower than projected in the AEO2014 Reference case. Natural gas capacity additions still make up most (58%) of total capacity additions from 2014 to 2040 but represent a smaller share of new builds than the 74% of total additions projected in AEO2014. As a share of total generation, natural gas does not surpass the coal-fired generation share in the AEO2015 Reference case over the projection period as it did in the AEO2014 Reference case.

Increased generation from renewable energy accounts for 38% of the overall growth in electricity generation from 2013 to 2040 in the AEO2015 Reference case. Generation from renewable resources grows in the near term as new capacity under construction comes online in response to federal tax credits, state-level policies, and declining capital costs for wind and solar projects. In the final decade of the projection, renewable generation growth is almost exclusively the result of the increasing cost-competitiveness of renewable generation with other, nonrenewable technologies.

Renewable generation is higher throughout most of the projection period in AEO2015 than was projected in AEO2014, and it is about 7% higher in 2040. Combined generation from solar and wind power in AEO2015 is about 28% higher in 2040 than projected in AEO2014, as a result of more planned renewable capacity additions and recent declines in the construction costs for new wind plants. Renewable generation accounts for 18% of total generation in 2040 in the AEO2015 Reference case, compared with 16% in AEO2014.

In the AEO2015 Reference case, electricity generation from nuclear power plants increases by 6%, from 789 billion kWh in 2013 to 833 billion kWh in 2040, and accounts for about 16% of total generation in 2040, slightly above the share in AEO2014. Over the projection period, nuclear generation in AEO2015 is on average 3% higher than projected in AEO2014, with about 4 GW less nuclear capacity retired from 2013 to 2020 in the AEO2015 Reference case, compared to the AEO2014 Reference case.

Figure E6. Electricity generation by fuel in the AEO2015 and AEO2014 Reference cases, 2013, 2020, 2030, and 2040 (trillion kilowatthours)



Energy-related CO_2 emissions

Total U.S. energy-related CO_2 emissions remain well below their 2005 level of 5,993 million metric tons (mt) through the end of the projection period in the AEO2015 Reference case.[31] Energy-related CO_2 emissions in 2040 are 5,549 million mt, or 50 million mt (0.9%) below the AEO2014 Reference case projection. This decrease may appear counterintuitive, since coal consumption is 1.4% higher, petroleum and other liquids consumption is 2.4% higher, and total renewable energy consumption is lower, all putting upward pressure on emissions. However, natural gas consumption is 5.6% lower, and while it has a lower carbon factor than the other fossil fuels, it does emit CO_2. Nuclear energy consumption in 2040 is 2.8% higher in AEO2015 than in AEO2014, and total energy demand is 0.5% lower. The net result is somewhat lower energy-related CO_2 emissions in the AEO2015 Reference case than in the AEO2014 Reference case.

[30] U.S. Environmental Protection Agency, "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units," *Federal Register*, pp. 34829-34958 (Washington, DC: June 18, 2014) https://www.federalregister.gov/articles/2014/06/18/2014-13726/carbon-pollution-emission-guidelines-for-existing-stationary-sources-electric-utility-generating.

[31] The year 2005 is the base year for the Obama Administration's goal for emission reductions of 17% by 2020. In the AEO2015 Reference case, energy-related CO_2 emissions in 2020 are 8% below the 2005 level.

Figure and table sources

Links current as of April 2015

Table E1. Comparison of projections in the AEO2015 and AEO2014 Reference cases, 2012-40: AEO2015 National Energy Modeling System, run REF2015.D021915A; and AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure E1. Average annual Brent crude oil spot prices in the AEO2015 and AEO2014 Reference cases, 1990-2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A; and AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure E2. Delivered energy consumption by end-use sector in the AEO2015 and AEO2014 Reference cases, 2013, 2020, 2030, and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A; and AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure E3. Primary energy consumption by fuel in the AEO2015 and AEO2014 Reference cases, 2013 and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A; and AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure E4. Total energy production and consumption in the AEO2015 and AEO2014 Reference cases, 1980-2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A; and AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure E5. Share of U.S. liquid fuels supply from net imports in the AEO2015 and AEO2014 Reference cases, 1970-2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A; and AEO2014 National Energy Modeling System, run REF2014.D102413A.

Figure E6. Electricity generation by fuel in the AEO2015 and AEO2014 Reference cases, 2013, 2020, 2030, and 2040: History: U.S. Energy Information Administration, *Monthly Energy Review*, November 2014, DOE/EIA-0035(2014/11). **Projections:** AEO2015 National Energy Modeling System, run REF2015.D021915A; and AEO2014 National Energy Modeling System, run REF2014.D102413A.

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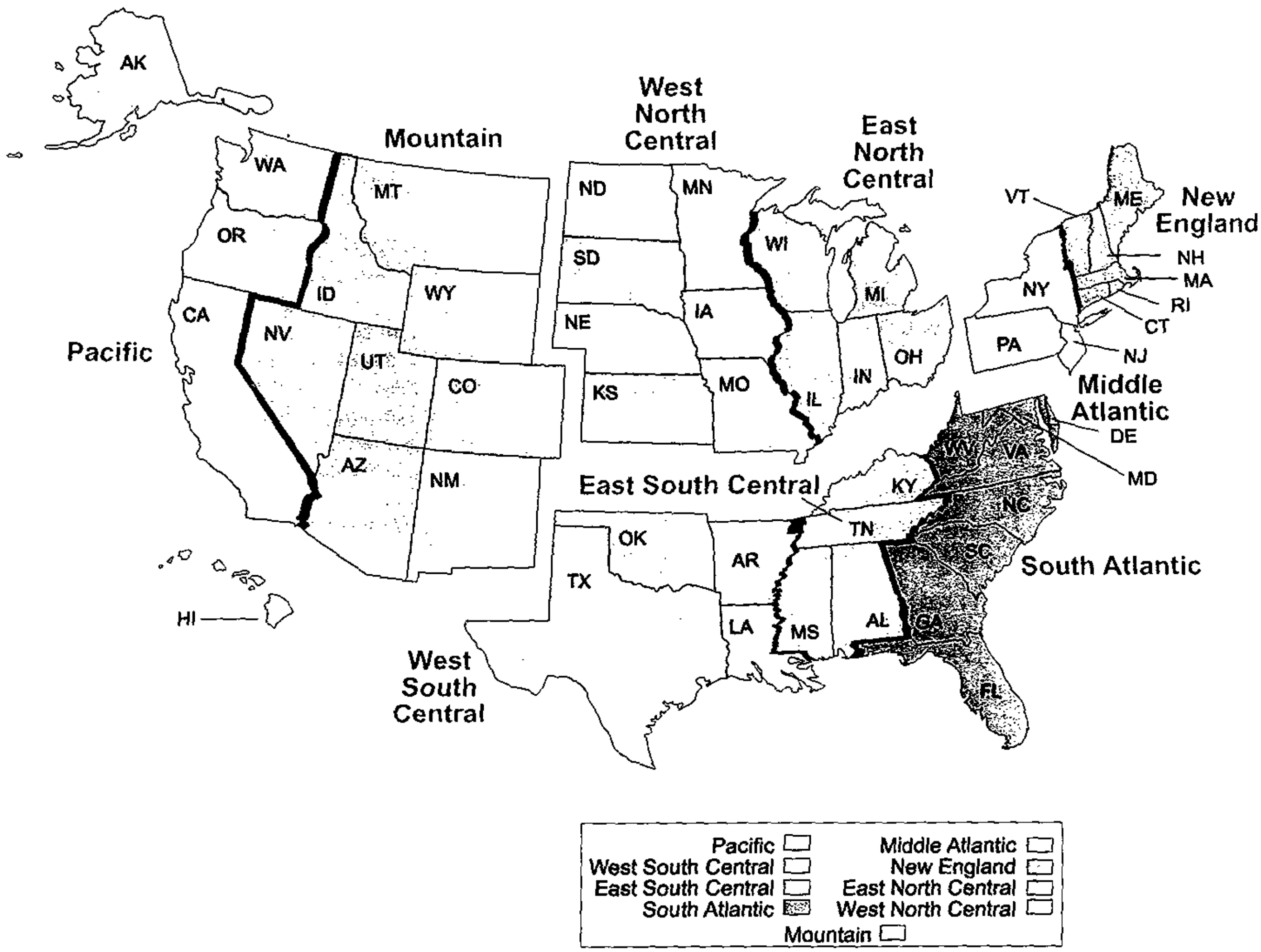
Appendix F

Regional Maps

Figure F1. United States Census Divisions



Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F1. United States Census Divisions (continued)

Division 1
New England

Connecticut
Maine
Massachusetts
New Hampshire
Rhode Island
Vermont

Division 2
Middle Atlantic

New Jersey
New York
Pennsylvania

Division 3
East North Central

Illinois
Indiana
Michigan
Ohio
Wisconsin

Division 4
West North Central

Iowa
Kansas
Minnesota
Missouri
Nebraska
North Dakota
South Dakota

Division 5
South Atlantic

Delaware
District of Columbia
Florida
Georgia
Maryland
North Carolina
South Carolina
Virginia
West Virginia

Division 6
East South Central

Alabama
Kentucky
Mississippi
Tennessee

Division 7
West South Central

Arkansas
Louisiana
Oklahoma
Texas

Division 8
Mountain

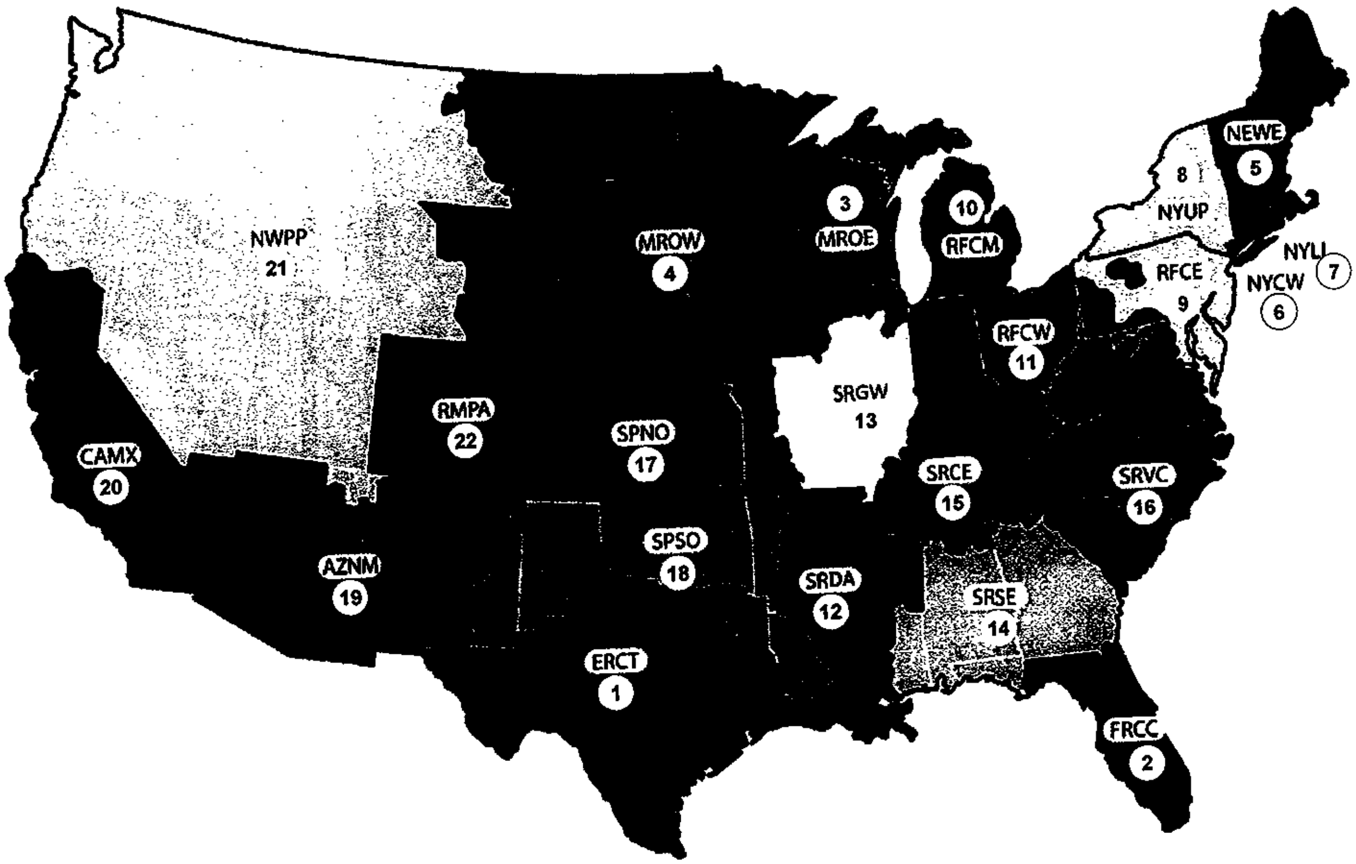
Arizona
Colorado
Idaho
Montana
Nevada
New Mexico
Utah
Wyoming

Division 9
Pacific

Alaska
California
Hawaii
Oregon
Washington

Source: U.S. Energy Information Administration, Office of Energy Analysis.

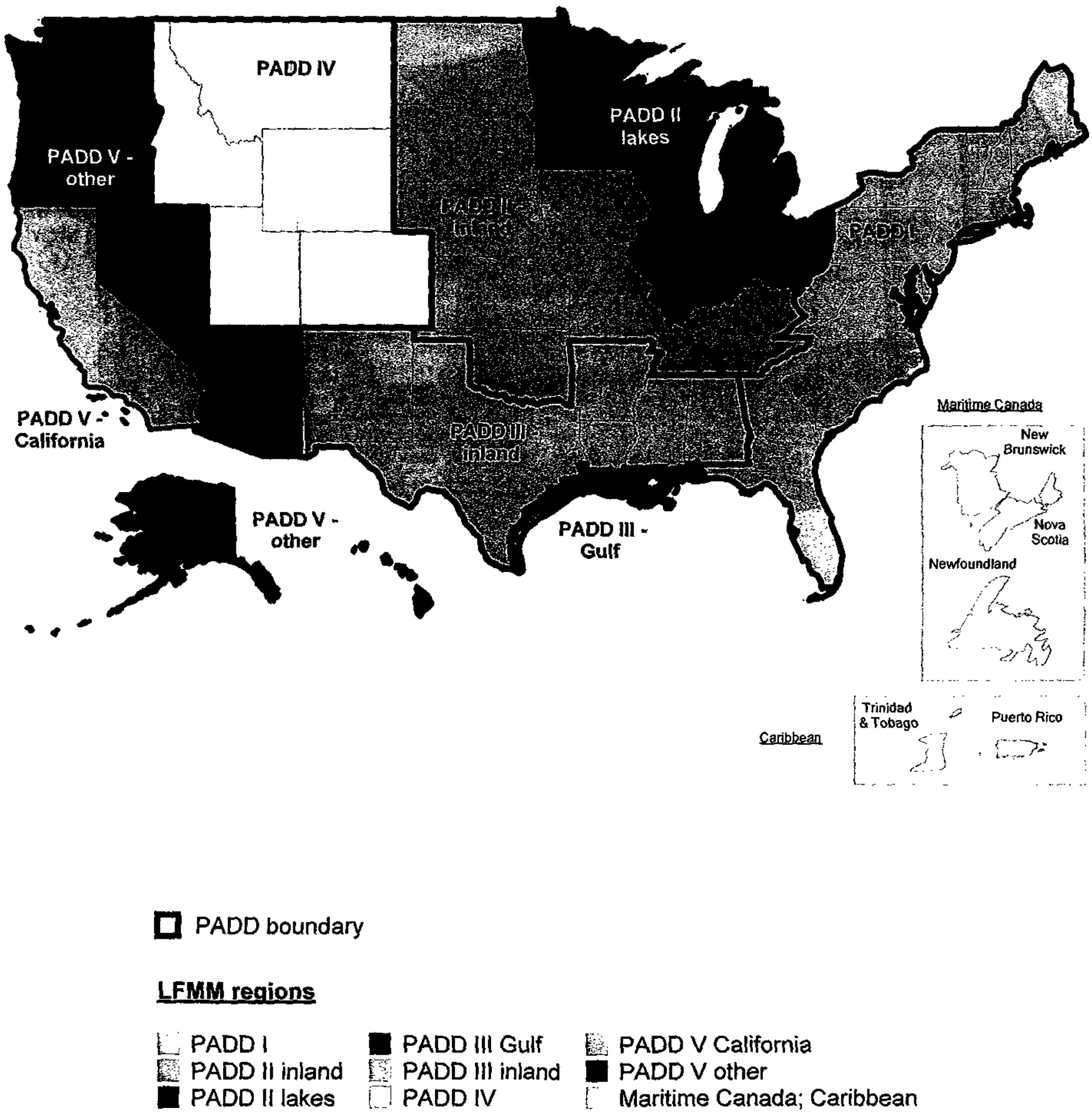
Figure F2. Electricity market module regions



1. ERCT TRE All
2. FRCC FRCC All
3. MROE MRO East
4. MROW MRO West
5. NEWE NPCC New England
6. NYCW NPCC NYC/Westchester
7. NYLI NPCC Long Island
8. NYUP NPCC Upstate NY
9. RFCE RFC East
10. RFCM RFC Michigan
11. RFCW RFC West
12. SRDA SERC Delta
13. SRGW SERC Gateway
14. SRSE SERC Southeastern
15. SRCE SERC Central
16. SRVC SERC VACAR
17. SPNO SPP North
18. SPSO SPP South
19. AZNM WECC Southwest
20. CAMX WECC California
21. NWPP WECC Northwest
22. RMPA WECC Rockies

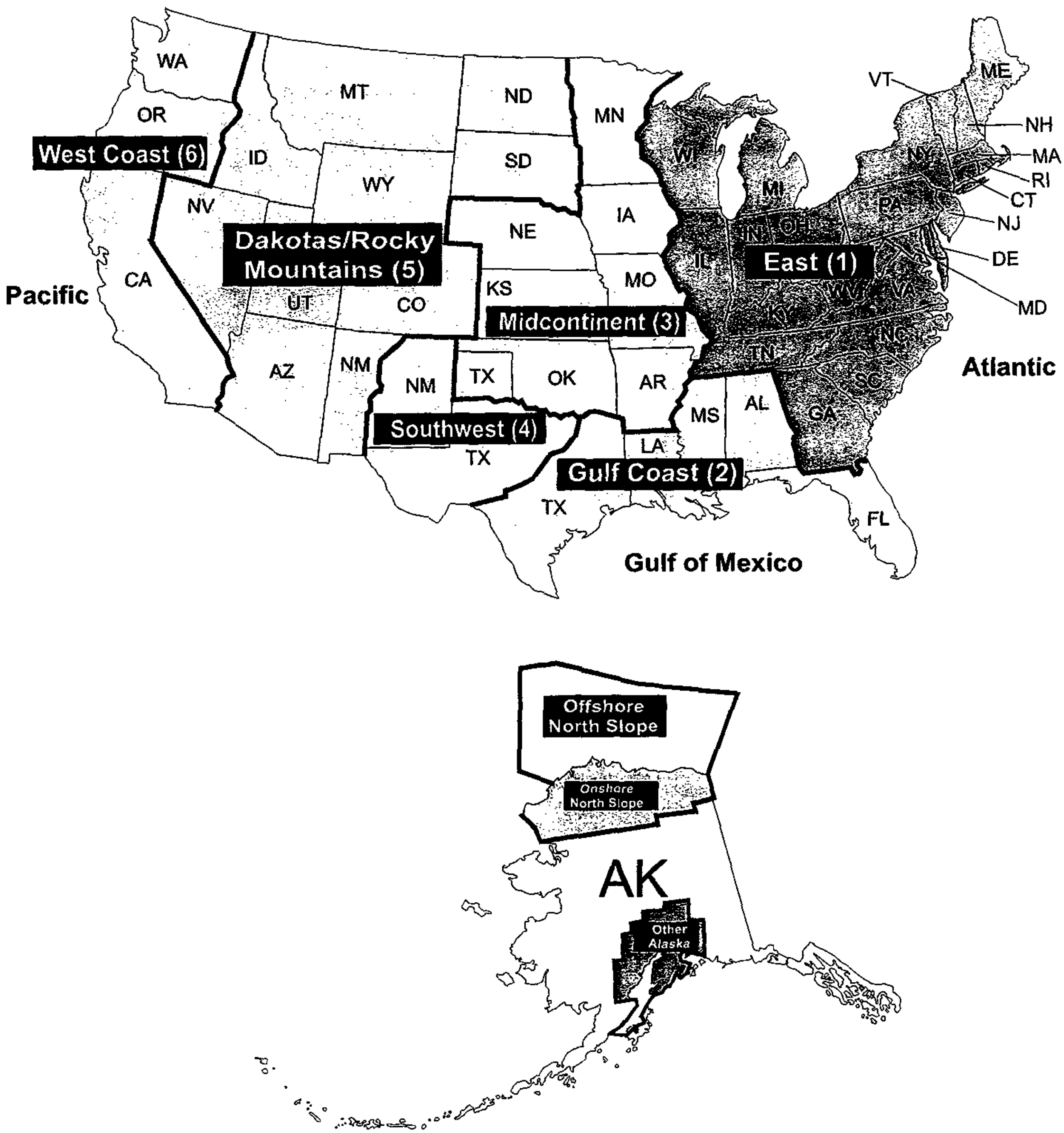
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F3. Liquid fuels market module regions



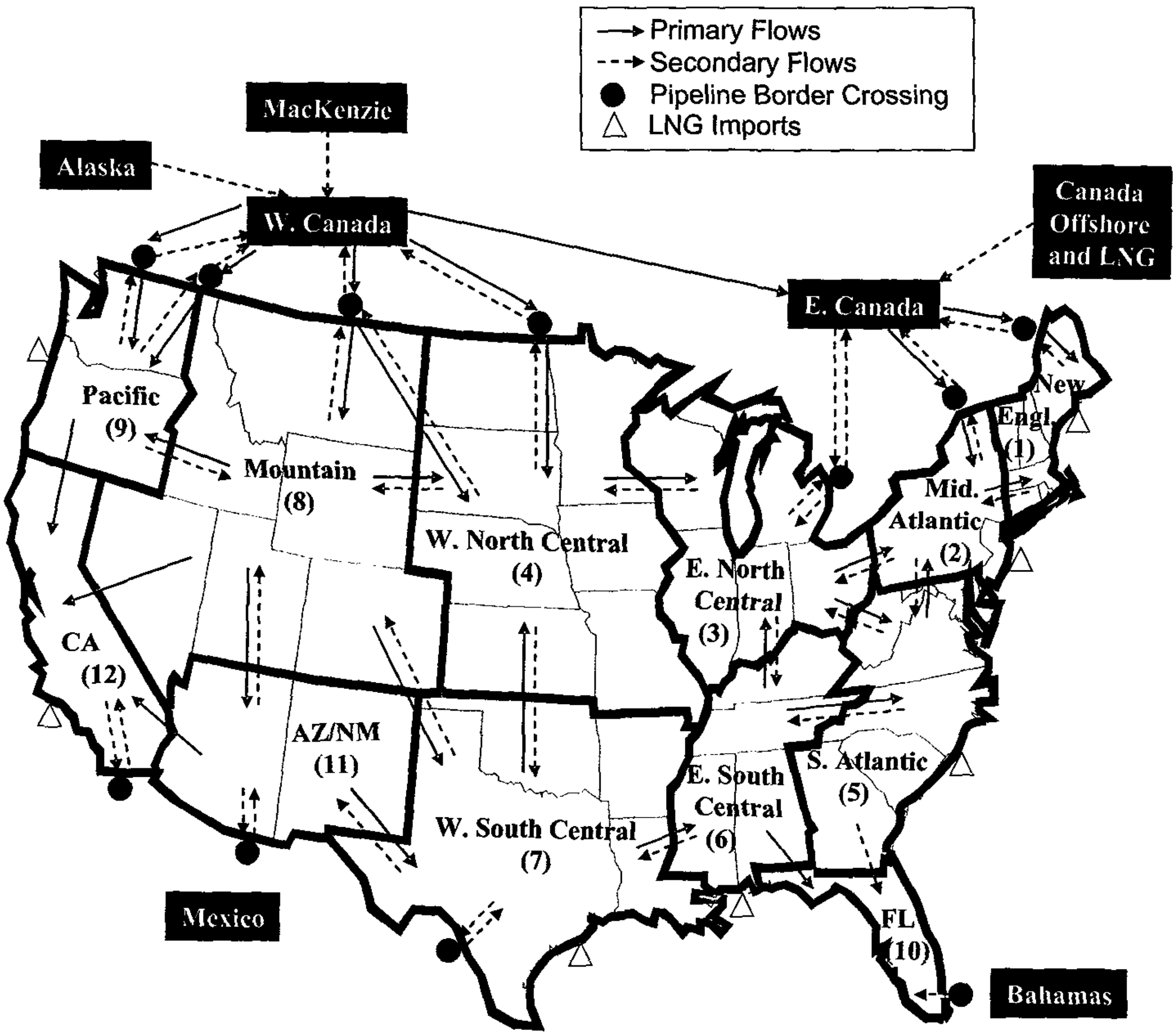
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F4. Oil and gas supply model regions



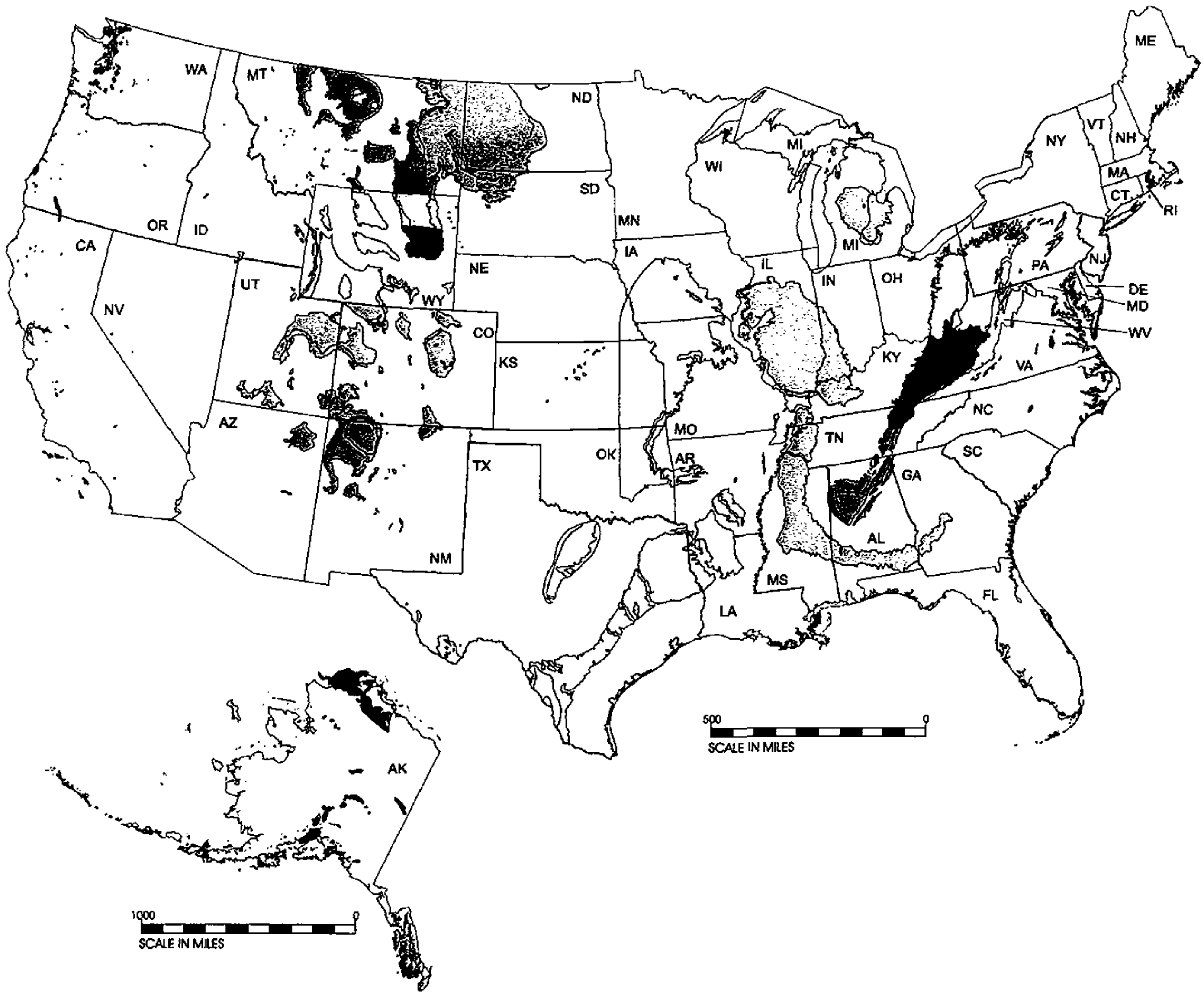
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F5. Natural gas transmission and distribution model regions



Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F6. Coal supply regions



APPALACHIA
- Northern Appalachia
- Central Appalachia
- Southern Appalachia

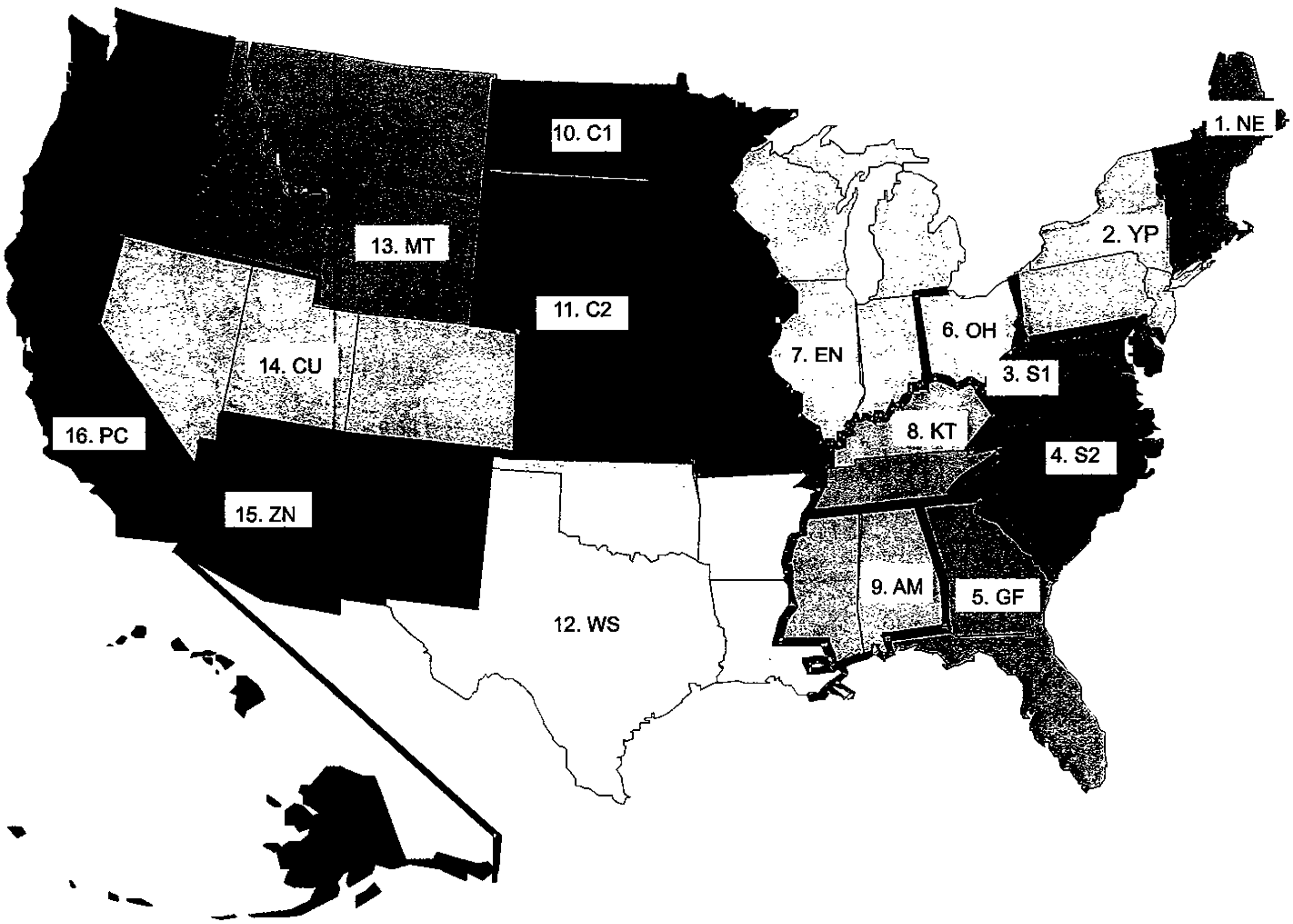
INTERIOR
- Eastern Interior
- Western Interior
- Gulf Lignite

NORTHERN GREAT PLAINS
- Dakota Lignite
- Western Montana
- Wyoming, Northern Powder River Basin
- Wyoming, Southern Powder River Basin
- Western Wyoming

OTHER WEST
- Rocky Mountain
- Southwest
- Northwest

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F7. Coal demand regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. S1	WV,MD,DC,DE
4. S2	VA,NC,SC
5. GF	GA,FL
6. OH	OH
7. EN	IN,IL,MI,WI
8. KT	KY,TN

Region Code	Region Content
9. AM	AL,MS
10. C1	MN,ND,SD
11. C2	IA,NE,MO,KS
12. WS	TX,LA,OK,AR
13. MT	MT,WY,ID
14. CU	CO,UT,NV
15. ZN	AZ,NM
16. PC	AK,HI,WA,OR,CA

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Conversion factors

Table G1. Heat contents

Fuel	Units	Approximate heat content
Coal[1]		
Production	million Btu per short ton	20.169
Consumption	million Btu per short ton	19.664
Coke plants	million Btu per short ton	28.710
Industrial	million Btu per short ton	21.622
Commercial and institutional	million Btu per short ton	21.246
Electric power sector	million Btu per short ton	19.210
Imports	million Btu per short ton	23.256
Exports	million Btu per short ton	24.562
Coal coke	million Btu per short ton	24.800
Crude oil[1]		
Production	million Btu per barrel	5.751
Imports	million Btu per barrel	6.012
Petroleum products and other liquids		
Consumption[1]	million Btu per barrel	5.188
Motor gasoline[1]	million Btu per barrel	5.101
Jet fuel	million Btu per barrel	5.670
Distillate fuel oil[1]	million Btu per barrel	5.760
Diesel fuel[1]	million Btu per barrel	5.755
Residual fuel oil	million Btu per barrel	6.287
Liquefied petroleum gases and other[1,2]	million Btu per barrel	3.565
Kerosene	million Btu per barrel	5.670
Petrochemical feedstocks[1]	million Btu per barrel	4.944
Unfinished oils[1]	million Btu per barrel	6.098
Imports[1]	million Btu per barrel	5.575
Exports[1]	million Btu per barrel	5.506
Ethanol[3]	million Btu per barrel	3.559
Biodiesel	million Btu per barrel	5.359
Natural gas plant liquids[1]		
Production	million Btu per barrel	3.735
Natural gas[1]		
Production, dry	Btu per cubic foot	1,027
Consumption	Btu per cubic foot	1,027
End-use sectors	Btu per cubic foot	1,028
Electric power sector	Btu per cubic foot	1,025
Imports	Btu per cubic foot	1,025
Exports	Btu per cubic foot	1,009
Electricity consumption	Btu per kilowatthour	3,412

[1]Conversion factor varies from year to year. The value shown is for 2013.
[2]Includes ethane, natural gasoline, and refinery olefins.
[3]Includes denaturant.
Btu = British thermal unit.
Sources: U.S. Energy Information Administration (EIA), *Monthly Energy Review*, DOE/EIA-0035(2014/11) (Washington, DC, November 2014), and EIA, AEO2015 National Energy Modeling System run REF2015.D021915A.

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CME Group
How the world advances

ON vs. LN User-Defined Spreads coming to CME Globex

Effective Sunday, August 16 (trade date Monday, August 17), CME Group is launching an enhancement to User-Defined Spreads (UDS) functionality to support the Henry Hub Natural Gas options complex on CME Globex.

With this launch, you will be able to create and trade spreads between American- and European-style options.

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Futures Options

Trade Date: Monday, 12 Oct 2015 (Final)

All market data contained within the CME Group website should be considered as a reference only and should not be used as validation against, nor as a complement to, real-time market data feeds.

Month	Open	High	Low	Last	Change	Settle	Estimated Volume	Prior Day Open Interest
NOV 15	2.520	2.559	2.510	2.543A	+.033	2.535	126,772	222,845
DEC 15	2.734	2.773	2.716	2.758	+.034	2.752	62,985	157,234
JAN 16	2.865	2.908	2.858	2.894	+.032	2.889	55,834	166,173
FEB 16	2.870	2.915	2.865	2.901	+.033	2.896	12,522	40,879
MAR 16	2.858	2.883	2.837	2.871	+.032	2.867	18,488	90,803
APR 16	2.730	2.744	2.715	2.741	+.027	2.739	12,245	69,253
MAY 16	2.760	2.760	2.727	2.750	+.025	2.749	2,407	25,665
JUN 16	2.767	2.784	2.760A	2.782B	+.024	2.785	1,163	26,098
JLY 16	2.813	2.823	2.803	2.821	+.023	2.824	846	21,342
AUG 16	2.821	2.833	2.817	2.830	+.023	2.833	400	16,272
SEP 16	2.816	2.827	2.804	2.825	+.023	2.827	968	14,559
OCT 16	2.839	2.852	2.827	2.849A	+.023	2.851	1,031	24,234
NOV 16	2.921	2.933	2.907	2.926	+.022	2.933	656	8,863
DEC 16	3.078	3.096	3.067	3.087B	+.020	3.094	447	10,185
JAN 17	3.193	3.193	3.177	3.188	+.023	3.192	391	13,842
FEB 17	3.175	3.179	3.175	3.179	+.021	3.183	39	3,528
MAR 17	3.105	3.107B	3.105	3.105	+.020	3.121	128	7,888
APR 17	2.885	2.885	2.883	2.884	+.016	2.882	143	7,286
MAY 17	-	2.865B	-	2.865B	+.016	2.872	23	2,505
JUN 17	2.901	2.901	2.901	2.901	+.016	2.907	9	2,590
JLY 17	-	-	-	-	+.015	2.944	5	1,903
AUG 17	-	-	-	-	+.015	2.959	5	1,975

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Month	Open	High	Low	Last	Change	Settle	Estimated Volume	Prior Day Open Interest
SEP 17	2.940	2.940	2.940	2.940	+.015	2.952	9	1,866
OCT 17	-	-	-	-	+.015	2.979	11	2,109
NOV 17	-	-	-	-	+.014	3.053	14	2,010
DEC 17	-	-	-	-	+.014	3.209	8	3,244
JAN 18	-	-	-	-	+.013	3.311	0	1,137
FEB 18	3.290	3.290	3.290	3.290	+.013	3.298	3	649
MAR 18	-	-	-	-	+.011	3.238	0	484
APR 18	-	2.928B	-	2.928B	+.015	2.928	0	458
MAY 18	-	-	-	-	+.015	2.919	0	363
JUN 18	-	-	-	-	+.015	2.951	0	473
JLY 18	-	-	-	-	+.015	2.986	0	399
AUG 18	-	-	-	-	+.015	3.001	0	361
SEP 18	2.995	2.995	2.995	2.995	+.015	2.993	1	335
OCT 18	-	-	-	-	+.015	3.018	0	524
NOV 18	-	-	-	-	+.015	3.096	0	275
DEC 18	-	-	-	-	+.015	3.254	0	1,226
JAN 19	3.362	3.362	3.362	3.362	+.015	3.364	5	679
FEB 19	-	-	-	-	+.015	3.349	0	384
MAR 19	-	-	-	-	+.015	3.291	0	379
APR 19	-	-	-	-	+.010	2.991	0	443
MAY 19	-	-	-	-	+.010	2.988	0	357
JUN 19	-	-	-	-	+.010	3.020	0	308
JLY 19	-	-	-	-	+.010	3.055	0	324
AUG 19	-	-	-	-	+.010	3.070	0	401
SEP 19	-	-	-	-	+.010	3.062	0	320
OCT 19	-	-	-	-	+.010	3.087	0	477
NOV 19	-	-	-	-	+.010	3.167	0	309
DEC 19	-	-	-	-	+.010	3.337	0	389
JAN 20	-	-	-	-	+.010	3.459	0	107
FEB 20	-	-	-	-	+.010	3.443	0	5
MAR 20	-	-	-	-	+.010	3.386	0	12
APR 20	-	-	-	-	+.005	3.096	0	72
MAY 20	-	-	-	-	+.005	3.095	0	22
JUN 20	-	-	-	-	+.005	3.123	0	19
JLY 20	-	-	-	-	+.005	3.152	0	62
AUG 20	-	-	-	-	+.005	3.176	0	11
SEP 20	-	-	-	-	+.005	3.171	0	12
OCT 20	-	-	-	-	+.005	3.202	0	3
NOV 20	-	-	-	-	+.005	3.282	0	2
DEC 20	-	-	-	-	+.005	3.460	0	228
JAN 21	-	-	-	-	+.005	3.588	0	30
FEB 21	-	-	-	-	+.005	3.572	0	30
MAR 21	-	-	-	-	+.005	3.515	0	30
APR 21	-	-	-	-	+.005	3.235	0	30

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Month	Open	High	Low	Last	Change	Settle	Estimated Volume	Prior Day Open Interest
MAY 21	-	-	-	-	+.005	3.230	0	31
JUN 21	-	-	-	-	+.005	3.260	0	30
JLY 21	-	-	-	-	+.005	3.297	0	30
AUG 21	-	-	-	-	+.005	3.327	0	30
SEP 21	-	-	-	-	+.005	3.326	0	30
OCT 21	-	-	-	-	+.005	3.362	0	31
NOV 21	-	-	-	-	+.005	3.442	0	30
DEC 21	-	-	-	-	+.005	3.620	0	30
JAN 22	-	-	-	-	+.005	3.745	0	0
FEB 22	-	-	-	-	+.005	3.727	0	0
MAR 22	-	-	-	-	+.005	3.669	0	1
APR 22	-	-	-	-	+.005	3.386	0	0
MAY 22	-	-	-	-	+.005	3.379	0	1
JUN 22	-	-	-	-	+.005	3.409	0	0
JLY 22	-	-	-	-	+.005	3.446	0	1
AUG 22	-	-	-	-	+.005	3.478	0	1
SEP 22	-	-	-	-	+.005	3.482	0	0
OCT 22	-	-	-	-	+.005	3.520	0	0
NOV 22	-	-	-	-	+.005	3.600	0	0
DEC 22	-	-	-	-	+.005	3.776	0	0
JAN 23	-	-	-	-	+.005	3.898	0	0
FEB 23	-	-	-	-	+.005	3.878	0	0
MAR 23	-	-	-	-	+.005	3.818	0	1
APR 23	-	-	-	-	+.005	3.530	0	0
MAY 23	-	-	-	-	+.005	3.521	0	1
JUN 23	-	-	-	-	+.005	3.551	0	0
JLY 23	-	-	-	-	+.005	3.589	0	0
AUG 23	-	-	-	-	+.005	3.625	0	0
SEP 23	-	-	-	-	+.005	3.635	0	0
OCT 23	-	-	-	-	+.005	3.683	0	4
NOV 23	-	-	-	-	+.005	3.763	0	0
DEC 23	-	-	-	-	+.005	3.943	0	0
JAN 24	-	-	-	-	+.005	4.058	0	0
FEB 24	-	-	-	-	+.005	4.038	0	0
MAR 24	-	-	-	-	+.005	3.978	0	0
APR 24	-	-	-	-	+.005	3.683	0	0
MAY 24	-	-	-	-	+.005	3.671	0	1
JUN 24	-	-	-	-	+.005	3.701	0	0
JLY 24	-	-	-	-	+.005	3.739	0	0
AUG 24	-	-	-	-	+.005	3.775	0	0
SEP 24	-	-	-	-	+.005	3.785	0	0
OCT 24	-	-	-	-	+.005	3.840	0	8
NOV 24	-	-	-	-	+.005	3.920	0	0
DEC 24	-	-	-	-	+.005	4.105	0	0

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Month	Open	High	Low	Last	Change	Settle	Estimated Volume	Prior Day Open Interest
JAN 25	-	-	-	-	+.005	4.220	0	0
FEB 25	-	-	-	-	+.005	4.198	0	0
MAR 25	-	-	-	-	+.005	4.133	0	0
APR 25	-	-	-	-	+.005	3.813	0	0
MAY 25	-	-	-	-	+.005	3.798	0	0
JUN 25	-	-	-	-	+.005	3.836	0	0
JLY 25	-	-	-	-	+.005	3.884	0	0
AUG 25	-	-	-	-	+.005	3.928	0	0
SEP 25	-	-	-	-	+.005	3.943	0	0
OCT 25	-	-	-	-	+.005	4.003	0	0
NOV 25	-	-	-	-	+.005	4.096	0	0
DEC 25	-	-	-	-	+.005	4.298	0	0
JAN 26	-	-	-	-	+.005	4.413	0	0
FEB 26	-	-	-	-	+.005	4.388	0	0
MAR 26	-	-	-	-	+.005	4.318	0	0
APR 26	-	-	-	-	+.005	3.958	0	0
MAY 26	-	-	-	-	+.005	3.943	0	0
JUN 26	-	-	-	-	+.005	3.981	0	0
JLY 26	-	-	-	-	+.005	4.029	0	0
AUG 26	-	-	-	-	+.005	4.073	0	0
SEP 26	-	-	-	-	+.005	4.088	0	0
OCT 26	-	-	-	-	+.005	4.148	0	0
NOV 26	-	-	-	-	+.005	4.263	0	0
DEC 26	-	-	-	-	+.005	4.488	0	0
JAN 27	-	-	-	-	+.005	4.608	0	0
FEB 27	-	-	-	-	+.005	4.583	0	0
MAR 27	-	-	-	-	+.005	4.508	0	0
APR 27	-	-	-	-	+.005	4.108	0	0
MAY 27	-	-	-	-	+.005	4.093	0	0
JUN 27	-	-	-	-	+.005	4.131	0	0
JLY 27	-	-	-	-	+.005	4.179	0	0
AUG 27	-	-	-	-	+.005	4.223	0	0
SEP 27	-	-	-	-	+.005	4.238	0	0
OCT 27	-	-	-	-	+.005	4.298	0	0
NOV 27	-	-	-	-	+.005	4.418	0	0
DEC 27	-	-	-	-	+.005	4.648	0	0
Total							297,558	957,541

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