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# THE ENERGY INFORMATION ADMINISTRATION'S ANNUAL ENERGY OUTLOOK FOR 2015

## HEARING

BEFORE THE

## COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

ONE HUNDRED FOURTEENTH CONGRESS

FIRST SESSION

ON

THE ENERGY INFORMATION ADMINISTRATION'S
ANNUAL ENERGY OUTLOOK FOR 2015

APRIL 16, 2015

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# THE ENERGY INFORMATION ADMINISTRATION'S ANNUAL ENERGY OUTLOOK FOR 2015

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**THURSDAY, APRIL 16, 2015**

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
*Washington, DC.*

The Committee met, pursuant to notice, at 10:06 a.m. in room SD–366, Dirksen Senate Office Building, Hon. Lisa Murkowski, Chairman of the Committee, presiding.

## OPENING STATEMENT OF HON. LISA MURKOWSKI, U.S. SENATOR FROM ALASKA

The CHAIRMAN. I call to order the meeting of the Energy Committee.

Good morning, everyone. I would like to welcome you, Mr. Sieminski, here to present on the Energy Information Administration's (EIA) Annual Energy Outlook for 2015.

Mr. Sieminski, you have appeared before the Committee many times. We appreciate your work. You have ably served as EIA's Administrator since June of 2012, and again, we are pleased to have you back before the Committee today.

The EIA, as we know, is an important agency and one that we take very seriously here on the Energy Committee. The volume, the breadth and the frequency of its many publications are very, very impressive.

The publication that brings us here today is the Annual Energy Outlook for 2015 which was released earlier this week. It is a lovely, glossy, thick, not too thick, very readable book with good charts and great information as well as the Executive summary that's in there—but it is chock full of good information.

It is my understanding that this is a projective document rather than a predictive one. In other words, you are not telling us what will happen in the future. Instead you are telling us what may happen in certain reference cases under certain assumptions.

This is a useful annual exercise. Over the past five years the EIA's projections in the Annual Energy Outlook have painted a picture of a brighter American future at least in the terms of energy.

So before we proceed to your testimony, Mr. Sieminski, I want to highlight two items from EIA's Executive Summary that I found interesting. I think that Committee members will, perhaps, have a number of questions on these items.

First, according to EIA we could see zero net energy imports in 2028 under the reference case or as early as the year 2019 in the high oil price and high oil and gas resources scenarios. I believe this is enormously good news for our nation. The projected zeroing out of our net energy imports portends a future in which the United States is a net energy exporter. It does not require much of an imagination to see how that will potentially enhance our geopolitical position around the world.

The second point is that EIA's report also recognizes the growth in crude oil and dry natural gas production vary significantly across regions. As a result increased investment or realignment of pipelines and other midstream infrastructure is necessary.

Now as we all know this Committee is working on a bipartisan energy bill. We will have both infrastructure and supply titles in that bill, along with titles on efficiency and accountability. It is my hope this morning in this hearing as we look at the Annual Energy Outlook that we will gain some numerical grounding to that effort and that EIA will continue to be a resource for the Committee going forward.

So, Mr. Sieminski, we look forward to your presentation on this annual report. Again, thank you for the good work that has led up to this point in time.

With that, I will turn to Senator Cantwell as the Ranking Member and then we will turn to you, Mr. Sieminski.

**STATEMENT OF HON. MARIA CANTWELL, U.S. SENATOR FROM WASHINGTON**

Senator CANTWELL. Thank you, Madam Chair, and thank you for this annual hearing and for the update.

Mr. Sieminski, thank you so much. It is a pleasure to be working with you on such an important issue. We are here today to look at the findings in this report.

First, I think it is important that the U.S. is likely to become less reliant on imported energy but will still remain a net oil importer for the entire forecast period. Within the context of the debate about current export policy, this is a key factor that we have to keep in mind.

Second, carbon pollution is still expected to increase, even while it remains below the 2005 levels. This highlights the fact that we must take steps to bend the curve even further downward, given the tremendous cost to our climate and what is already being imposed on businesses and communities in my state and around the country.

We need to look at policies where we can be mindful that these analyses, as my colleague just said, are predictive about what is happening right now, but not 100 percent certain about what is going to happen in the future. Keeping that in mind we need to increase energy efficiency, make it a larger variable in the equation and keep carbon pollution below the 2005 levels.

For example, carbon pollution from the residential sector is projected to decline by five percent from 2013 to 2040. These reductions come from appliance and building efficiencies, which more than offset the growth in the number of houses that will need to be heated and cooled. I know a lot of my colleagues appreciate that we can do much more to drive energy efficiency solutions into the marketplace, and it is a policy that ultimately pays for itself.

Another important finding in the report is that electricity prices are likely to increase because of fuel costs. In the reference case national electricity prices are projected to rise 18 percent between 2013 and 2040, and these price projections are driven by coal prices rising by nearly 25 percent and natural gas prices rising by 88 percent.

In contrast, the renewable generation technologies, which use wind and solar and fuel, are going to be comparatively less expensive, potentially seeing different technology costs dropping 10 to 20 percent. These projections don't even take into account the rapid technology changes that can further drive the cost curve down.

So it seems like sensible policies to me that we should still do more to connect these technologies to the electricity grid. Along those lines I should note that I do have an ongoing concern that EIA continually underestimates the potential of renewable energy in the Annual Energy Outlook report, but maybe that is something we can work on for the future.

In these projections renewables meet much of the growth in electricity demand. In fact, renewables are likely to become cost competitive in many regions in the coming years. According to the Department of Energy's own 2014 Revolution Now Report, "by 2014 roof top solar panels cost about one percent of what they did 35 years ago and solar PV installations were about 15 times what they were in 2008. So between 2008 and 2014 the cost of PV model declined from $3.40/watt to $0.79/watt."

Also in the same report DOE found a similar finding for wind. There seems to be an internal disconnect at the Department of Energy because other offices at DOE are noting how much better these technologies are performing than forecasted, and yet, EIA is predicting the same high-cost, low-growth scenarios.

So I cannot imagine your job, Mr. Sieminski, balancing all of these variables any time you have this many scenarios and trying to keep them all on a similar line of a level of whether it is now or in the future. Maybe we can talk again about how we get some of this in future reports.

Another example, as of the end of 2014, the American Wind Energy Association's market report reported that the United States had a wind capacity of over 65 gigawatts. Your 2013 report, just two years ago, projected that wind capacity wouldn't exceed 65 gigawatts until 2034. So in reality it happened 20 years before that.

Many organizations and associations have found that EIA's assumptions are lagging behind the real world when it comes to clean energy development, and these assumptions, if incorrect, drastically impact the projections of renewables and can paint a misleading picture about the power of renewables.

So while this EIA analysis is very useful, I think we need to take a holistic approach about how different energy sources are faring against others and the policies. This analysis is just one tool that helps us look at market predictions.

I am a very big supporter of EIA and actually want to enhance its capacity because I think in an information age energy policy is so important and you can play a role on so many different avenues. I think it is very important we continue to strengthen your office and organization, and I am sure we will get a chance to talk about it in the Q and A.

I would also like to commend the EIA on its announcement that effective in March it is now able to provide monthly data on rail movements of crude oil. I suspect that reaching an agreement with the U.S. Surface Transportation Board and Canada's National Energy Board to get this data were not a simple task. The data shows that over the past five years crude-by-rail shipments have increased 17 times nationally. Let me put it in the percentage. That's a 1,751 percent increase in the shipment of crude-by-rail. 20,000,000 barrels in 2010 to 370,000,000 barrels in 2014. That is, to say, a big impact on us in the Pacific Northwest. The hard facts make it clear the responsibility lies with policy makers to consider the public health and safety-related impacts of this emerging trend.

Neither the oil industry nor the rail industry should enjoy unfettered profits from the shale boom without being required to step up and make sure that they have the safety precautions in place for the kinds of rail explosions that we are seeing across America.

So once again, Mr. Sieminski, thank you and your staff so much for providing this information. I want to continue to work with EIA to make additional progress in this area.

One other thing I want to mention, a lingering concern about the data and analysis associated with another pressing topic before the Committee, namely the completeness of EIA's crude oil export analysis. In February 2014, Senator Wyden, who was the Chair of this Committee, and I joined to ask you for a comprehensive analysis of the regional price and transportation impacts on any change to current export policies. We live in a part of the country, Washington and Oregon, that depends on Alaska crude oil, and our market has been relatively isolated from the rest of the country.

I am sure my colleagues will remember that both Senator Wyden and I constantly talk about this issue.

We have to talk about it because we have some of the highest gasoline prices in the nation, and we are always asking why. Let's just say that now as we look at the discussion in a few weeks in our export hearing we want to understand more completely this issue. From what we have seen thus far in EIA's piecemeal analysis on crude oil exports, there has been no analysis on what this policy change might mean for consumers in the Pacific Northwest, who pay, as I said, among the highest gas prices. We also see headlines from other organizations suggesting that crude-by-rail traffic could double if the export ban is lifted. We need EIA to provide some enlightenment and additional analysis on this. I do not think Senator Wyden and I are satisfied with where we are, and we want to see this information as soon as possible.

Again, Madam Chair, thank you for holding this hearing. And again, Mr. Sieminski, we want more information. That is the bottom line, and we want to help build as robust an organization underneath you as we possibly can in an information age where this is such a vital, important issue to our country. Thank you.

The CHAIRMAN. Thank you, Senator Cantwell.

Mr. Sieminski, again, welcome to the Committee. We look forward to your comments this morning.

**STATEMENT OF HON. ADAM SIEMINSKI, ADMINISTRATOR, U.S. ENERGY INFORMATION ADMINISTRATION, U.S. DEPARTMENT OF ENERGY**

Mr. SIEMINSKI. Thank you very much, Chairman Murkowski, Ranking Member Cantwell, Senator Manchin, Senator Gardner. It's a pleasure to be here. I really appreciate the opportunity to talk about the Annual Energy Outlook.

And I'd like to start off with a request. I hope it would be okay if I would run over by two or three minutes of the five minute allocation in trying to summarize that.

Thank you.

The CHAIRMAN. Absolutely. We don't have to turn to anybody else on the panel——

[Laughter.]

Mr. SIEMINSKI. The second thing that I would like to say is that when I appeared before this Committee in early 2012 during my confirmation hearing I mentioned a number of things that I thought that EIA needed to do. And one of those was to do crude-by-rail information. Another one was to have much better, more timely data on the production of light, tight oil in the United States.

And EIA has delivered on both of those promises. And we have a few more things that we're working on but in general, I think, that the flow of information is pretty good.

EIA is the statistical and analytical agency within the Department of Energy. And by law, EIA's data and analyses are independent of approval by any other Federal office. So my remarks today really represent EIA and not the Department of Energy or any other Federal agency.

I'd like to start off with just a few comments about the short term energy outlook. What's happening in the global oil markets, in particular. And then discuss the recently released Annual Energy Outlook in more detail.

In the short run EIA is expecting generally rising crude oil prices over the next few years. But we recognize the very high uncertainty as reflected in recent transactions in the futures and options markets. EIA forecasts that Brent crude oil which is a global water borne bench-mark will average about $59 in 2015 and $75 a barrel in 2016.

West Texas Intermediate or WTI crude, the land-locked U.S. bench-mark is expected to continue to sell at a $5 to $7 discount to Brent.

Some of the key factors in the near term pricing uncertainty include the global economic outlook, what's happening in China, especially. And geopolitical issues affecting supply in countries as diverse as Venezuela where the economic situation is really bad and Iran where the nuclear talks are underway and might result in a lifting of sanctions. And this could have big impacts on the availability of oil in the global markets.

Total domestic crude oil production averaged about 8.7 million barrels a day in 2014. We think that it hit close to 9.2 million barrels a day in the last quarter of 2014, but should be relatively flat in 2015 then rising to 9.3 million barrels a day in 2016. EIA expects drilling activity to begin to increase in the second half of 2015 as companies respond to somewhat higher prices and lower costs for leasing, drilling and completion.

On the consumer side there's some really good news from lower oil prices. This should save the average household something like $700 in 2015 compared to 2014. U.S. average regular gasoline prices at the retail level, about $2.40 or so now, are expected to remain near that level through the summer and might hit $2.75 or so next year.

Natural gas storage and working inventories are in much better shape at the end of this winter than they were last winter. And EIA projects that natural gas inventories will end October 2015 looking out towards the end of this year at nearly 3.8 trillion cubic feet following an injection season that's expected to be the fourth highest on record.

Natural gas spot prices averaged just under $4.40 a million BTUs in 2014. And we think that that number will be down closer to $3.10 a million BTU in 2015. And still under $3.50 in 2016.

That's pretty good news for consumers in the mid part of the United States that depend on natural gas for heating fuel. Primarily because lower natural gas prices relative to coal prices generators are using more natural gas than they were last year. Natural gas' share of generation is projected to be 30.4 percent of total generation this year compared to 27.4 last year. The share of coal fueled generation is forecast to be down about three percentage points from about 39 to 36 percent in 2015.

EIA expects the share of total electricity generation from renewables, all renewables, including hydropower to increase from 13 percent in 2014 to a little over 14 percent in 2016 with wind alone providing more than 5.2 percent of total generation.

I'm going to turn now to the Annual Energy Outlook which provides longer term projections focused on factors that shape U.S. energy markets through 2040 under the assumption that current laws and regulations remain unchanged throughout the projection period. Consistent with this approach neither EPA's proposed Clean Power Plant rules for existing fossil fired electric generating units, nor the effects of possible changes in current limits on crude oil exports are considered. These topics will be addressed in two forthcoming EIA reports.

Senator Cantwell, let me just mention very quickly that using the assumption that current law and regulations remains in place, generally tends to underplay EIA's forecasts for renewables simply because of the positive impact on renewables that come from the tax credits and other Federal incentives. And since we allow those to sunset as they do in existing law, it shows lower numbers in the reference case. If you look at our no sunset cases, which assumes continuation of the tax incentives, the results are in line with the recent experience of short term extensions.

The AEO reference case and the five alternative cases really do provide a good basis for examination and discussion of energy market trends. And they serve as a starting point for the analysis of potential changes in U.S. energy policies.

I don't have any doubt at all that there are going to be big differences with our forecast for what 2040 looks like and what will really be the case in 2040. But it's super, super helpful to have a reference case against which you can test changes in law and regulation and changes in the economy, changes in oil and gas and other prices to see what the sensitivities are. It's really important we do that.

In the reference case Brent crude oil rises steadily after 2015 in response to global oil demand and keeps moving. The variation prices that we show in the AEO is quite wide. There's a high case of oil getting to $252 a barrel by 2040, a low case of $76 a barrel.

I think of these as stress tests. It's not that we really believe that oil is going to go to $250 a barrel, but we want to look at what happens in the economy if we were to have such an event take place.

Figure two in my testimony shows net energy imports aggregated across all fuels. And that's the point that we were making earlier. In our reference case net energy imports cross over at around 2028 to zero net energy imports.

Most of the heavy lifting in those numbers occurs actually in the period running up to 2020. So it's possible that the U.S. could become a zero net importer of energy even sooner than the reference case numbers. A lot depends on geopolitical events and what happens in the markets, what happens with the economy.

Strong growth in domestic crude oil production from tight formation leads to a decline in petroleum imports in all of the cases. In the reference case, the U.S. is importing about 20 percent of its consumption in 2015. That's in contrast to 60 percent of demand for liquid fuels being met by imports back in 2005. It was only ten years ago.

The possibility, that with higher oil prices or a high oil and gas resource case, that the U.S. would become a net exporter of total liquids is a real one.

Turning to natural gas.

Prices in the U.S. market are mainly influenced by domestic resource availability and technology. They're also affected by world energy prices and natural gas demand. In the reference case, the Henry Hub price rises to nearly $5 a million BTU in 2020 and to nearly $8 a million BTU in 2040 as increased demand in domestic and international markets leads to the production of increasingly expensive resources.

In alternative cases the Henry Hub price could be substantially lower, $3 a million BTU in 2020, 36 below the reference case. That would be if we simply find more oil and natural gas than is in our reference case.

Beyond 2020 prices vary across the different cases, closer well spacing, greater technology than the reference case that give significantly lower numbers for gas prices and to oil prices as well than are in our reference case.

Figure four in my testimony shows exports of liquefied natural gas in the reference case, the high oil and gas resources case, in the low oil price case, that natural gas trade including LNG exports depends largely on the effects of resource levels and world energy prices. In all cases, as we show in the testimony, the United

States transitions from being a net importer of natural gas to a net exporter by 2017.

Senator Murkowski said that we would be a zero importer before the end of the next decade and that growth differences across regions were important. And Senator Murkowski, we do find that regional variations in domestic crude oil production and natural gas production could drive significant changes in flows between regions requiring an investment or realignment in things like pipelines and other midstream infrastructure.

Some of the biggest differences in the high oil and gas resource case, for example, are a lot more oil in the Dakotas and Rocky Mountains area that requires transportation out to refineries and markets and a lot more production potentially of natural gas in places like Pennsylvania, Ohio and West Virginia that would require the movement of gas out of those regions.

Figure six in my testimony shows manufacturing output, where all of the growth in natural gas goes that the United States is going to see, in our view, over the next 25 years or so. Both chemicals industry, the food processing industry, the refining industry and metal smelting, would all be beneficiaries of this growth in natural gas production.

Figure seven in my testimony talks about the rise in electricity prices and increasing with rising fuel costs. The—one of the key things there is that electricity demand itself is not growing very much, only by about eight tenths of a percent per year. And as a consequence it's very hard for new fuels, like renewables, to penetrate the electric markets. Although renewables are growing quite substantially in EIA's forecast, it's still very hard for renewables to compete against some of the established, coal, nuclear and natural gas base load plants.

Rising costs for electric power generation, transmission distribution coupled with relatively slow growth of electricity demand lead to an 18 percent increase in average retail prices in the reference case over the period. And we see that in virtually all of our cases.

I'm going to conclude on just a couple of comments concerning growth in wind and solar generation.

By the end of the forecast period even with the existing law and regulation constraint that we have in the Annual Energy Outlook, wind power generation exceeds power from traditional hydropower by the end of the forecast period. And across all of the cases wind and solar generation meet a significant portion of the projected growth in total electricity load. So to the extent that electricity demand would rise faster there could even be more room for things like renewables generation. We'll just have to see how that works out.

A final comment on carbon dioxide emissions.

$CO_2$ emissions are very sensitive to the influence of future economic growth assumptions and energy price trends. They vary across all of our cases. In the reference case, however, carbon dioxide emissions remain below 5.5 billion metric tons, well below the peak of six billion metric tons that was reached back in 2005, 6 and 7. And they shift away from more carbon intensive fuels, especially for electric power does help to stabilize those numbers.

The last comment I would make and I appreciate the extra time very much, Senator, is that this is a shorter edition of the Annual Energy Outlook. It was completed under a new two year cycle.

The reason I bring this up is that is that by doing a somewhat shorter version every two years it enables us to use those resources, people, time and money, on doing an international energy outlook in the international energy outlook is increasingly important in trying to understand what's happening in the United States. Most of the energy growth globally is going to be occurring outside of the developed economies and it's critical that EIA do more work in the international area. And we're finding ways within our existing budget to do that.

I'd like to thank you very, very much for the opportunity to be here this morning. And I look forward to your questions.

Thank you.

[The prepared statement of Mr. Sieminski follows:]

**STATEMENT OF ADAM SIEMINSKI**

**ADMINISTRATOR**

**U.S. ENERGY INFORMATION ADMINISTRATION**

**U.S. DEPARTMENT OF ENERGY**

**BEFORE THE**

**COMMITTEE ON ENERGY AND NATURAL RESOURCES**

**UNITED STATES SENATE**

**APRIL 16, 2015**

Chairman Murkowski, Ranking Member Cantwell and Members of the Committee, I appreciate the opportunity to appear before you today to provide testimony on the U.S. energy outlook.

The U.S. Energy Information Administration (EIA) is the statistical and analytical agency within the U.S. Department of Energy. EIA collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding regarding energy and its interaction with the economy and the environment. EIA is the Nation's primary source of energy information and, by law, its data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views expressed in our reports, therefore, should not be construed as representing those of the Department of Energy or other federal agencies.

The energy information and projections that I will discuss today are widely used by government agencies, the private sector, and academia as a starting point for their own energy analyses. For the U.S. energy sector, EIA prepares both short-term energy outlooks, examining monthly trends over the next one to two years, and long-term outlooks, with annual projections over the next 20-to-25 years. I will summarize some key findings from our April *Short-Term Energy Outlook* (STEO) and the recently released *Annual Energy Outlook 2015* (AEO2015).

**The short-term energy outlook**

***Crude oil prices are projected to increase over next two years***

Recent values of futures and options contracts suggest very high uncertainty in the price outlook – the implied 95% confidence interval for market expectations for West Texas Intermediate (WTI) prices in December 2015 calculated for the current STEO ranges from $32/barrel (b) to $97/b. In EIA's latest monthly outlook, WTI prices in 2015 and 2016 are expected to average $7/b and $5/b, respectively, below the global waterborne market North Sea Brent, which is forecast to average $59/b in 2015 and $75/b in 2016. The projected discount of WTI crude oil to Brent, which fell with the decline in oil prices in 2014, has widened in recent months reflecting continuing large builds in U.S. crude oil inventories, including at the Cushing, Oklahoma storage hub.

On April 2, Iran and the five permanent members of the United Nations Security Council plus Germany (P5 +1) reached a framework agreement that could result in the lifting of oil related sanctions against Iran, which in turn could significantly change EIA's outlook for oil supply, demand, and prices. If and when sanctions are lifted, EIA's baseline forecast for world crude oil prices in 2016 could be reduced $5-$15/b from the level presented in EIA's April STEO.

***U.S. crude oil production to remain relatively flat in 2015 and 2016***

Total U.S. crude oil production, which averaged 8.7 million barrels/day (b/d) in 2014, is estimated to have averaged 9.3 million b/d in March, the same as in December 2014. Given

EIA's price forecast, projected total crude oil production averages 9.2 million b/d in 2015 and 9.3 million b/d in 2016. EIA expects onshore production to decline from June through September 2015 because of unattractive economic returns in some areas of both emerging and mature oil producing regions. Under EIA's baseline forecast of rising WTI crude oil prices during the second half of 2015, drilling activity is expected to increase again as companies take advantage of lower costs for leasing, drilling, and well completion services, resulting in a resumption of production growth in the fourth quarter.

***Total liquids consumption increases through 2016***

Total U.S. liquid fuels consumption fell from an average 20.8 million b/d in 2005 to 19.0 million b/d in 2014. EIA expects total consumption to rise slowly through 2016 to an average of 19.5 million b/d, driven by an increase in consumption of distillate fuel and gasoline, with jet fuel remaining flat.

***Lower gasoline prices expected to save average household $700 in 2015 compared with 2014***

U.S. average regular gasoline retail prices averaged $2.46/gallon (gal) in March, and are expected to remain near that level through the summer. EIA expects U.S. regular gasoline retail prices, which averaged $3.36/gal in 2014, to average $2.40/gal in 2015 and $2.73/gal in 2016. The average household is expected to spend $700 less for gasoline in 2015 compared with last year because of lower gasoline prices. Differences from EIA's baseline forecast in crude oil prices, which as noted above are subject to a wide range of market expectations, or in refinery margins would be reflected in pump prices. Additionally, prices for gasoline and other petroleum products are very sensitive to unplanned refinery outages, and any sudden loss of gasoline supply from the market could cause gasoline prices to be higher than forecast.

***Natural gas prices remain below 2014 levels in both 2015 and 2016***

Natural gas storage in working inventories was 1,461 billion cubic feet (Bcf) on March 27, which was 75% higher than a year earlier, but 12% lower than the previous five-year (2010-14) average. EIA projects natural gas inventories will end October 2015 at 3,781 Bcf, a net injection of 2,310 Bcf. This would be the fourth-highest injection season on record, but it would be 420 Bcf lower than last year's net March–October injection. EIA expects the Henry Hub natural gas spot price, which averaged $4.39/million British thermal units (Btu) in 2014, to average $3.07/million Btu in 2015 and $3.45/million Btu in 2016.

***Natural gas share of electric power generation expected to increase over 2014 level, reflecting lower natural gas prices***

Power generators are using more natural gas than last year, primarily because of lower natural gas prices relative to coal prices. The use of natural-gas-fired generation is projected to average 30.4% of total generation in 2015 compared with 27.4% during 2014. In contrast, the share of total generation fueled by coal falls from 38.7% in 2014 to 35.8% in 2015.

***Generation from renewable sources continues to rise***

EIA expects the share of total electricity generation from all renewables to increase from 13.0% in 2014 to 14.2% in 2016. Total renewables used for electricity and heat generation grow by

3.4% in 2015, as a result of 6.3% growth in conventional hydropower generation and 1.9% growth in non-hydropower renewables generation. In 2016, total renewables consumption for electric power and heat generation increases by an additional 2.6% as a result of a 5.2% increase in non-hydropower renewables, partially offset by a 2.5% decline in conventional hydropower generation. Wind is the largest source of non-hydropower renewable generation, contributing 5.2% to total electricity generation in 2016.

**Long-term energy outlook**

Projections in the *Annual Energy Outlook 2015* (AEO2015) focus on the factors that shape U.S. energy markets through 2040 under the assumption that current laws and regulations remain generally unchanged throughout the projection period. Consistent with this approach, EPA's proposed Clean Power Plan rules for existing fossil-fired electric generating units or the effects of possible changes in current limits on crude oil exports are not considered in AEO2015. These topics will be addressed in two forthcoming EIA reports.

The AEO2015 discusses the Reference and five alternative cases (Low and High Economic Growth, Low and High Oil Prices, and a High Oil and Gas Resource). The AEO2015 cases provide the basis for examination and discussion of energy market trends and serves as a starting point for analysis of potential changes in U.S. energy policies, rules, or regulations or potential technology breakthroughs. AEO2015 is a shorter edition of the AEO completed under a newly-adopted two-year release cycle that alternates full editions containing a broader complement of side cases and "issues in focus" discussions with shorter editions in order to free up resources in order to provide more current energy content in publications such as *Today in Energy* and the *Drilling Productivity Report* and to improve EIA's capability to address international data and market linkages which are increasingly important to domestic energy market developments and other topics of interest to policymakers. EIA will also be releasing a more extensive International Energy Outlook (IEO) later this year.

Major highlights in the AEO2015 include:

***AEO2015 considers a wide range of future crude oil price paths***

AEO2015 recognizes the uncertainty of future crude oil prices, which are driven by numerous factors including changes in worldwide demand for petroleum products, crude oil production, and supplies of other liquid fuels. In the AEO2015 Reference case, the price of global marker Brent crude oil rises steadily after 2015 in response to growth in global oil demand; however, downward price pressure from rising U.S. crude oil production keeps the Brent price below $80/b (in 2013 dollars)[1] through 2020. U.S. crude oil production starts to decline after 2020, but increased output from non-OECD and OPEC producers helps to keep the Brent price below $100/b through most of the next decade and limits price increases through 2040, when Brent reaches roughly $140/b.

[1] Unlike EIA's short-term outlook, which reports prices in nominal dollars, all prices in AEO2015 are reported in year 2013 dollars to avoid confusion between trends in real energy prices and general inflation.

There is significant oil price variation in the alternative cases considered in the AEO2015 (Figure 1). In the Low Oil Price case, the Brent price is $52/b in 2015 and reaches $76/b in 2040. In the High Oil Price case, the Brent price reaches $252/b in 2040. In the High Oil and Gas Resource case, with significantly more U.S. production than the Reference case, Brent is under $130/b in 2040, more than $10/b below its Reference case price.

***U.S. net energy imports, aggregated across all fuels, decline and ultimately end in most AEO2015 cases.***

Aggregate net energy imports decline to zero before 2030 in the AEO2015 Reference case and before 2020 in the High Oil Price and High Oil and Gas Resource cases (Figure 2). Significant net energy imports persist only in the Low Oil Price and High Economic Growth cases, where U.S. supply is lower and demand is higher. The decline in net energy imports is driven by growth in U.S. energy production—led by crude oil and natural gas—increased use of renewables, and only modest growth in demand.

***Continued strong growth in domestic tight oil production reduces and possibly eliminates net liquid fuel imports***.

Through 2020, strong growth in domestic crude oil production from tight formations leads to a decline in net petroleum imports and growth in condensate and product exports in all AEO2015 cases. The net import share of petroleum and other liquid products supplied falls from 26% in 2014 to 15% in 2025 and then rises slightly to 17% in 2040 in the Reference case (Figure 3). With greater U.S. crude oil production in the High Oil Price and High Oil and Gas Resource cases, the United States becomes a net petroleum exporter after 2020.

***Future natural gas prices will be influenced by a number of factors, including global energy prices, resource availability, and demand for natural gas***

Projections of natural gas prices are influenced by assumptions about world energy prices, resource availability, and natural gas demand. In the Reference case, the Henry Hub natural gas spot price rises to $4.88/million Btu in 2020 and to $7.85/million Btu in 2040, 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, and highest in the High Oil Price case, which assumes the same level of resource availability as the AEO2015 Reference case, but much higher oil prices. In the High Oil and Gas Resource case, the Henry Hub natural gas spot price is $3.12/million Btu in 2020 (36% below the Reference case price), rising to $4.38/million Btu in 2040 (44% below the Reference case price). In the High Oil Price case, which assumes the same resource scenario as the reference 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% above the Reference case price.

***Net natural gas trade, including LNG exports, depends largely on the effects of resource levels and world energy prices.***

The United States transitions from being a net importer of natural gas to a net exporter by 2017 in all cases. U.S. export growth continues after 2017, with annual 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 (Figure 4).

***Regional variations in domestic crude oil and natural gas production can force significant shifts in flows between regions, requiring investment in or realignment of pipelines and other midstream infrastructure.***

In most AEO2015 cases, lower 48 crude oil production shows the strongest growth in the Dakotas/Rocky Mountains region, followed by the Southwest region (Figure 5). The strongest growth of natural gas production occurs in the East region, followed by the Gulf Coast onshore and the Dakotas/Rocky Mountains regions. Interregional flows to serve downstream markets vary significantly among the cases.

***Technology and policy promote slower growth of energy demand.***

U.S. energy use grows modestly, at an annual rate of 0.3%/year from 2013 through 2040 in the Reference case, far below the rates of economic growth (2.4%/year) and population growth (0.7%/year). Decreases in transportation and residential sector energy consumption partially offset growth in other sectors. Declines in energy use reflect the use of more energy-efficient technologies and existing policies that promote increased energy efficiency. Fuel economy standards and changing driver behavior keep motor gasoline consumption below recent levels through 2040 in the Reference case. Diesel consumption, however, does rise over the period.

***Industrial energy use rises with growth of shale gas supply***

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 feedstocks (Figure 6).

***Electricity prices increase with rising fuel costs and expenditures on electric transmission and distribution infrastructure***

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 (Figure 7).

***Renewables meet much of the growth in electricity demand***

Continued growth in renewable electricity production—combined with slower growth in electricity demand, rising natural gas prices, and fewer nuclear retirements—leads to relatively limited growth in natural gas use for electricity generation. (Figure 8).

***Energy-related carbon dioxide emissions stabilize with lower energy and carbon intensity***. Improved efficiency in the end-use sectors and a shift away from more carbon-intensive fuels, especially for electric power, help to stabilize U.S. energy-related carbon dioxide ($CO_2$) emissions, which remain below the 2005 level through 2040 (Figure 9).

**Conclusion**

As I noted at the outset, while EIA does not take policy positions, its data, analyses, and projections are meant to assist energy policymakers in their deliberations. In addition to the work on the projections that I have reviewed this morning, EIA has often responded to requests from this Committee and others for analyses of the energy and economic impacts of energy policy proposals.

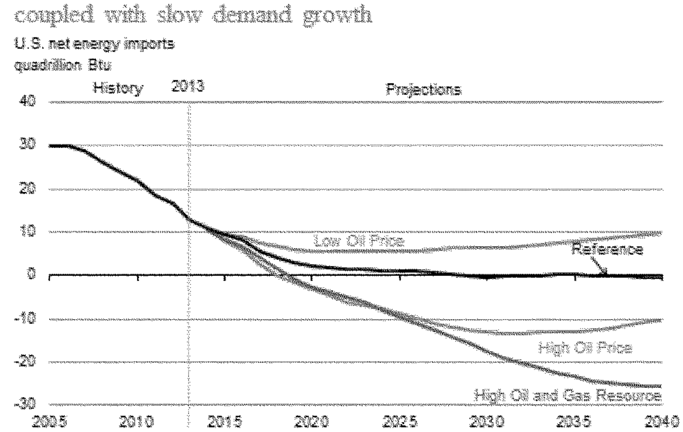
This concludes my testimony, Madam Chairman and Members of the Committee. I would be happy to answer any questions you may have.

Figure 1. AEO2015 explores scenarios that encompass a wide range of future crude oil price paths


Source: EIA, Annual Energy Outlook 2015

Annual Energy Outlook 2015, April 14, 2015 — 1

Figure 2. U.S. net energy imports continue to decline in the near term, reflecting increased oil and natural gas production coupled with slow demand growth




Source: EIA, Annual Energy Outlook 2015

Annual Energy Outlook 2015, April 14, 2015 — 2

Figure 3. Net imports provide a declining share of U.S. liquid fuels supply in most AEO2015 cases; in two cases the nation becomes a net exporter

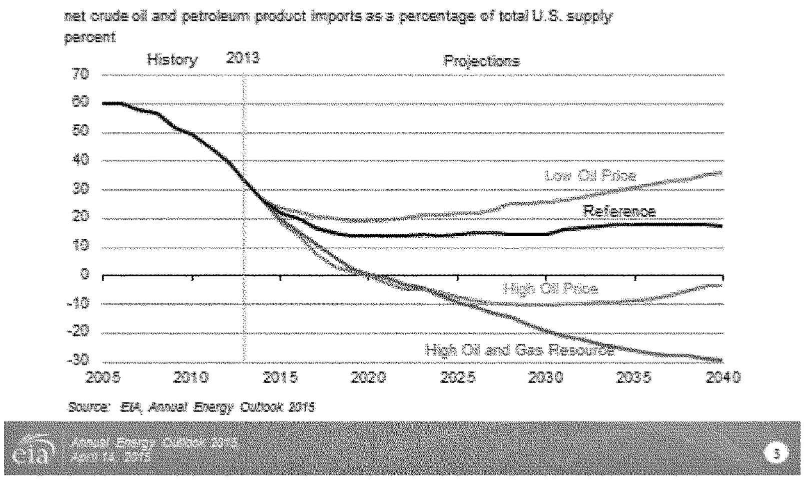



Figure 4. Projected U.S. natural gas exports reflect the spread between domestic natural gas prices and world energy prices

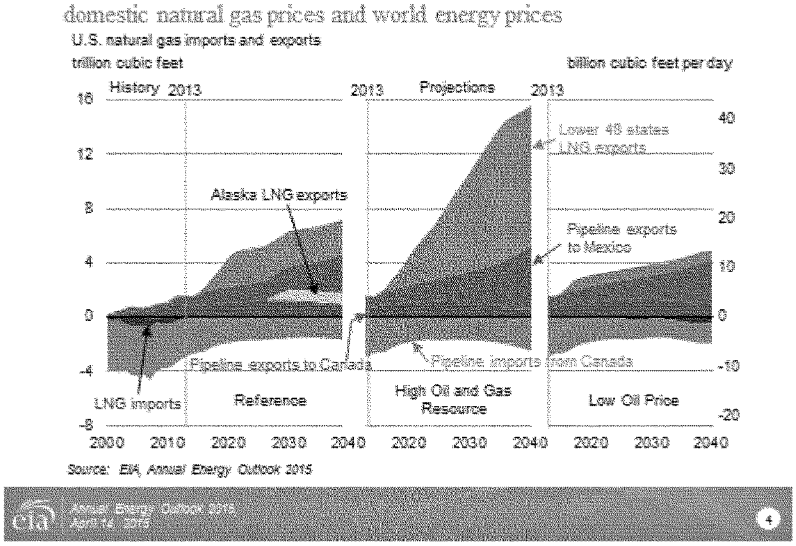


Figure 5. Growth of onshore crude oil production varies across supply regions, affecting pipeline and midstream infrastructure needs

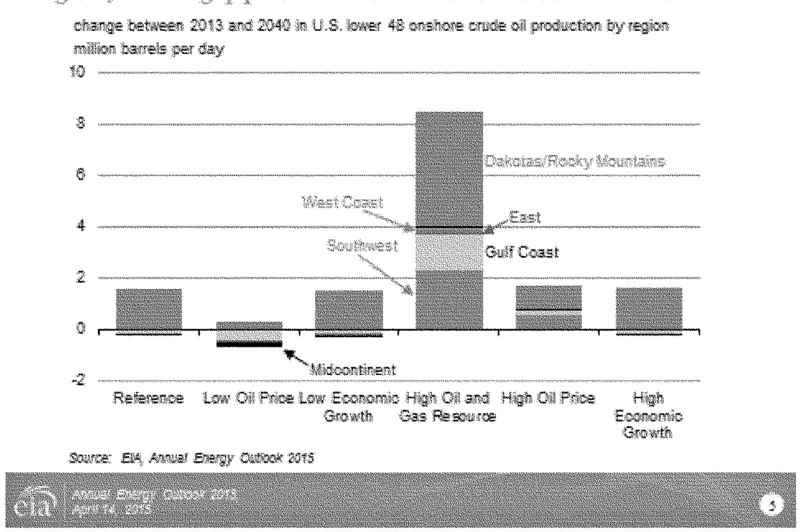



Figure 6. Growth in manufacturing output and use of natural gas reflect high natural gas supply and low prices, particularly in the near term

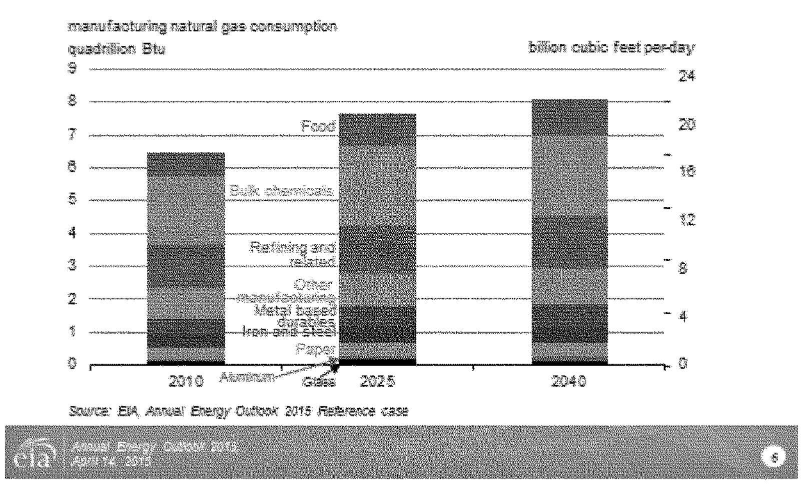


Figure 7. Electricity prices increase with rising fuel costs and expenditures for electric transmission and distribution infrastructure

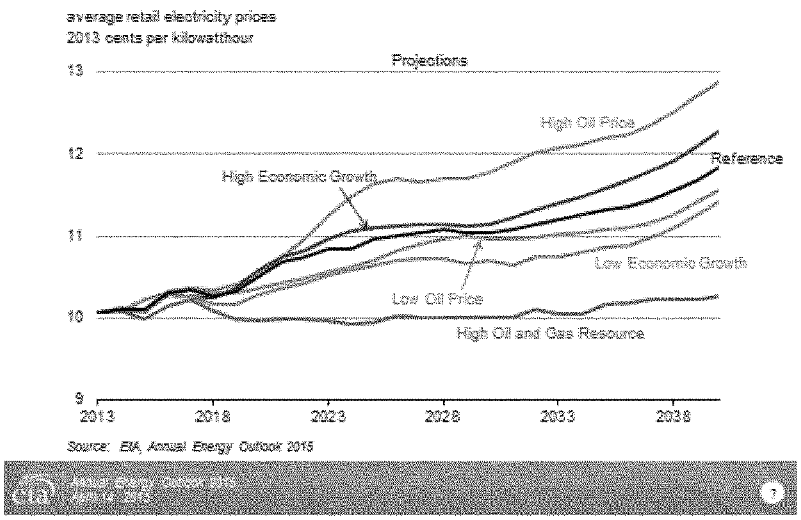
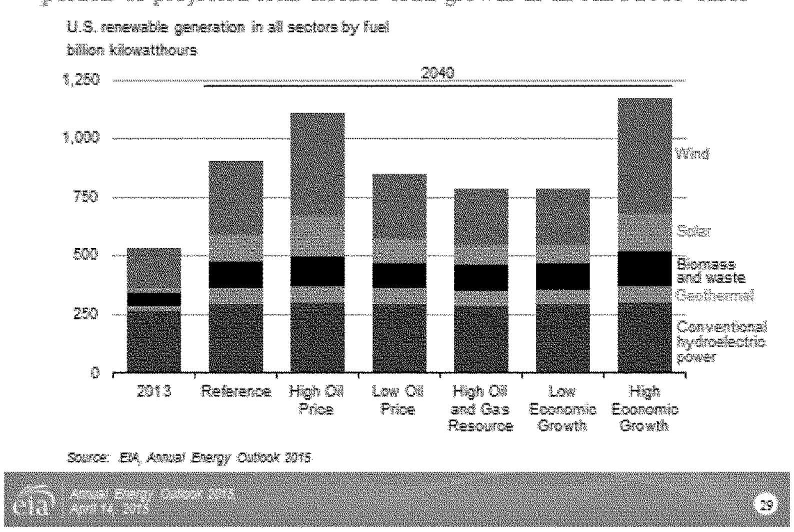



Figure 8. Growth in wind and solar generation meets a significant portion of projected total electric load growth in all AEO2015 cases



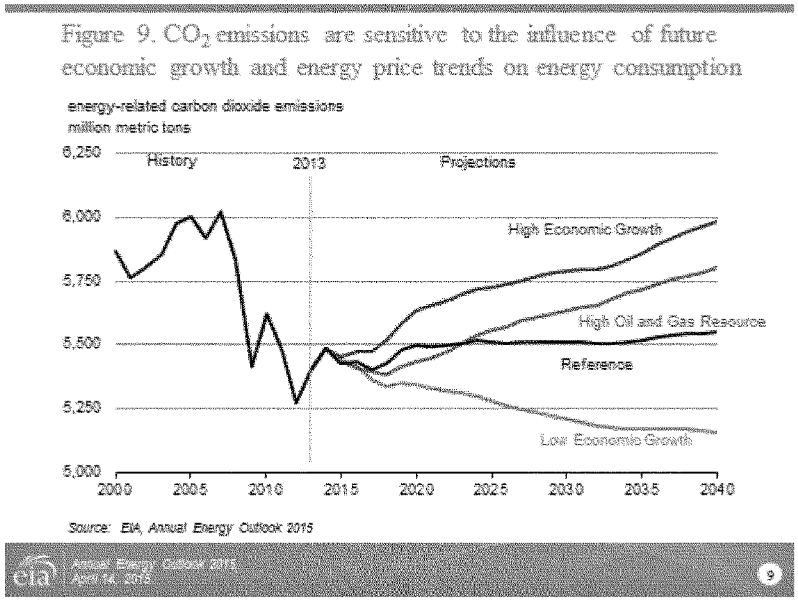


Figure 9. $CO_2$ emissions are sensitive to the influence of future economic growth and energy price trends on energy consumption
energy-related carbon dioxide emissions
million metric tons
6,250
6,000
5,750
5,500
5,250
5,000
History
2013
Projections
High Economic Growth
High Oil and Gas Resource
Reference
Low Economic Growth
2000
2005
2010
2015
2020
2025
2030
2035
2040
Source: EIA, Annual Energy Outlook 2015
eia
Annual Energy Outlook 2015
April 14, 2015
9

The CHAIRMAN. Thank you, Mr. Sieminski. I appreciate not only your recap here this morning, but again, the very serious and substantive work that EIA does.

I want to remind members we do, apparently, have a vote at 11:00. I am assuming it is just one vote, so we will move through our questions. We will keep going through that vote in case you have not had an opportunity to ask your question by the time the vote is called.

You started off your comments this morning by referencing the short term energy outlook and some of the information contained in that. There is a lot of focus here in the Senate on the situation with Iran and the negotiations that have been taking place, so I want to start my questions on the topic of the Iran situation.

In the short term report it is noted that Iran holds about 30,000,000 barrels of crude in storage and that they can ramp up in production by some 700,000 barrels a day by the end of 2016 in the event that sanctions are lifted. Obviously there is a great deal of discussion about when any sanctions might be lifted but one thing that we do know is that we understand that sanctions have cost Iran some $40 billion in oil revenues just last year alone.

A couple quick questions for you this morning, Mr. Sieminski.

If an agreement is reached that does lift those sanctions on Iran's exports would you expect that most of these new barrels to be exported would be to global markets?

Mr. SIEMINSKI. Thank you for the reminder.

Iran has, we believe, about 30,000,000 barrels of oil in storage. The removal of sanctions and how the sanctions are removed and whether it happens slowly over time or immediately is still undecided, as far as we can tell in the negotiations, would make a big difference.

Iran's production of crude oil, very recently, is around 2.8 million barrels a day, a couple million barrels a day of that is being used internally. So their exports are fairly low now. They will go up if the sanctions are removed.

How rapidly the oil in storage goes into the markets will depend a lot on how the markets behave themselves.

If they were to try to put all 30,000,000 barrels a day on the market very quickly it could lower the price and they would get lower revenue than they would expect.

If you assumed that they might try to move that over, let's say, a 100 day period the impact would be .3 million barrels a day.

We believe that Iran, over time, could increase its current production and exports by about .7 million barrels a day. So the total amount would be about a million barrels a day of production coming on to the market. It's really hard to see right now, Senator, how that could be absorbed without causing either other production to go down or the price to go down.

The CHAIRMAN. The direction of my question is if we are assuming that if sanctions are lifted and there is that opportunity for export, not just internally within the country but opportunity for export, that there will be additional revenue that is generated to Iran that they would otherwise not have had. Then our situation here in the United States is American companies are subjected to an export ban here. So you have got an incongruence going on here where we will have Iran able to make money off selling oil to our friends, our allies and using that new revenue for whatever purposes, perhaps nefarious purposes. We do not know.

At the same time, if we were to go to this snap back that everyone keeps talking about or re-impose sanctions, it would be helpful here in this country if we were willing to lead from the front on this and lift our own outdated restrictions on exports, helping other countries. This is more of a political statement than the analysis that you have given us.

I think it is important for us to recognize that if these sanctions are lifted and we, in fact, keep our own domestic sanctions in place, if you will, our ability to export a product that, again, could help our friends and allies and help our own country. It effectively ends up being a liability for us.

Mr. SIEMINSKI. I did bring with me a list of the studies that we've completed on the topic of crude oil exports in response to the letter that I received from you and Senator Cantwell. And one of those does deal with the issue of how gasoline prices are set in the U.S. markets. They generally tend to be tied to the global oil price rather than the West Texas Intermediate bench mark.

What that does suggest is that if more crude oil enters the global markets whether it's from U.S. exports or from Iran or from production anywhere, it would tend to lower the global oil price which would tend to lower gasoline prices in the U.S. So one of reports does suggest that allowing more exports of crude oil would either be neutral or lower the gasoline price.

There were a few studies that suggested that it could cause gasoline prices to go up. That seems to be a pretty low probability in our view.

The CHAIRMAN. We appreciate the work that you did on that report. Again, I thought that the overall conclusion there to be drawn that we would see an ultimate lowering in price, not only worldwide but here in this country, was very beneficial for the discussion and the debate going forward.

Senator Cantwell.

Senator CANTWELL. Thank you, Madam Chair.

Again, let me just reiterate how important I think good information is.

Mr. SIEMINSKI. Thank you.

Senator CANTWELL. Good information is, I think, like science. Usually like science you can get people to agree on that because it is basic information, so I hope we can do more.

I did want to make a point about what you just said about the renewables and the tax credit. It is almost like we have a perverse relationship, because we have permanency in the oil and gas tax credits and so they receive better treatment in the report. The renewables don't have as much predictability and certainty so they don't receive as good of treatment in the report. And then conversely the people look at the report and then make assumptions about policy. So it is really a perverse incentive that is demonstrated, because they do not have the same permanency and treatment.

I personally believe that you incent things that are nascent early technologies, and once things are well established that is when you stop the incentives. But we can continue that debate in the future. I want to ask you a couple questions.

One. What do you think the increase in the Dakotas and Rocky Mountain region in crude oil production could mean for those crude-by-rail numbers compared to the historic pattern that we've already been seeing? Are we going to see an even greater increase in crude-by-rail if the Rocky Mountain production increases?

Secondly, when can Senator Wyden and I likely see our regional data on energy price impacts of lifting the crude export ban?

Third, can you talk about why coal is going to become more expensive even under current law?

Oviously the biggest, if we move more quickly than your forecast shows on electricity with no-cost fuels like the renewables, could consumers see even lower overall electricity costs?

Mr. SIEMINSKI. Senator Cantwell, on a number of these things it would probably help if I try to give you the best view that I have now and get back to you for the record.

Senator CANTWELL. Yes.

Mr. SIEMINSKI. With some more detailed numbers.

Senator CANTWELL. I appreciate that.

[The information referred to follows:]

The Annual Energy Outlook 2015 Reference case projects an increase in crude oil production from the Dakotas/Rocky Mountains region; with growth from 1.7 million barrels per day (b/d) in 2014 to 2.5 million b/d in 2020 and 2.6 million b/d from 2021 through 2025, followed by a slow decline. Much of the increase is projected to come from the Bakken/Three Forks play in North Dakota and Montana, which increases from 1.1 million b/d in 2014 to 1.7 million b/d from 2020 through 2025 before slowly declining. If resources and/or oil prices are higher than assumed in the Reference case, projected production would be higher and production growth would persist for a longer period. Lower resources or prices would lower the projected production trajectory.

The Dakotas and Rockies production region includes parts of Petroleum Administration for Defense District (PADD) 2 (Dakotas and Midwest) and PADD 4 (Rockies). EIA's crude-by-rail (CBR) data, which are developed at the PADD level, show that rail shipments do not have a 1:1 to field production in those regions. Analysis CBR data from July 2012 through December 2014 indicates that the rate of growth of PADD 2 and PADD 4 field production far exceeds any increase in crude-by-rail movements from those regions to PADD 5 (West Coast). Future increases in rail shipments to West Coast refineries will depend on the economic viability of crude-by-rail versus imported crude oil, the type of crude oil refineries are able to process, and the regulatory outcomes for new or existing crude-by-rail facilities.

EIA will be releasing a report on transportation fuels in Petroleum Administration for Defense Districts 5 in July. The study covers the market with a detailed analysis of infrastructure from refineries to retail facilities.

In our October, 2014 report titled "What Drives U.S. Gasoline Prices", EIA concluded that gasoline prices throughout the United States are more related to changes in international crude prices than to changes in domestic crude prices. To the extent that changes to current crude export policies would increase global crude supplies, we would expect international crude prices to directionally decline, thereby lowering gasoline prices. On a regional basis, however, many other factors can influence gasoline prices, potentially negating any effect from enhanced crude exports.

The effect of a relaxation of current restrictions on crude exports on the actual level of such exports would depend to a significant extent on the level of U.S. crude oil production. Projected production is sensitive to both resource and technology assumptions and oil prices. In production scenarios where domestic production increases by enough to result in more crude oil exports than would occur under existing crude export policies, the most likely export pathway for crude from the Dakotas/Rockies region would be for increased pipeline capacity to move crude to the Gulf Coast, where it could be most easily exported.

Mr. SIEMINSKI. But let me try to go through that.

Thinking about production in the Bakken area and that's where most of the growth is occurring in the Rockies, some in the Niobrara which is also an oil area in Colorado in that part of the country. About a million barrels a day is coming out of the Bakken now. The upper end of the estimates that I've seen for the next few years are in the neighborhood of a million and a half, possibly as high as two million barrels a day.

So it's potentially possible that another half a million barrels a day, let's say, could be on the rails or in pipeline systems coming out of that region over the next few years.

Senator CANTWELL. I would just say no one is proposing these East/West pipelines. So while I appreciate where this debate has been about the Keystone pipeline, the issue is that we're talking about the demand. Our refineries are telling us it would have minuscule impact on the amount of crude that would move from the central part to the West Coast. So no one is proposing that pipeline.

Mr. SIEMINSKI. Right. In the crude-by-rail data that we have put out, most of the oil from that region is actually, the greatest portion of it, is moving toward the East Coast, some towards the Gulf Coast and a smaller amount towards the West Coast. How that would change over time would depend on a lot of things.

You also asked about regional price variations. I think that's something that probably I could come back to the record for you.

Mr. SIEMINSKI. There are——

Senator CANTWELL. When do——

Mr. SIEMINSKI. Regional variations in gasoline prices. They tend to be high on the West Coast and East Coast and lower in the Gulf Coast. A lot of that has to do with state and local rules on taxation and fuel, quality rules. And location of refineries makes a big difference and that sort of thing too.

On your question of why electricity prices go up.

There are going to be with relatively low growth, but the need for replacing existing plants as retirements occur for improvements in transmission and distribution. There's just not as much—there aren't as many people to spread the cost over, so the cost gets spread over roughly the same number of people and it causes rates to rise.

We also have increasing natural gas, oil over time and coal prices over time as well, kind of in line with inflation. So an 18 percent increase in electricity prices over a 25-year period is significant but it's, you know, less than one percent a year.

Senator CANTWELL. Could you get this information for Senator Wyden and me by the end of this year?

Mr. SIEMINSKI. I'm sure we could get something to you.

Senator CANTWELL. Okay. I have a feeling the export debate is going to continue, and I think every member of this Committee is going to be interested in what that would look like and the impact on U.S. pricing. So it won't be just Senator Wyden and me, but we certainly appreciate that commitment. Thank you.

Mr. SIEMINSKI. Thank you.

The CHAIRMAN. Senator Gardner.

Senator GARDNER. Thank you, Madam Chair, and I appreciate Mr. Sieminski for being here this morning.

A couple questions to follow up on what the Chairwoman had asked about the Iran sanctions. You say you don't have an idea on what impact it would have on price because you don't quite know how much would be released daily, monthly, what would be released and put on the market by Iran. Is that correct?

Mr. SIEMINSKI. We actually did say in the short term energy outlook that depending on the timing and how much could actually be moved into the markets that there could be as much as a $5 to $15 per barrel impact lower on oil prices from Iranian crude reentering the market.

And the basis of that, Senator, is just sort of looking at what happens when you add a million barrels a day, let's say, to the global oil markets, what kind of effect does that have, you know, relative to supply and demand balances. And typically we come up with numbers that for a million barrels a day would be something like $10 a barrel.

Senator GARDNER. Do you know what production impact that would have? Did you make a production impact projection on the U.S. then?

Mr. SIEMINSKI. We did not, but it would certainly be the case that lower oil prices would lead to, in the short run, lower production.

We have actually seen and EIA has published this in something we call the Drilling Productivity Report that three of the four big shale areas. So the four big areas are Eagle Ford and Permian Basin in Texas, the Niobrara, kind of in the midcontinent and the Bakken in North Dakota and Montana. Three of those areas, so the only area that's still, where oil production is still rising, is the Permian and those other three areas we believe oil production has flattened off.

And I would believe, Senator, that that's a reaction to the difference between $100 oil that we had, you know, a year ago and $60 oil that we had this year.

Senator GARDNER. Would it be possible to get a projected economic impact of Iranian oil exports as it relates to a decline in U.S. production?

Mr. SIEMINSKI. We could try to do some back of the envelope calculations for you.

Senator GARDNER. That would be great to see.

[The information referred to follows:]

The economic impacts of increasing Iranian exports will depend on whether and how much oil prices and production in other countries, including the United States, change in response. Generally, all things equal, when oil prices decline, the U.S. economy should benefit as the U.S. continues to be a net oil importer, with oil consuming activities making up a larger share of the overall economy than oil production activities. Certain regions in the U.S. where oil production is concentrated may experience reduced growth, especially if that region specializes in energy production and does not have a varied industrial base. Other factors will impact economic growth more than oil prices, such as what happens to exchange rates or whether consumers will spend or save the additional savings coming from lower energy prices. Many macroeconomic models estimate increases in U.S. GDP of between 0.1 and 0.5 percent for every 10% reduction in the oil price if exchange rates do not change. A strengthening exchange rate could affect the competitiveness of U.S. exports.

Senator GARDNER. Just a question as we talk about crude oil exports, as we talk about LNG exports. You and I have talked about this before. We would not be in a position to even have a conversation on exportation of LNG if it weren't for hydraulic fracturing. Is that correct?

Mr. SIEMINSKI. Well, we could be talking about LNG, Senator, but we'd be talking about LNG imports instead of exports.

Senator GARDNER. And it's the hydraulic fracturing, the capabilities, that have allowed us to enter into the export conversation on LNG.

Mr. SIEMINSKI. That's correct.

Senator GARDNER. Thank you, and we count rig counts. We have seen rigs being laid down in Colorado across the United States, but recent news reports have shown that we are actually increasing production in Colorado with several of our wind energy manufacturing centers. Wind turbine production is up.

Do we have a way of counting production at facilities like that in Colorado? I mean, we count rigs. Do we count turbines being produced in this country?

Mr. SIEMINSKI. I don't think that EIA actually has that on the state-by-state numbers for production of things like wind turbines, but we are looking at generation electricity on a state regional basis.

Senator GARDNER. Right.

Mr. SIEMINSKI. And in fact, one of the things that we'll be doing before the year is out here is reporting generation of electricity on an hourly basis. As far as I can tell when we begin this, this will be the first time that any statistical agency has collected data on anything on an hourly basis. So we'll be showing electricity generation hourly.

Senator GARDNER. Very good. In the Energy Outlook it talks about the capital costs of renewable technology decreasing over time resulting in more competition accounting for about 18 percent of total electricity generation in 2040. Do you believe at this point that we are accelerating renewable energy and efficiency technology into the grid at the scale we need to meet that energy production by 2040?

Mr. SIEMINSKI. I think on that I'd like to come back to you for the record so that we could get our electricity people to have a look at it.

These things get really complicated. I was thinking even about your earlier question about GDP with lower oil prices, you know, what effect does that have on the economy. And it actually, in the very near term, the lower oil prices tend to boost economic growth because there are more consumers of oil than there are of producers.

So in the United States we would expect GDP to go up a little bit, but it would obviously vary across states and states that are more dependent on production would tend to suffer.

And in trying to answer your question, I think I would, I'd like to be able to dig more into the numbers.

Senator GARDNER. Absolutely. Absolutely.

Mr. SIEMINSKI. And make sure we get the right numbers.

[The information referred to follows:]

In EIA's Annual Energy Outlook 2015, electricity demand grows slowly, less than 1 percent per year between now and 2040. The slowing growth in demand for electricity is in part due to improvement in energy efficiency in buildings and industry. During this period, renewable generated electricity grows by 2 percent and natural gas-fired generation grows by 1.3 percent. The projections include electric generating technologies that are commercially available or reasonably expected to be so over the time frame of EIA' s projections. EIA believes that the capacity expansion for renewable electricity generation resources and energy efficiency improvements projected in the AEO 2015 Reference case are achievable under current laws and policies.

Senator GARDNER. Thank you, Madam Chair.

Thank you.

The CHAIRMAN. Senator Franken.

Senator FRANKEN. I do have some questions I want to ask but can I give Senator Manchin my spot, then go next? Am I allowed to do that?

The CHAIRMAN. No.

Senator FRANKEN. I'm not?

The CHAIRMAN. You asked?

Senator FRANKEN. I asked and I'm not?

The CHAIRMAN. Well, we typically go back and forth from side to side.

Senator FRANKEN. No, no, no, no, no. I would not go next. I know that would be Senator Barrasso, but could I be next in order on this side? That is what I meant. I know the back and forth thing.

I yield to my good friend from the great State of West Virginia.

Senator MANCHIN. Thank you to my friend who has allowed me to have this opportunity real quick before we go to vote.

Mr. Sieminski, thank you so much for being here, and I appreciate it. We have had a chance to speak before, and sir, you know I have a real problem with what is going on. The demonizing of coal, it seems by a whole group of people who do not seem to understand the life that we all have is because of the domestic energy that we have right here in this country. We have developed to be one of the greatest industrial mites and built the middle class off of coal.

Now, with that being said, if there is another source of energy that will replace that we, in West Virginia, are fine. The bottom line is that we produce a lot of gas and a lot of coal and we do wind and we are trying to do everything. The thing that I am concerned about is no one has raised the alarm as far as the reliability of the system that we have right now and how we are dependent on that reliability, and that is basically base load fuels. And base load fuel is something that 24/7 will run.

It will produce whatever you want. You want to keep your refrigerator cool. You want your house cool. You want your factory to be working to where you have a job. You want all this to happen, but you have to have something that produces that energy and it has to be 24/7.

The only two base loads you have right now are coal and nuclear. Gas, I think, will become a base load fuel. It is not integrated enough yet because of the supply chain, correct? With the pipelines and things that we are——

Mr. SIEMINSKI. Well there certainly are places now where natural gas——

Senator MANCHIN. Has become——

Mr. SIEMINSKI. Is being used as base load.

Senator MANCHIN. Right.

Mr. SIEMINSKI. In our forecast we see more of that going out into the future, but you're absolutely right.

Senator MANCHIN. Let me just ask this question.

Mr. SIEMINSKI. I mean coal is more than a third, almost, right now, close to 40 percent of electricity.

Senator MANCHIN. And it anticipates being that until 2040. If there is a difference, if there is another fuel on the horizon, fine. But why in the world are we beating it to death and making it so impossible to produce the energy the country needs? The only thing I would ask you is this, sir. The aging of traditional electric base loads, the aging of these plants of coal and nuclear since they have been demonized and beaten the living crap out of. The age of them by 2040 will be the unit age of 60 years old. Those plants cannot expect to give the energy this country needs past 2040 at the reliability factor we have now.

What do we do? I have read your report. We have gone through your report. If we do not do any upgrading to the plants that are producing the energy right now, what do we do in 2041? Do you expect they will all be replaced in one year or do we just fall on our face as far as reliability? That is what scares me, and no one has raised that alarm.

Mr. SIEMINSKI. We have coal, nuclear and natural gas still accounting for a huge amount of our——

Senator MANCHIN. 75 percent.

Mr. SIEMINSKI. Yeah, exactly.

Senator MANCHIN. Yeah.

Mr. SIEMINSKI. And renewables do grow very rapidly, but they're, you know, a little below 20 percent.

Senator MANCHIN. Right. They're never going to carry the load, and we know that.

Mr. SIEMINSKI. Or the generation mix.

Senator MANCHIN. Right.

Mr. SIEMINSKI. Right.

Senator MANCHIN. I am just saying though you have particularly for 250 gigawatts of coal units remaining in 2040 with an average unit age of 65 years the expectation of operating of 75 percent of capacity. Your report says——

Mr. SIEMINSKI. Well, we don't have everything retiring in 2041.

Senator MANCHIN. Could you conduct?

Mr. SIEMINSKI. It would happen over time. We could show you. I'd be happy to provide for the record, Senator, how we see the retirement schedule. In our reference case, there are coal retirements, there are also nuclear retirements, and even some of the older natural gas plants retire. They do get replaced by better technology.

[The information referred to follows:]

The AEO2015 only extends to 2040, so projections for the post-2040 period, including coal plant retirements, are not available. Although EIA does not project beyond 2040, some inferences can be made about retirements in the early years after 2040 given our understanding of retirement decisions.

Coal plants do not retire upon reaching a certain age. Instead, a decision is made on the economics of the continued operation of the plant. In its modeling, EIA assumes $7 per kW annualized capital charge is incurred for coal plants that operate beyond 30 years of age. These added age-related costs account for major repairs or retrofits, decreases in plant performance, and/or increases in maintenance costs to mitigate the effects of aging. In our projections, coal plants are assumed to retire if the expected revenues from operating the plant are lower than the annual going-forward costs (including age-related costs, fuel, O&M costs and annual capital additions) and if the overall cost of producing electricity is lower by building and operating new replacement capacity.

In addition, the majority of the retirements that occur in the AEO2015 occur early in the projection period, and two major factors contribute to these retirements—low gas prices and the implementation of the Mercury Air Toxics Standards (MATS). Of the 40 gigawatts of projected coal plant retirements, 78% retire by 2016, the year that EIA models MATS implementation. The last projected coal retirement takes place in 2025, well ahead of the last AEO projection year of 2040.

Both market and policy factors do affect projected retirements of coal-fired plants. For example projected coal-pant retirements are higher in EIA' s High Oil and Gas Resource case, which assumes more resources and better technology that results in significantly lower projections of natural gas prices than the Reference case, which increasing the incentive to increase gas generation and reduce coal generation. Policy also matters, as exemplified in EIA's recent analysis of the Environmental Protection Agency's proposed clean Power Plan rule; compliance with that rule, as modeled in EIA's analysis, caused projected coal-fired generation to decrease substantially and coal plant retirements to increase substantially.

Presuming current laws and regulations, rising gas prices, and rising electricity demand while continuing to include age-related costs, and no other explicit technical limitations on expected plant life, a sudden onset of coal plant retirements in the early 2040s would seem unlikely. Because of the inherent uncertainty in aging related costs, EIA periodically reviews its methodology and gathers industry expertise and advice on the subject of aging. EIA held a workshop on the subject following its 2015 Energy Conference.

Senator MANCHIN. Here is the other thing. To properly reflect the energy security benefits of combined CTL, basically with EOR, enhanced oil recovery, it seems to me it would make good strategic sense for us as a country to where we have these oil productions now. If you go to coal to liquids and use the EOR so we have no emissions. It is going down to produce more oil that gives us the reliability.

We do not see anybody planning out for this. Everybody thinks in this perfect world that we're going to be able to extract out of the air or the water, the energy that we need. I hope that day would come, but I like to prepare in case it doesn't come and the demands we have we are able to meet. That is all I am trying to find is the balance, sir. You all have been pretty balanced and realistic. What do you recommend and how should we proceed from here?

Mr. SIEMINSKI. Well, as I said at the beginning of my remarks, we try to stay out of the business of making recommendations. We leave that to the policy makers.

Senator MANCHIN. But has anybody questioned in your——

Mr. SIEMINSKI. I'd be happy to pass your concerns along to the Office of Fossil Energy at DOE and they could probably help answer.

Senator MANCHIN. But you have heard us all. We all trust, and basically we know, that you have people who are doing pretty accurate forecasts.

Mr. SIEMINSKI. Right. Right.

Senator MANCHIN. These forecasts have not been that far off in the past, yet no one seems to be heeding your forecast warnings of what we are going to be facing as a country. That is what scares me. I do not know how to get that to a level. It is just like you are saying, well, you come from West Virginia. We expect you to rattle the cages.

If someone told us in West Virginia you could have commercial hydrogen by 2040.

Mr. SIEMINSKI. Right.

Senator MANCHIN. And you do not need any fossil whatsoever. We will find a way to make it, trust me. We always have in West Virginia.

But you are going to be needing the products that we produce. We want to make sure that we are able to do the job you need for our country, and we need somebody to help rattle the cages with us.

Mr. SIEMINSKI. Well, we do try to provide the information, and we try to let the policy makers come up with the solutions. [Laughter.]

Senator MANCHIN. What you are saying is I need more help, right? [Laughter.]

Mr. SIEMINSKI. Well, we'll do as much as we can with——

Senator MANCHIN. Your job and you are doing a good job and I appreciate it, sir.

Senator FRANKEN. Madam Chair, may I say I regret allowing the Senator from West Virginia go before me? [Laughter.]

The CHAIRMAN. You cannot pull back that, Senator Franken.

Senator Manchin, the monkey is still on our back here to make sure that we do this.

Let's go to Senator Daines since Senator Barrasso has stepped out, and then we will turn to Senator Franken.

Senator DAINES. Thank you, and Senator Manchin, I am grateful for you, just so you know—you betcha.

Mr. Sieminski, your assessment talks about strong growth in domestic crude oil production from the tight formations. I assume that includes the Bakken formation in Montana as well as North Dakota?

Mr. SIEMINSKI. Yes, Senator, yes.

Senator DAINES. As you know when you cross the state line going west from North Dakota into Montana we have a lot more federal land in Montana than our neighbors in North Dakota. How much of the projected growth in production do you believe will come from Federal lands versus state or private lands?

Mr. SIEMINSKI. I'd be happy to try to supply some of that for the record for you. We do a report. We published one that shows the location of oil production by private, Federal and American Indian lands. The bulk of the resources and we have overlaid the shale basins that we know of with a map of who the landowners are, tends to show that the bulk of the shale resources are on private lands. That is obviously going to vary from state to state, and perhaps we could get you some information on that.

Senator DAINES. You would not want to venture a prediction on that at all or just wait to get the information from you?

Mr. SIEMINSKI. I would rather have the numbers.

Senator DAINES. Yeah.

Mr. SIEMINSKI. Than to make a guess.

Senator DAINES. I think——

Mr. SIEMINSKI. I do know that the production on private land is way above the level of production on Federal land.

Senator DAINES. I think over the last six years or so the production on private and state land is up around 50 or 60 percent. I think we are actually down single digits on Federal lands over the last six years, but I would be interested to get your——

Mr. SIEMINSKI. Yeah.

Senator DAINES. Go forward.

Mr. SIEMINSKI. And we will provide you with those numbers, Senator.

[The information referred to follows:]

Roughly 35% of the nearly 2.0 million barrel per day projected growth in domestic crude oil production between 2014 and 2020 is estimated to come from federal lands, defined to include both onshore and offshore areas. The federal Gulf of Mexico accounts for 95% of the growth in production from federal lands during this period, as new deep water projects start up.

Historical oil production information is available from the ETA study "Sales of Fossil Fuels Produced from Federal and Indian Lands, FY 2003 through FY 2013" at *http://www.eia.gov/analysis/requests/federallands/pdf/table7.pdf.*

Senator DAINES. Another question. Was the Department of Interior's recently announced rule on hydraulic fracturing for Federal lands factored into your projected growth numbers?

Mr. SIEMINSKI. Not specifically. There are different views about what that possible impact would be. The industry itself is moving towards greener completions across the board. So on both private and Federal lands it does tend to lift costs a little bit, but there are offsetting factors too.

It's one of the issues and greenhouse gas emissions. Perhaps we could come back to you on that with more information too.

[The information referred to follows:]

The BLM hydraulic fracturing rule was released in March 2015, after the Annual Energy Outlook 2015 analysis was completed. The rule is not expected to have a major impact on drilling because (1) the rule only applies to drilling on federal and American Indian lands and tight/shale formations that are primarily situated on nonfederal lands; (2) many provisions in the rule are similar to or based on current practices and State requirements; and (3) BLM estimates the incremental cost will be less than 0.25% of the cost to drill the wells (e.g. less than $12,500 on a $5 million well).

Senator DAINES. Yes, we were disappointed in Montana. We have very robust and rigorous regulations.

Mr. SIEMINSKI. Right.

Senator DAINES. Because we have got to live near where the activity is occurring. We want to make sure we protect our environment and just do while this additional layer of regulations. We did not see that as helpful, certainly in Montana, when we think we have got that well regulated ourselves. Your assessment talks about an 18 percent increase in the average retail price of electricity over the projection period. What were the factors contributing to the projected increase in electricity rates in your assessment?

Mr. SIEMINSKI. Senator, let me just take a quick look at what some of those numbers were.

Senator DAINES. As you are looking that is important, certainly, for many, many states and for all of us. I think we are about 40 percent of things like——

Mr. SIEMINSKI. Right.

So what we said was——

Senator DAINES. Coal.

Mr. SIEMINSKI. You have rising costs for electric power generation, transmission and distribution coupled with the slow growth of electricity demand or what add up into that 18 percent number.

So within the generation area some of that is going to be fuel increases and some of that will be the capital costs of expansion.

Senator DAINES. I do not think your assessments, though, take into account the EPA's clean power plan.

Mr. SIEMINSKI. That's correct.

Senator DAINES. I can tell you Montanans are very concerned given that 51 percent of our electricity comes from coal that this plan would further increase electricity rates for Montanans, for Montana families, while also damaging our state's ability and our tribe's ability to produce coal.

I did a field hearing on the Crow Reservation last week. Their unemployment rate is 47 percent today. If they lost those coal jobs it raises to over 80 percent unemployment rate. Certainly it is a concern back home. It is killing jobs, affecting our tax revenues which fund our schools, our teachers, our infrastructure and supporting overall essential services.

Given these factors to electricity rates I remain highly concerned about the EPA's proposed actions which would severely impact Montana's coal sector. We have the most recoverable coal deposits in the United States.

I am out of time, thank you.

Mr. SIEMINSKI. Thank you, Senator.

The CHAIRMAN. Thank you, Senator Daines.

Senator Franken.

Senator FRANKEN. Thank you.

I am actually concerned also about climate change, so that is why I regretted yielding to the Senator from West Virginia. [Laughter.]

And coal and we had all this coal talk. Okay. [Laughter.]

You state very clearly in your report that energy market projections are subject to a lot of uncertainty, and one reason for this uncertainty is that you cannot predict technological breakthroughs, for example. No one could have predicted the magnitude of the shale revolution when hydro fracking was in its infancy. Now because of decades of major Federal investments, the commercialization of this technology has made the United States an energy super power. Similarly advanced energy storage will be a game changer for the utilities industry. It will allow us to incorporate more renewables so we can utilize wind and solar power when needed, if you can store wind that blows at night then that is the game changer.

So instead of very modest growth in renewables which you project in this report, advanced energy storage could allow renewables to play a much more prominent role in our electricity generation mix.

Can you talk about the next big breakthrough in grid scale storage and how it would impact the amount of electricity that would be generated from renewable sources?

Mr. SIEMINSKI. I'm sure we could supply you with some data for the record.

[The information referred to follows:]

Availability of grid-scale electricity storage could impact the amount of renewable resources that could be accommodated on the grid. Wind and solar resources produce variable, intermittent generation that may or may not match patterns of local or regional electricity demand on a daily or seasonal basis. Incorporating electricity storage with renewable generation could enable better operator control of these resources by storing excess generation and redeploying it during peak-demand periods. While the presence of energy storage may help the grid accommodate higher levels of wind or solar generation, EIA does not believe that renewable generation levels projected in the AEO2015 or its side cases would require the addition of storage to be realized.

Currently EIA collects data from a number of utility-scale storage facilities located within the U.S. These technologies include pumped-hydroelectric generation, compressed air energy storage, flywheel, and a variety of battery technologies. EIA does not specifically model new storage technologies in the Annual Energy Outlook and does not predict which technology might be the next breakthrough technology.

Mr. SIEMINSKI. In general, battery technology simply makes things like wind which tends to be stronger at night and solar which, obviously, is during the daytime, usable across the 24 hours of demand.

There are some interesting things. Just recently I've been reading about aluminum as a battery material rather than lithium. It's cheaper. It would have more cycles associated with recharging. It could be a huge development.

That kind of thing doesn't really have—doesn't work its way, as you said, Senator, into EIA's forecast because——

Senator FRANKEN. Sure.

Mr. SIEMINSKI. We're not. We try to forecast the future, but we don't have our own crystal ball in that sense.

We do have workshops at EIA and conferences all the time and one of those conferences coming up is actually going to deal with questions like yours. I'd be happy to make sure that your staff is invited to that. We'd be delighted to have you come, if you'd like to.

Senator FRANKEN. When is it?

Mr. SIEMINSKI. Um.

Senator FRANKEN. Well, you can get that information to us.

Mr. SIEMINSKI. Yeah, well——

Senator FRANKEN. I would love to——

Mr. SIEMINSKI. Love to do that.

I think it is important. I mean we have looked from time to time at the technology, even on the generation side. I think we are doing pretty well with our wind numbers.

A lot of the issues associated with whether or not we're capturing, the number is properly, along the lines of Senator Cantwell's questions, are in the solar area where the costs have been coming down. The technology is improving. And whether we're fully capturing that or not, you know, I grant you, it's an open question.

Senator FRANKEN. Okay. I want to turn to LNG exports. The different scenarios considered in the Annual Energy Outlook highlight the risk that large volumes of LNG exports can drive up domestic natural gas prices. For example, in one of the scenarios where LNG exports exceed eight trillion cubic feet per year you project a 35 percent increase in domestic natural gas prices. The EIA found similar price increases in its previous studies which looked specifically at how increased levels of LNG exports would impact American consumers and industries.

That is very serious to a state like Minnesota which produces no natural gas, but uses a lot of electricity for its manufacturing and uses a lot of, also, natural gas in its manufacturing.

What impact would these kind of price increases have on the manufacturing sector, particularly for natural gas intensive industries such as the paper pulp and primary metal manufacturing sectors?

Mr. SIEMINSKI. The EIA actually did a report at the request of the Office of Fossil Energy at the Department of Energy on the impact of increased LNG exports to the U.S. energy markets. First we were asked to look at possible export rates as high as 20 billion cubic feet a day.

Across all of the cases in the current Annual Energy Outlook the highest we get is 13 or 14 billion cubic feet a day. I would kind of look at that 20 billion cubic feet a day request as a stress test, sort of like, what happens if oil goes to $250. We don't really expect it to. What if LNG exports were to go 20 billion cubic feet a day? What would it do?

Across all of those estimates we had end use consumer bills in residential, commercial and industrial sector going up anywhere between one to eight percent. I would think that in thinking about this it probably would be towards the lower end. We do find that prices would go up.

A couple of other things, Senator, that I think actually would be important.

One is that we, although natural gas prices would go up and it could have a differential impact as you said between those states that are producing gas and those that are doing more consumption. But a state like Minnesota actually has a fairly decent industrial base in things like heavy construction and services that would be useful in the producing industry. So there would be opportunities for the State of Minnesota to sell to those people who are making more money.

One of the other things that I think would be important is that if we are right about how gasoline prices are set in the U.S. markets. That is based on the global oil price. Putting more U.S. natural gas into the global markets would probably tend to lower the prices for all fuels, including oil, which would then be reflected in lower gasoline prices in the U.S. and Minnesota, obviously, is a consumer of gasoline as are all the other states.

So there are offsets, and I think some of the times I know about the EIA models. Look, we try really hard to get it right, but we can't possibly get a lot of these secondary and complicated effects in there. And some of them that would go the other way and would actually help, I think, rather that hurt a state like Minnesota.

Senator FRANKEN. Alright. Well, thank you for your answer.

We are way over my time, but I want to continue this conversation.

Mr. SIEMINSKI. Thank you, sir.

Senator FRANKEN. Thank you, Madam Chair.

Mr. SIEMINSKI. It's very serious because——

Senator FRANKEN. It is.

Mr. SIEMINSKI. And it should be addressed. We're trying the best we can.

Senator FRANKEN. Thank you.

Mr. SIEMINSKI. Thank you.

The CHAIRMAN. Well, it is serious. It will be continued in this Committee and in others because as we look at those policies that may, in fact, inadvertedly be keeping our prices higher than we might like. We need to look to how we might refresh those policies.

Senator Barrasso.

Senator BARRASSO. Thank you very much, Madam Chairman.

I want to continue on this line of questioning because in February of this year President Obama's Council on Economic Advisors issued its report. It said, "An increase in U.S. exports of natural gas would have a number of mostly beneficial effects on natural gas producers, unemployment, on U.S. geopolitical security and the environment."

The President's advisors explain that natural gas exports of six billion cubic feet per day could support as many as 65,000 jobs. They go on to say that expanded natural gas exports will create new jobs in a range of sectors including natural gas extraction, infrastructure investment and transportation. So the President's economic advisors also go on to say that the natural gas exports for the United States would have, "a positive geopolitical impact."

Specifically they explain that U.S. natural gas supply builds liquidity in the global gas market, reduces European dependence on the current primary suppliers of Russia and Iran. So I am encouraged that your agency, the EIA, predicts that the U.S. will be a net exporter of natural gas by 2017. Would you expand on additional benefits that you see the natural gas exports bring to the United States, if you see additional ones?

Mr. SIEMINSKI. Senator, I think it's actually hard to expand on the list that you just went through. I didn't hear anything in there that I would disagree with.

One of the things, if Senator Franken were here, the NERA study did find that there might be some impacts on wages from higher natural gas prices. And from what I can tell in the models, many of the models don't deal very well with questions like that. And the effects seem to be pretty small so that I think that the overall direction that virtually everybody who has looked at this comes to is that trade, generally speaking, has positive benefits across the economy. And LNG trade is no different.

Senator BARRASSO. Great. I also wanted to follow up on Senator Gardner's questions about Iran. Last month the Wall Street Journal ran a front page article that I have here. "Iran Nuclear Deal Portends Rush of Oil, New Price Drop."

The article explains that independent observers believe that lifting sanctions on Iran could result in boosting Iran's exports by 800,000 barrels per day within the year. Meanwhile the Wall Street Journal yesterday, that was a month ago, ran a story yesterday, and this is on page B1. "Oil industry layoffs hit a 100,000 and counting in the United States."

Would you discuss the impact that lifting sanctions on Iran would have on American workers in the oil and gas industry?

Mr. SIEMINSKI. We, EIA, actually published in our short term energy outlook our assessment. And we talked a little bit about that earlier. But refreshing, there's 30 million barrels of oil that Iran has in storage that could come out at any time. And how quickly that comes out is hard to decipher.

We believe that the Wall Street Journal article that you mentioned said 800,000 barrels a day of growth in production. We think the number is 600,000 to 700,000 barrels a day, could be 800,000 barrels a day, let's say, by the end of 2016.

Senator BARRASSO. Yes, the Economist this past week said 800,000.

Mr. SIEMINSKI. Right.

Senator BARRASSO. Well, but roughly, yes.

Mr. SIEMINSKI. So, again, our roughest estimate is that this could lower the price. If everything else held constant, that much more oil on the market would lower the price anywhere between $5 to $15 a barrel. That lower price implies lower drilling activity which would then influence the numbers that you were citing.

How quickly all that comes to pass? Whether something else might happen in the global markets?

Just as an example, Senator, we are seeing a little bit of a lift in demand over the past few months. EIA has increased its estimate of gasoline demand on the back of better income and lower gasoline prices, along with interestingly, employment, that as the employment numbers have recovered we're beginning to see people drive more which leads to gasoline. And trying to get all those numbers to balance is tricky.

Senator BARRASSO. I had a final question on the predictions that EIA makes on the average retail price of electricity. It predicted it will increase as much as, I think, 28 percent by the year 2040.

Mr. SIEMINSKI. Right.

Senator BARRASSO. It explains that its predictions now do not take into account the EPA's forthcoming Greenhouse Gas Regulations for the existing power plants. In other words any increases in electricity prices resulting from these greenhouse gas rules will be in addition to the increases that you currently predict, the 28 percent.

So I understand that EIA plans to issue a separate report on the impact of the EPA's greenhouse gas rule. Can you tell me when you expect to see that report?

Mr. SIEMINSKI. Yes, Senator.

I think the reference case number was 18 percent out to 2040 for retail electricity prices. A lot of that coming from higher generation costs because of fuel and largely because of our assumptions of rising natural gas prices.

Specifically to your question of will we look at the Clean Power Plan impact? Yes, we will, and I hope to have that report out in May.

Senator BARRASSO. Because I know that in the past EIA has sometimes underestimated electricity prices in the reports. I am just curious if any specific steps are being taken now to ensure that there isn't an underestimation of the impact of the EPA's rules on retail electricity rates.

Mr. SIEMINSKI. Well, we're looking very closely at that, and I would be happy to come up and discuss it with you when we have the report.

Senator BARRASSO. Thanks, I appreciate it.

Mr. SIEMINSKI. Thank you, Senator.

Senator BARRASSO. Thank you, Madam Chairman.

The CHAIRMAN. Thank you, Senator Barrasso.

Senator Hirono.

Senator HIRONO. Thank you, Madam Chair.

Aloha, Mr. Sieminski. In 2008 Hawaii set a 40 percent renewable energy goal and a 30 percent increase in energy efficiency both by 2030, and this is the most ambitious goal in the country. Why? Because Hawaii residents were paying, still do, pay the highest electricity rates in the country. We needed to get away from our over reliance on imported oil for 90 percent of our energy, so Hawaii now produces 18 percent of its electricity from renewable sources and achieved a 16 percent improvement in energy efficiency.

I see that EIA projects that nationwide the U.S. will only achieve 18 percent renewable energy by 2040 if we continue our current policies. Do you agree that the U.S. could develop much greater use of renewable energy if we establish national standards for renewable energy and energy efficiency like Hawaii has done? Because when we set these national standards it does spur the private sector to engage in research and development into alternatives in renewables, we think. Do you agree with that? And if we did that, couldn't we achieve renewable goals greater than what you are projecting by 2040?

Mr. SIEMINSKI. Senator, my opinion on whether we should do that or not is—I like to think of myself as one policy remark away from returning to the private sector. [Laughter.]

Senator HIRONO. Oh, take a chance. [Laughter.]

Mr. SIEMINSKI. On the issue, you know, if we had state renewable standards. In fact, state renewable standards and the Federal tax credits are a very important part of what's driving renewables in our models, the technology and the role that cost reductions driven by technology would also be very important. Yes, it's certainly possible that the numbers that we're showing could be higher, and they definitely are, even under our no sunset case.

John Conti and Paul Holtberg, who are here with me today, they are the ones generating a lot of this material. I could ask them, you know, have we in the past done a high technology case to look at things like this? I think we have and we'll be doing more of that in next year's Annual Energy Outlook. We'll have a broader set of cases. And so perhaps next year I could come back and report on those outcomes.

Senator HIRONO. Yes, I think there definitely is a connection between setting certain standards and the spurring of developments that would help us meet those standards.

In looking at your figure eight, you show the growth of wind and solar. So that makes energy storage, I would say, a priority for us. According to a recent analysis by the Rocky Mountain Institute, a system of solar panels and battery storage that is connected to the electric grid would be the most affordable option for places like Honolulu, Hawaii in 2016 and many other states in the next decade.

A March 2014 analyst at Morgan Stanley concluded prices for energy storage could drop by more than half in the near future, and they expect batteries, including them, to be cost competitive with the grid in many states and think investors generally do not appreciate the potential size of the market, meaning the storage market.

Does EIA acknowledge or appreciate the potential size of the battery storage market? And has the EIA include a recent assessments of storage costs in its projections of renewable energy deployment in the Annual Energy Outlook?

Mr. SIEMINSKI. Our electricity group does look at things like that, very carefully, and cost is still an issue. I do understand the position that states like Hawaii and some of our territories, Puerto Rico and the U.S. Virgin Islands are largely dependent on oil for generation of electricity, and it does put them in a very tough position.

I guess the good news, Senator, is that oil prices are half the cost of this year of where they were last year which should make electricity lower in Hawaii. And it would be interesting to see those numbers as they come out. Can we move to these other fuels?

One of the things you didn't mention that I know is being looked at by people in Hawaii is whether or not liquefied natural gas.

Senator HIRONO. Yes.

Mr. SIEMINSKI. Possibly coming from Alaska could help to generate power in Hawaii at prices competitive with some of the other fuels and lower than what you're currently paying.

Senator HIRONO. Madam Chair, if you don't mind?

Clearly when we rely on oil then we do have climate change issues. So states like Hawaii will make a commitment to get away from oil reliance and into the renewables and alternatives. I would say that the developments R and D are making on storage are a really important part of our energy future.

Thank you, Madam Chair.

Mr. SIEMINSKI. I absolutely agree with you, Senator, and we could look at a range of how electricity prices could change or how renewables could move into the mainstream faster with improvements and things like battery technology and some of the transmission. And as I said, I think in the next year's Annual Energy Outlook we'll have more of that. Thank you.

The CHAIRMAN. Senator King.

I also want to acknowledge that, in reference to your comment, Mr. Sieminski, we would love to be supplying our friends to the South in Hawaii with some of our natural gas. [Laughter.]

The CHAIRMAN. We have got to get there first.

Senator King.

Senator KING. Thank you, Madam Chair.

First, I want to thank you for the work that you do. I consult the data from your agency probably two or three times a week and now that I am on this Committee it will probably be even more frequent.

Mr. SIEMINSKI. Thank you, Senator.

Senator KING. This is 50 shades of grey for a data geek. [Laughter.]

I just really appreciate the work you do, and I also appreciate your resistance to being dragged into the policy discussions because the data is so important.

In my experience having good data is what drives good policy, and if people can share an understanding of the data they can generally get to the policy conclusions without that much difficulty.

This has been a fascinating hearing because of the regional differences. I would ask Senator Barrasso to come to Maine and tell the people of Maine the virtues of higher oil prices. How $1.00 diminution in gasoline and heating oil prices is $1 million into the pockets of the people of Maine.

I just did the calculation, and that comes to $770 for every man, woman and child in the state.

Mr. SIEMINSKI. Right.

Senator KING. So lower oil prices. I noticed he used the phrases would cost jobs in the oil and gas industry, but the larger question, of course, is what would be the benefit to the economy at large?

We are seeing a rejuvenation of manufacturing in this country, for example, because of the low prices of energy which is a competitive advantage we now have with other parts of the world, particularly in natural gas. So a fascinating discussion all about your point of view, I think.

The other piece, of course, was the Senator from Montana talking about electricity prices and coal. New England prices are about 35 percent above places that are dependent on coal. The problem is we do not get the cheap power, but we do get the pollution.

We did a study some years ago in Maine that if we shut down every factory in Maine, took every car off the road, we would still have ozone violations along our coast because of pollution being transported by the westerly winds, so it is a very interesting regional discussion here.

I just have a quick couple of questions. I apologize for the speech.

In a nutshell, what will the effect of opening up oil exports be on domestic oil prices? My assumption is it will not be much because we have got a worldwide oil price anyway. But is that what your data shows?

Mr. SIEMINSKI. Yes, sir. At least looking at history what our study showed was that because gasoline prices in the U.S., heating oil prices as well, tend to be tied to the global markets. And the reason for that is we're both big exporters and importers of oil products like gasoline, diesel fuel, jet fuel and so on. The net effect that we saw was a slight decrease in the price of petroleum products if the U.S. were to export crude oil.

Senator KING. And that would include decrease of those products in the U.S.?

Mr. SIEMINSKI. In the U.S.

Senator KING. Okay. By the way, on the question of Iran that 30,000,000 barrels that is stored in the ships, they think.

Mr. SIEMINSKI. Yes, sir.

Senator KING. What is the daily worldwide consumption of oil?

Mr. SIEMINSKI. Worldwide consumption is about 92,000,000–93,000,000 barrels a day.

Senator KING. So we are talking about an eight hour supply on ships.

Mr. SIEMINSKI. Worldwide.

Senator KING. I just think we need to put that in perspective.

Mr. SIEMINSKI. What you wouldn't want is to see it all come in at the same time.

Senator KING. Clearly, I understand that, but it is not like it is a month's supply. It is a third of a day's supply.

Mr. SIEMINSKI. Correct, and Iran would have its own financial incentives to try to minimize the impact on the global market.

Senator KING. When you did your estimates about the penetration of renewables, did you make any assumptions about technology advancements in storage or energy storage capacity because as you've testified that would make a big difference in the ability to integrate wind and solar into the grid, for example.

Mr. SIEMINSKI. We do make assumptions about improvements in technology across all of the fuels, and I think where the arguments come, Senator, is on the pace of those changes in technology.

Senator KING. And the only thing we can say for sure about any of our predictions is that they will be wrong. [Laughter.]

Mr. SIEMINSKI. I know that we're going to be wrong. I'd like to not be wrong right away. [Laughter.]

Senator KING. I would subscribe to that as well. I would like to be proven wrong long after I am gone. [Laughter.]

But how about any assumptions about $CO_2$ sequestration in your calculations because that could make a huge—Senator Manchin is right. We have a huge coal asset. If we could figure out how to deal with the $CO_2$, that would be that would be a plus for everybody.

Mr. SIEMINSKI. There actually is one of the things—and Senator Manchin didn't mention it directly, but he alluded to the Kemper Facility that's being built by, I think, the Southern Company that will take coal and turn it into natural gas and hydrogen, capture a good portion, I think more than half of the carbon dioxide. And move that by pipeline to an old oil field that would benefit from having $CO_2$ injection to help increase the oil production. What we found. I mean, this is a very early stages, really nobody has tried to do this at this scale before, is that it's been costly. I think that if we're going to do this economically at scale where you have more of these, we're going to have to find ways to improve the cost of doing it.

Senator KING. One of the realities here is that none of us can really predict where the technology will go. Hydro fracking, I think Senator Franken mentioned, was developed under Federal research and development support. Nobody predicted that even eight or nine years ago in terms of the impact that it was going to have, and there may be some kid somewhere who is figuring out how to sequester coal $CO_2$. And it is going to change the whole world.

Mr. SIEMINSKI. It would really help actually. And finding ways to do that, the Department of Energy, other part, obviously not EIA, but there are parts of the Department of Energy, Fossil Energy and the labs who are working very hard on trying to find ways to make that happen.

Senator KING. I am over time. Thank you very much. I look forward to continuing the discussion.

I think another issue is distributed energy. Distributive solar on the roof is going to have broad effects, but I will leave that for another time.

Mr. SIEMINSKI. Senator, with your permission, 30 seconds on that. We're really interested in that issue at EIA. It's very hard for us, actually to do because it's behind the meter. It's hard for us to do that. We tried it on an annual basis.

We have looked at rooftop solar and its impact, residential and commercial. It's easier to get the commercial numbers than residential.

We are looking for ways now, and I think we'll be successful at this. This year I think we're going to start to find ways to make estimates on a monthly basis of what the impact is of rooftop solar on the electricity generation markets, and it's one of those other areas that we've been trying to emphasize as an important part of the ongoing effort at EIA to stay up with current technology.

Senator KING. It could very shortly turn into a true disruptive technology.

Mr. SIEMINSKI. It could very well do that. I mean we do know that the combination of tax incentives and the environmental positive nature that many people who were installing it want to see is pushing this, so the growth in that area——

Senator KING. It could dramatically lower costs——

Mr. SIEMINSKI. Right. Correct.

Senator KING. Thank you. Thank you, Madam Chair.

Mr. SIEMINSKI. Thank you, Senator.

The CHAIRMAN. Thank you, Senator King.

Senator Hoeven.

Senator HOEVEN. Thank you, Madam Chairman. Thanks for holding this hearing today. Mr. Sieminski, thanks for being here.

Mr. SIEMINSKI. Thank you, Senator.

Senator HOEVEN. And for your very, very important work. I would mention, pursuant to one of the last questions brought up by the good Senator from Maine, in North Dakota the Dakota Gasification Company takes lignite coal and converts it to synthetic natural gas. That natural gas is put in the pipeline and sent off to a number of different states for use.

We also capture the $CO_2$, condense it, cool it, condense it, put it in a pipeline and ship it to what is called the Weyburn oil fields which are actually in Canada just over the border from North Dakota. That $CO_2$ is put down a hole or sequestered and used for tertiary oil recovery in the Weyburn oil fields.

So we are doing just exactly what you described, producing natural gas from coal, capturing the $CO_2$ and sequestering it and producing more oil and gas in the process.

I think, Mr. Sieminski, your point is exactly right. The problem, the reason we are not doing more and more and more of it is we have got to make it economically viable, and that means we both have to reduce the cost of carbon capture and there has to be enough benefit in the molle patch to use $CO_2$ for tertiary recovery rather than water floods or something along those lines.

Mr. SIEMINSKI. That's correct.

Senator HOEVEN. My question to you is right now today the world price for oil as posted for Brent crude is $63 a barrel. The domestic price for oil is West Texas Intermediate crude. That's $55 a barrel. That means our producers get $8 less per barrel of oil than foreign producers.

So here we are locked in a battle to determine who is going to supply energy in the future, who is going to produce energy in the future, and our producers are at an $8 disadvantage against producers in places like the Middle East and Russia and Venezuela.

At the same time our consumers do not benefit because gasoline is benchmarked off world crude which is the higher price at Brent, so we lose both on the production end which hurts our ability to produce more energy, be more energy secure here at home. It also hurts our consumers at the pump, so we need to lift the export ban on oil. Everybody wins in that equation all the way from the producer to the consumer at the pump.

How can you help get that information out so that when we go to the Senate Floor we can get more than 60 votes and pass that legislation?

Mr. SIEMINSKI. Well, Senator Hoeven, we appreciate the support that you've shown us over the years in terms of our budget. Our budget enables us to do that, and I know that you're there.

You know, on this difference, it actually goes back to something that Senator Murkowski mentioned at the very beginning of the hearing that measurement of the WTI price is in the midcontinent at Cushing, Oklahoma. And as long as you can't consume as much of oil in that midcontinent area as you're producing, prices are going to be depressed. And you know very well, Senator, that prices can often even be lower in North Dakota because you're even further away from the refineries that will consume the oil.

I think that the infrastructure issues are critically important as we build out.

Senator HOEVEN. I am glad you brought that up. Thank you. [Laughter.]

Mr. SIEMINSKI. As we build out the infrastructure some of that differential could disappear and our producers would be getting closer to world prices.

Senator, you also missed an interesting dialogue between Senator Murkowski and the Senator from Hawaii. Hawaii is paying very, very high prices for electricity. And you know, that might be helped if you could get LNG from Alaska down to Hawaii, for example.

I remember last time I was up here Senator Baldwin was saying that the paper industry in Wisconsin was really getting hammered by high energy prices, and they don't use a lot. They could use more natural gas there, and I remember you saying that you'd love to sell some of that gas that's not being used and get that down to Wisconsin.

Those are the kinds of infrastructure issues that need to be addressed so that we can get the energy from where it's being produced to where consumers need it.

Senator HOEVEN. So infrastructure is vital. But also in your expert opinion the ability to export LNG, liquefied natural gas, and the ability to export oil will benefit our consumers because we will produce more here at home. The price at the pump is benchmarked off the world price. More supply pushes prices down so the consumer benefits. Is that correct?

Mr. SIEMINSKI. I'd say that in general, trade generally tends to boost GDP and GDP is obviously, ultimately, helping everybody. I think there are some very serious regional issues that——

Senator HOEVEN. But apart from the regional issues, overall you are always going to have imbalances, particularly when we can't when we are blocked from building vital infrastructure. To build an energy plant for the country we need the right mix of pipelines, rail and road. We need the energy infrastructure. We need transmission lines.

You cited some great examples, but producing more energy at home, more supply here at home, helps our consumer, correct? At the same time that prices are priced off a global market.

Mr. SIEMINSKI. That is correct.

Senator HOEVEN. And we are competing in a global market.

Mr. SIEMINSKI. I agree with that. Yes, sir.

Senator HOEVEN. Yes, sir.

My second question is the imbalance of light and heavy. What can we do to help our refiners modify their refineries so that we can process more of the light, sweet crude we produce which would help us, of course, with energy production here at home, energy security and again, benefit the consumer? What kinds of things can we do to help our refiners address this imbalance of light and heavy crude?

Mr. SIEMINSKI. The——

Senator HOEVEN. In terms of refining capacity?

Mr. SIEMINSKI. Yeah, you know, I'm not—beyond the issues that have been talked about in terms of what happens if you allow exports or don't allow exports EIA has been looking at this from a couple of different angles.

In April, we published earlier in this month, we published a paper on the options for petroleum refineries to run more light, sweet crude oil. So it was, kind of, along the lines of what they could do. You know, what are the things they can do in a refinery to run more light, sweet crude oil?

In another month and maybe by the end of this month we will have a report out that looks at the question of well what would they do given the existing set of costs and so on. And it will try to look at the question of what refiners would actually do in response to the current production of light, sweet crude oil and the refining kit that's available to run it.

The final report that we'll have out, I hope in June, will look at the costs, the impacts on production and the impacts on trade from either having the crude oil export ban, you know, or rules continue as is or changing those to make it more open.

Senator HOEVEN. So you said your next study will actually focus on some of the things refineries can do to address——

Mr. SIEMINSKI. We will do that. Yes, sir.

Senator HOEVEN. This imbalance between light and heavy and process——

Mr. SIEMINSKI. Right. We'll have that out relatively soon.

Senator HOEVEN. Madam Chair, I do have one more question. I am certainly willing to wait, but I would like to ask one more question.

The CHAIRMAN. We are going to do one more quick round, if you do not mind waiting.

Senator HOEVEN. Thank you.

The CHAIRMAN. Okay.

Mr. Sieminski, thank you for, kind of, the continual plug here for Alaska to move its LNG. We believe, of course, that we have considerable opportunity, not only for our state, for Hawaii, but what it represents beyond that. Know that we are working it, but the need is clearly there.

We are talking about the infrastructure and the alignment that is going to be needed going forward. I appreciate some of the specifics you've outlined here just with Senator Hoeven, but as you know within the State of Alaska we have an extraordinary piece of energy infrastructure, the TransAlaska pipeline.

Right now we are moving about 500,000 barrels a day, but your forecast projects 420,000 barrels a day by 2020, 320,000 barrels per day in 2025 and then just 180,000 barrels a day when we hit 2035. This is a terrifying prospect for us right now because the concern is that there gets to a point where that throughput is so low it brings into question the ability of that pipeline to function as safely as we need it to be.

If it cannot function safely then we stop moving the oil through the line, and when you stop moving the oil through the line the law requires that we decommission that incredible energy infrastructure. For those who wonder how long it might take to permit a new TransAlaska pipeline, I do not even want to speculate about where that might take us.

So when we are talking about infrastructure and the need to realign, I think we also need to recognize that we have very good infrastructure that effectively needs to be filled up in Alaska's case.

The question to you this morning is in your reference case I am assuming you have factored in a steady state in Federal policy.

Mr. SIEMINSKI. Right.

The CHAIRMAN. Some of what we are dealing with in Alaska, of course, is being able to access other areas, other Federal areas so we can fill up that pipeline whether it may be the ANWR area, our offshore prospects or being able to tap into some resources within the National Petroleum Reserve. How does the issue of access factor into your projections?

Mr. SIEMINSKI. Well we do follow existing law and regulation, and unless there are changes to the ability to lease in the Arctic refuge, for example, or we see other things like a lowering in the cost of doing shale oil developments. There are shale oils on the North Slope of Alaska that right now it seems in our models uneconomic to do that.

At $100 it was getting closer at $60 or $75, maybe not as much, but those sorts of things would enter into those calculations.

Senator, we did do a study specifically of the Alaska oil pipeline in, I think it was the 2013 Annual Energy Outlook, where we highlighted the fact that there could be a step change down at some point as production flow through the TransAlaska pipeline gets down to about 300,000 barrels a day. The mechanical ability of the pumps to work at that level of throughput comes into question, and it's very possible that it would have to drop.

It was one of the things that we thought should be looked at because a change of 300,000 to 500,000 barrels a day in the global oil markets is enough to make a difference, and it was something that we wanted to look at.

I understand your concern. It's policy issues. That's another one of those policy issues that EIA generally tries to provide the facts so the people can understand what's happening but not a recommendation to——

The CHAIRMAN. That is greatly appreciated, but I think it is important for people to not assume this is just going to be continuing with a flow from the north if we cannot have access to these resources, those reserves.

Mr. SIEMINSKI. Right.

The CHAIRMAN. That are, in fact, in place up there.

Can I just ask one quick question about, again, Alaska LNG and the fact that the reference case does include a completion of the Alaska LNG project? Which, of course, I fully support and Alaskans fully support. But in terms of the economics that derive from that project coming out of Alaska, can you speak briefly to that?

Mr. SIEMINSKI. Sure. We have LNG from Alaska coming in around the year 2025. It seems like a long way away, but 10 years is not a lot when you are developing a project the size and scope associated with that.

It is dependent on our reference case forecast for oil hitting $75 a barrel next year and then moving up over time. Higher oil prices make LNG more attractive in overseas markets where fuels tend to get priced against each other where there's oil linked contracts for gas. So the higher oil prices would help that.

Two other cases that we ran, Senator, we don't have Alaska LNG coming in.

One of those is the low oil prices case. As I said low oil, low global oil, prices just make it harder for the economics to work for Alaska LNG.

And the other one, interestingly, is high oil and gas resource case. If there are more oil and gas resources let's say in the lower 48 states relative to Alaska then Alaska's standing in the queue of projects that would get done on an economic basis might slip down. So there's a lot of moving parts.

The reference case though does have LNG from Alaska coming in. And it would, I think, most of it would probably go to Asia. But I think some of that actually might end up in Hawaii as well.

The CHAIRMAN. As I have told Senator Hirono, Hawaii is on the way to Asia. [Laughter.]

So we can make that work. Thank you for that.

Senator Cantwell.

Senator CANTWELL. Just to clarify on that point. So Alaska being able to export LNG and possibly being successful on a pipeline would not have an impact on the U.S. market?

Mr. SIEMINSKI. It would have a minimal impact mainly because it's separated from the lower 48 state markets.

So it would have more of an impact on the global markets. I mean, you know, again, to the extent that you get more fuel whether it's oil or gas or renewables into the markets you're going to tend to lower prices. Certainly that would be the case for oil and gas. And the net effect of that would be to bring fuel costs down for everybody.

Senator CANTWELL. Can I talk for——

Mr. SIEMINSKI. And Senator Cantwell, if I, just a second.

We are working really hard on a study of gasoline on the West Coast markets. And we hope to have that out fairly shortly. And I think that's something that you'd be very interested in.

Senator CANTWELL. Good because I gave you up to the end of this year. Now that it is going to be very shortly, I love that answer. So, thank you.

Mr. SIEMINSKI. Right.

Senator CANTWELL. I liked this part of your report on page four about liquid fuel consumption falling, and I am sure that is directly related to transportation fuel.

Mr. SIEMINSKI. That's correct.

Senator CANTWELL. Do you see that trend continuing?

Mr. SIEMINSKI. In the reference case total liquid fuels consumption comes down a little bit over the forecast period. It's very different between the different fuels of gasoline comes down pretty sharply. Diesel fuel and jet fuel actually go up a little bit. The reason jet fuel goes up is there's just more people flying.

Senator CANTWELL. Yes.

Mr. SIEMINSKI. And diesel fuel——

Senator CANTWELL. Which is why——

Mr. SIEMINSKI. Diesel fuel goes up because, with population and economic growth, there is more trucking occurring and train transportation as well. And both trucks and trains use diesel fuel.

Senator CANTWELL. Well, we are definitely working on those on the R and D side. [Laughter.]

Both on jet fuel and on other biofuels, so that is why it is so important. But——

Mr. SIEMINSKI. Biofuels are in that forecast too in a portion of the diesel fuel category there's bio diesel.

Senator CANTWELL. I am sure tax credits, but I am sure the tax credits are not. So then their predictions are not as robust. Okay, we will not go there.

Mr. SIEMINSKI. We would love to get help from the Senate and House of the United States on clarity on the path forward for those tax credits. It would help in our analysis a lot, but I'm not counting on it.

Senator CANTWELL. One of my top priorities for energy is to get that predictability. We are going to continue to see a savings at least within transportation fuel. We are going to continue to see that consumption savings.

Mr. SIEMINSKI. Right.

And it's an important part of our forecast for the question of net oil imports and the benefits to the economy as we produce more of the fuels that we're consuming. The flatness in the overall liquids fuels and the drop in gasoline consumption that's being encouraged by fuel efficiency standards and changes to other fuels in the transportation sector helps to keep that oil import number down at that 15 percent level that we have in the reference case. And that's a huge improvement over what the U.S. situation was just ten years ago.

Senator CANTWELL. Yes, I agree. You had some interesting projections on hydro. So what are some of the factors that are driving those projections? It sounds to me like there are efficiencies being implemented, new turbo——

Mr. SIEMINSKI. One of the charts in the Annual Energy Outlook basically shows all renewables. And EIA includes hydro as one of the renewables. We, right now, hydropower is just about equal to all of the other renewables combined.

But we think hydropower over the 25 year forecast is going to be relatively flat. The reasons behind that is there just aren't that many more places where you're going to put big dams in the United States. So with hydropower relatively flat and increases coming in in other renewables like solar and especially wind—we have a lot of growth in wind that by the end of our forecast period wind generation, actually exceeds hydro generation for the first time ever in the United States.

And it could then happen sooner. Yes, it could, you know, if we ran that in the no sunset case we would have more growth than wind and solar than are shown in our current charts.

Senator CANTWELL. Thank you for bringing that point up about wind. I was definitely going to go there, so thank you for explaining that.

On hydro, I just want to emphasize how much new technology is helping us drive efficiencies there.

Mr. SIEMINSKI. Right, to the extent that better generators can convert the energy that's in the water into something that's deliverable across the lines. It would be a real benefit out in the Northwest. Also the transmission, I mean, we're making progress in the efficiency associated with the transmission grids and the more of that electricity that you can get to the end user the better off everybody is. And so there is progress being made in that area.

Senator CANTWELL. We definitely want a dialogue with you about how you would start to model some of that information. Again, you are modeling what is in place, right, not what is not in place?

Mr. SIEMINSKI: Right.

Senator CANTWELL. We are seeing huge efficiencies from smart grid technologies, and they are just basic things in the various sectors, everything from synchophasors to other things, resulting in huge savings. So I think your report is actually showing the end result in some of that data already, and that is why we want to keep emphasizing how important efficiency is. So thank you.

Thank you, Madam Chair.

The CHAIRMAN. Senator Hoeven.

Senator HOEVEN. Thanks, Madam Chair.

I just had the one question that I wanted to follow up with you on.

I know you have addressed it to some extent but let's talk for a minute about the impact on Iran's economy that would result from a lifting of the sanctions. You addressed some of the front end aspects in terms of the oil that is currently being stored, but the fact is our sanctions have reduced Iran's ability to sell oil from 2.5 million barrels a day in 2011 down to 1.1 million barrels a day in 2013. Very, very significant for an economy that is pretty much entirely dependent on petro sales.

Would you please talk about both the immediate term and the longer term impact on Iran's economy that lifting of the sanctions would have.

Mr. SIEMINSKI. I think in very rough numbers, Senator, that you could think about another million barrels a day of oil could be out on the global markets from Iran at $60 to $75 a barrel.

Senator HOEVEN. Again at a higher price than our domestic producers get by $8 a barrel. Correct? 63 Brent versus 55——

Mr. SIEMINSKI. I think we'd want to look at that to try and see whether or not the quality of the oil that Iran is selling is, what the differentials would be there. But in rough terms if you just said $60 at a million barrels a day it's $60 million a day of additional revenue that Iran would be receiving.

Senator HOEVEN. Thank you.

Mr. SIEMINSKI. About $25 billion a year. I wish I had a million barrels a day of production.

Senator HOEVEN. So you would say it is a huge impact to their economy?

Mr. SIEMINSKI. Oh yeah, it would be very big.

Senator HOEVEN. Thank you, I appreciate it.

Thank you, Madam Chairman.

The CHAIRMAN. Senator Hoeven, I appreciate you drilling down on that. There have been several questions about the impact of removing these sanctions on Iran and just the value to Iran and how it effectively puts us at a disadvantage then when we are not able to export our oil into that global market.

I think it does just push the discussion on what we do here in this country to relook, critically relook, at these export policies that are inhibiting not only our job growth, our economic opportunity, but really our ability to utilize a resource, a strategic resource, for the benefit of the geopolitics surrounding, not only oil, but other resources as well and how the United States can play as an international leader with, effectively, this oil diplomacy, if you will.

What we are seeing right now playing out in real time should be a reminder to us that we have in place policies that were put in place many decades ago for reasons that are no longer necessarily applicable. I think that is our role and our job here as a Committee to look at these policies and see if it is time that we address and change them. I believe it is time, and I think you would agree as well.

Senator HOEVEN. Madam Chairman, if I may, I want to again thank you for holding this hearing. I think it is so important because it not only demonstrates the economic benefit and impact of the right policies here at home, but also the geopolitical influence we can have on a global basis with the right approach both in terms of what we do with our energy policy and in terms of what we do with our international approach to energy as part of diplomacy. I think you have done an excellent job with the Administrator highlighting that here today.

It is so important on all these fronts, not just on the economic front here at home, but the impact we can have in terms of foreign relations and diplomacy above and beyond military strength. We can have a real impact here, and I think the Administrator highlighted this when he talked about a million barrels a day and what that does for Iran's economy if these sanctions are lifted.

We have to understand how powerful that sanction is and certainly make sure that when we are dealing with something like a nuclear Iran that we understand the leverage we have with these sanctions. So I thank you, again, for holding this hearing today, Madam Chairman.

The CHAIRMAN. I think we also need to appreciate that these sanctions that have been in place, that have brought Iran to the table with these negotiations, these sanctions could not have been near as effective if we did not have our own resources to rely on. The figures that you gave us, Mr. Sieminski, were back in 2005 when we were importing 60 percent of our oil. Today, it is 15 percent. That is incredible. It is absolutely incredible how quickly we have moved that dial.

When we were more than 50 percent dependent on a resource coming from others, including others who do not like us, there is a vulnerability. When we can move to the place where we are today where we are not only in a position to influence and lead but to ultimately get to that point where we are a net exporter, this is a dramatic change, a dramatic shift, and I think only for the betterment of our country.

So this is all good information today. I know you have, again, couched all of this in terms of these are reference cases. We are not always right, but you hope to be proven not wrong today. I appreciate that. [Laughter.]

The CHAIRMAN. We recognize, again, that this is projective. You are projecting out. It is not predictive. We put it in those terms, but I think the good work that EIA does not only with your Annual Outlook, but truly on a day-to-day is greatly appreciated. We thank you and your work and that of your great staff that stand behind you.

Know that we will use this as a resource going forward. I understand you will be traveling to the State of Alaska, so you will have an opportunity to become even more informed with the——

Mr. SIEMINSKI. Senator, before you hit the gavel, just 30 seconds.

The CHAIRMAN. Please.

Mr. SIEMINSKI. The impact of U.S. production goes beyond just the Iranian sanctions issue. Back in 2012 and '13 there were some really serious interruptions in oil production in countries like Libya.

The CHAIRMAN. Libya.

Mr. SIEMINSKI. Sudan, Yemen, Syria and others. They add up to a huge amount of oil, over 2,000,000 barrels a day, at one point approaching something like 3,000,000 barrels a day. And had it not been for the growth in shale production in the U.S. and production in a few other countries, including Canada, the price of oil would have been a lot higher.

Obviously that would have been a benefit to producers but the overall impact to the economy could have been pretty devastating.

And I think that the growth in production in the U.S. played a very important role in stabilizing that global oil markets.

The CHAIRMAN. That is an important factor to keep in mind. Because when we do not see the disaster that could have come, it is like, well, nothing really bad happened. The fact of the matter is nothing really bad happened because we had built a cushion, a cushion that we did not have before. It becomes more difficult for people to appreciate exactly how significant that was, that we were able to weather those pretty considerable disruptions.

Mr. SIEMINSKI. Right.

The CHAIRMAN. Because of what we were producing here in this country at an unprecedented rate, again, going from 60 percent reliant on imports to the level that we are at today.

So we thank our friends from North Dakota. It really bothers us that North Dakota has pushed Alaska out of its leadership position there, but we are just glad somebody is doing it.

Senator HOEVEN. If I may, Madam Chairman? You made such a great point today. You talked about the Alaskan pipeline and how it is in jeopardy if we do not have the right policies.

The CHAIRMAN. Yes.

Senator HOEVEN. So that we can continue to produce domestic energy rather than rely on energy from the Middle East. You have highlighted that so well here today with the Administrator. I hope people are really paying attention, not just what it means to us here at home and our economy, but to our security in the world.

The CHAIRMAN. Yes.

Senator HOEVEN. I think this hearing has really brought that out very dramatically. So, thank you.

The CHAIRMAN. I wish all 100 of us were here instead of just the two of us concluding it. [Laughter.]

But we will make sure that that word gets out.

Again, Mr. Sieminski, thank you so very much.

Mr. SIEMINSKI. Senator, thank you very much. Senator Hoeven.

The CHAIRMAN. We stand adjourned.

[Whereupon, at 12:10 p.m. the hearing was adjourned.]

## QUESTIONS FROM SENATOR JOHN BARRASSO

Q1. In response to Senator Franken's question about the effects of exports of liquefied natural gas (LNG) in Minnesota, you said that "a state like Minnesota actually has a fairly decent industrial base in things like heavy construction and services that would be useful in the [natural gas] producing industry so there would be opportunities for the state of Minnesota to sell" to natural gas producers. Would you please elaborate on the economic opportunities that LNG exports would provide Minnesota?

A1. The following manufacturing industries supply goods needed by industries involved primarily production of oil and gas: non-metallic mineral products, primary metals, fabricated metals, machinery, computers, and transportation equipment. In 2013, these industries accounted for 42% of Minnesota's manufacturing value added, contributing $23 billion out of the total Minnesota manufacturing value added of $56 billion. Other service industries support increased oil and gas production, including finance, transportation services, and information services all of which contributes to Minnesota's gross state product. Recent figures for the service sector's contribution to Minnesota's economy are not available, but University of Minnesota Extension analyses indicate regional strength in these activities.

Q2. You also stated that "putting more U.S. natural gas into the global markets would probably tend to lower the prices for all fuels, including oil, which would then be reflected in lower gasoline prices in the U.S." Some might find this to be counterintuitive. Would you please explain in detail how U.S. natural gas exports would lower global oil prices and lower gasoline prices in the U.S.?

A2. The additional supply of natural gas into the world market from exports out of the United States could put downward pressure on global natural gas prices. Lower global natural gas prices would tend to encourage international consumers to invest in technologies that consume natural gas in lieu of petroleum products, such as gas-fired power plants and natural gas vehicles.

Any displacement of petroleum products by natural gas in the global market would tend to reduce demand for crude oil and lower global crude oil prices. As crude oil prices are the main determinant of gasoline prices and as changes in crude oil prices are passed through to gasoline prices, lower crude oil prices would, all other things equal, result in lower gasoline prices. Although these linkages are clear, the extent to which they would actually change crude oil and gasoline prices cannot easily be determined.

The relationship between crude oil prices and U.S. gasoline prices is discussed in detail in a recent EIA report *What Drives U.S. Gasoline Prices*. The report presents the results of analysis that demonstrates global (Brent) crude oil prices are more important than U.S. domestic (WTI) crude oil prices as a determinant of U.S. gasoline prices. As a result, lower global crude prices resulting from increased U.S. natural gas prices exports would tend to lower U.S. gasoline prices. It is important to understand that U.S. gasoline prices are linked to global crude oil prices through U.S. participation in the global gasoline market. Gasoline is a globally traded commodity and the United States is an active participant in the global gasoline market as both an importer and exporter. The United States relies on imports into the U.S. Northeast, much of which is produced in Europe from global crude, and exports gasoline from both the Gulf Coast and the West Coast.

**QUESTIONS FROM RANKING MEMBER MARIA CANTWELL**

Q1. In EIA's new crude-by-rail (CBR) data series, CBR activity is tracked between pairs of Petroleum Administration for Defense District (PADD) regions (inter-PADD), within each region (intra-PADD), and across the U.S.-Canada border.

a) Are there breakdowns of CBR movements specifically by state instead of just by PADD, especially for Washington within PADD 5?
b) Are there plans to add state-level granularity to this data set?
c) What are the challenges associated with collecting and publishing state-level data for CBR?

A1. a) No, there are no state breakdowns of CBR data within a PADD.

b) No, there are no plans to add state-level granularity.

c) The primary challenges are accuracy and protecting confidential data. The data are estimated from a Carload Waybill Sample, and the sampling approach does not guarantee that all the appropriate rail movements have been sampled, especially within a region or state where short line railroads are likely operating. Revealing confidential data is likely at the state level where fewer than three companies' data will be revealed or one company may represent more than 60% of the movements.

Q2. EIA initiated the new CBR series with monthly data from January 2010 through the January 2015 reporting month.

a) What are EIA's plans for projecting future CBR movements going forward?
b) What are the challenges of projecting CBR movements?
c) How are CBR movements represented in the modeling and results of the Annual Energy Outlook?
d) How are CBR movements represented in the modeling and results of the Short-Term Energy Outlook?

A2. a) EIA's immediate plans include improving the CBR data by verifying accuracy of the sampled movements and working with stakeholders, including Canada's National Energy Board and the Association of American Railroads (AAR) to verify inclusion of all CBR imports from Canada and improving near-month estimates.

b) There are many challenges involved in predicting a lumpy time series that can experience large month-to-month changes due to the timing of unit train unloadings, trade-offs with other petroleum and biofuels moved by rail as well as crude oil moved by other modes (pipeline, tanker or barge), responsiveness to spot oil prices and refinery economics, seemingly unusual movements due to the regional boundaries of logistics, uncertainty surrounding derailments and potential regulations, etc.

c) CBR is not directly represented in AEO2015. When estimates of crude delivery to refineries were made by AEO analysts in 2014, we did not have historic information on inter-regional and cross-border CBR movements. Our assumptions about transportation in specific regions in future AEOs will address the importance of rail as we now understand it.

d) CBR is not directly represented in STEO, which is a national-level forecast without regional balances. EIA's analysis and forecasting of regional and national petroleum markets is expected to be greatly enhanced through the use of this newly released data.

Q3. In EIA's testimony, it was stated that the Dakotas/Rocky Mountains region will likely see the strongest growth in crude oil production.

a) How would further increases in production from that region affect movements of crude oil throughout the country, especially by rail?

b) What have the patterns in the historical data shown us to date?

A3. a) The Dakotas (PADD 2) and Rocky Mountains (PADD 4) are dependent on rail, but pipelines move more crude than rail from these regions. In 2014, rail moved almost half of the crude from PADD 2 across PADD borders and one-third of the crude out of PADD

4. Growth in rail movements from PADDs 2 and 4 depend on the extent of crude pipeline development.

b) The patterns in historical data have shown that there is tremendous potential for growth in rail movements, which grew from almost zero in 2010 to 266 million barrels from PADD 2 and 97 million barrels from PADD 4 in 2014. Pipeline movements have also grown from 2010 to 2014, but the rate of growth for rail has been greater.

Q4. Senator Cantwell noted an ongoing concern that EIA continually underestimates the potential of renewable energy in the Annual Energy Outlook reports.

a) Do you believe the Annual Energy Outlook's modeling assumptions are keeping up with the rapidly decreasing costs of renewables, particularly wind and solar?

b) How can this be improved?

c) What kind of resources does EIA need to ensure its modeling tools and surveys are keeping up with developments in these markets?

A4. Over the past six AEO cycles, EIA has about an even record of overestimating and underestimating near-term capacity additions for wind in the U.S. when accounting for projections that correctly align with Federal tax policy for wind. That is, for the years that the AEO or its side cases indicated the Production Tax Credit was in place, and it actually was in place, EIA has a well centered wind capacity estimate. While AEO renewable projections generally perform well when compared with outcomes consistent with the modeled laws and policies, the pace of development in the solar PV market has presented a challenge. As a result, EIA has increased its attention to short-term changes in capital costs as well as ensuring the accurate representation of projects planned for the near term.

a) While tracking changes in capital costs of just about any generating technology is difficult due to the lack of timely, consistently collected data, wind and solar markets have been somewhat easier to track because of the regular release of market reports from DOE, as well as from EIA's own periodic assessment of project costs. While EIA's assessment is intended to provide a more comprehensive look at the full scope of costs incurred by developers than the methods used by DOE, the DOE reports are produced more frequently, and have allowed EIA to adjust costs as warranted for each AEO cycle when both reports have been available (approximately the most recent five AEO cycles). Other, less reliable assessments for these costs, particularly solar PV costs, are available, and EIA monitors these assessments because they provide still more frequent views of cost dynamics (quarterly, compared to annual DOE reports and the less frequent EIA reports).

b) Capital cost estimation is particularly challenging for technologies for which few if any commercial scale projects have recently been undertaken in the United States. Unlike wind and solar, with their substantial and recently installed capacity base to draw from, many technologies, such as coal, nuclear, and advanced carbon capture plants have little to no recent domestic experience from which to draw capital cost estimates. Even with technologies like combustion turbines and combined cycle units, there are no comparable efforts by DOE or other sources to comprehensively track installation costs. EIA is partially addressing shortcomings in capital cost data collection by including limited questions on capital cost on the Form EIA-860 (The Annual Electric Generator Report). Even to the extent that EIA is able to consistently collect actual capital cost data from new utility-scale plants, the data may have limitations in terms of the lack of consistent understanding of the survey questions by respondents, as well as timeliness of the cost information. Additionally, this approach will still not produce reliable information for technologies without recent construction activity. Therefore, EIA expects to continue to use private, DOE, and EIA-commissioned studies to provide the most complete view of capital costs and capital cost trends for wind, solar, and the wide variety of other technologies evaluated by EIA.

c) EIA regularly assesses its analytical and statistical programs and develops program and funding requests to enable them to reflect the changing dynamics of the energy landscape. EIA's FY 2016 budget request of $131 million includes funding to address these and other renewables related challenges faced by EIA.

**QUESTIONS FROM SENATOR SHELLY MOORE CAPITO**

Q1. Mr. Sieminski, as you know, coal and natural gas are extremely important to my home state of West Virginia. According to your agency's outlook for 2015, coal use in a reference case grows from 18 quadrillion BTU in 2013 to 19 quadrillion BTU in 2040. The outlook also stipulates that said reference case does not take the EPA's proposed Clean Power Plan into account. Does this report maintain that, absent this Administration's Clean Power Plan, coal usage in the US would increase through 2040?

A1. The *Annual Energy Outlook 2015* (AEO2015) Reference case takes into account existing legislation and regulations and therefore excludes EPA's proposed Clean Power Plan (CPP). However, the projections do include EPA's Mercury and Air Toxics Standards (MATS), the Northeast's Regional Greenhouse Gas Initiative (RGGI), the California Global Warming Solutions Act of 2006 (Assembly Bill 32, or AB 32), state Renewable Portfolio Standards (RPS), and an assessment of investment risks associated with high carbon dioxide emitting projects.

Coal use is projected to rise by 0.7% per year between 2013 and 2024 and then level off, growing by a more modest 0.1% per year thereafter through 2040. Coal consumption is 5.5% higher in 2040 than in 2013, but still 6.5% lower than peak coal consumption in 2007. This outcome is primarily the result of increased utilization of existing coal plants, from 60% in 2013 to 75% in 2040, which occurs as a result of rising natural gas prices relative to coal in the Reference case. Competitive natural gas prices, low electric demand growth, relatively high capital costs, and existing legislation and regulations result in 40 GW of retirements from 2013 to 2025 and less than 1 GW of coal-fired additions through 2040 in the Reference case.

As illustrated in the AEO2015 side cases, higher economic growth and higher natural gas and oil prices, can lead to greater consumption of coal than represented in the Reference case, but lower economic growth can also lead to lower coal consumption compared to the Reference case. The High Oil and Gas Resource case shows coal consumption falling from 2013 levels under natural gas resource and technology assumptions that result in natural gas prices below $4 per million btu through 2033.

Q2. Your agency's 2015 Top 2015 100 US Oil and Gas Fields report released in March of this year notes that the Marcellus – a shale formation very important to my home state of West Virginia for obvious reasons - became the number one U.S. gas field by estimated proved reserves in 2013. In fact, in the AEO2015 reference case, over half of the increase in shale gas production comes from two formations – one of which is the Marcellus. Shale gas production has been an economic driver for West Virginia and other states in the region. Additionally, the *Annual Energy Outlook 2015* report states that "In the AEO2015 Reference Case, the U.S. becomes an overall net exporter of natural gas in 2017, one year earlier than in AEO 2014." The opportunity is clearly massive. In the meantime, there are some very serious regulatory threats coming at the industry that could negatively affect natural gas producer's ability to continue their safe and responsible development of natural gas including the new BLM hydraulic fracturing rule and the to–be–proposed methane regulations as promised by the Obama Administration under 111(d). What assumptions about these regulations did you incorporate into your projections? How would you think the implementation of these regulations affect your projections?

A2. The cases in EIA's *Annual Energy Outlook 2015* (AEO2015) assume that current laws and regulations remain generally unchanged throughout the projection period. The BLM recently released final standards regarding hydraulic fracturing on public and American Indian lands were not included, as the modeling for AEO was finalized prior to the March 20, 2015 release of those standards. Similarly, the methane regulations under 111 (d) were not included as they have not been proposed or implemented.

EIA has not produced an analysis regarding the effects that either of these regulations would have on natural gas production in EIA's projections.

**QUESTIONS FROM SENATOR JOE MANCHIN III**

Q1. In the AEO'15 Reference case, traditional electricity baseload assets (coal and nuclear) see existing units' average age grow considerably, as few new units are introduced. After near term retirements, coal-fired generation experiences 1 GW of new capacity and approximately 250 GW remains in 2040, with an average unit age of approximately 65 years. For nuclear generation, by 2040 and the average age is approximately 60 years for roughly 100 GW of capacity. 10 GW of new coal and nuclear capacity over 25 years stands in contrast to 18 past years with introduction of more than 10 GW of coal and nuclear capacity in one year. These traditional baseload assets have produced over two thirds of all electricity generation in the U.S. over the last 16 years. Has EIA considered the reliability implications and the size of deferred costs for asset replacement, associated with allowing roughly 350 GW of baseload assets to reach an average age of 60 years or more, by 2040?

A1. EIA does consider age-related expenses for baseload assets. As noted in the Assumptions documentation to the Annual Energy Outlook (AEO), an additional $7 per kW capital charge for fossil plants and $33 per kW capital charge for nuclear plants in constant 2013 dollars is added to the annual fixed operation and maintenance (O&M) costs for plants beyond 30 years of age. These added age-related costs account for major repairs or retrofits, decreases in plant performance, and/or increases in maintenance costs to mitigate the effects of aging. In the AEO, a generating unit is assumed to retire if the expected revenues from the generator are lower than the annual going-forward costs – including age-related costs, fuel, O&M costs and annual capital additions, which are unit-specific and based on historical data -- and if the overall cost of producing electricity can be lowered by building new replacement capacity. The average annual cost attributed to capital improvements for existing plants are $17 per kW for coal plants and $22 per kW for nuclear plants (in 2013 dollars).

Reserve margin —the percentage of capacity in excess of peak demand required to adequately maintain reliability during unforeseeable outages—in the AEO2015

Reference case is set based on regional Reference Margins reported to NERC and ranges from 14% to 17%. No further assumptions are made in the AEO2015 regarding the reliability or availability of aging generation assets.

Though not included in the menu of side cases for the AEO2015, the AEO2014 did include a series of side cases evaluating the impacts of higher levels of coal and nuclear retirements. For instance, in the AEO2014 Accelerated Coal Retirements case, higher fuel prices and O&M costs serve as a proxy for assumptions that might lead to increased coal plant retirements. In this case, 110 GW of coal plants retire by 2040, 117% more than the AEO2014 Reference case. Across these various retirement cases, increases in natural gas-fired generation primarily compensate for lost baseload capacity resulting in increases in the delivered price of natural gas to the electric sector and in the aggregate retail electricity prices of up to 11% and 12%, respectively.

Q2. Particularly, for the 250 Gigawatts of coal units remaining in 2040 (in the Reference case), with an average unit age of approximately 65 years, the expectation of operating at 75% capacity factor (reference page 25 of AEO'15 report) is optimistic and not supported by historic coal unit performance data, based on age. If the units do perform in accordance with historic operating performance of coal plants with age, they will not reliably meet baseload demand requirements and a significant share of generation in the forecast, particularly from 2030 through 2040, will not be available as expected. This topic has been discussed with EIA. Could EIA agree to conduct further analysis with coal and electricity industry specialists to reevaluate their assumptions for the likely operating performance of coal units with age?

A2. EIA recognizes that this is an important area of concern and is involved in efforts to further research the issue. Within the past year, EIA staff conducted meetings with National Energy Technology Laboratory (NETL) staff who have also been investigating coal-fleet aging issues, and both EIA and NETL staff recently participated in a public meeting of the Coal Utilization and Research Council on the subject. EIA is currently considering options for further assessment, such as a public workshop featuring industry and government representation, to further explore the costs and operating performance issues associated with aging coal plants.

Q3. The High Oil Price side case may be especially relevant due to current turmoil in critical energy producing regions of the world. Coal-to-liquids (CTL) appears as a additional domestic technology in support of national energy security, with 710,000 barrels per day forecast in 2040. Integral to this overall process, is an opportunity for Enhanced Oil Recovery (EOR) using the CO2 byproduct of the CTL production. This byproduct can be used in EOR to produce 2 to 3 barrels of additional oil from each ton of CO2. In order to properly reflect the full energy security benefit of the complete CTL with CO2-EOR process, can EIA endeavor to more clearly characterize the total incremental oil production that has been modeled for the entire process? In addition, can EIA identify the amounts of CO2 stored through EOR, in their modeling of this process, as a reflection of parallel climate benefits to be derived in this scenario?

A3. In the High Oil Price case, incremental EOR production using $CO_2$ from CTL increases from 10,000 bbl/d in 2025 to 155,000 bbl/d in 2040, with cumulative incremental crude oil production totaling nearly 560 million barrels over this period. Roughly 185 million metric tons of $CO_2$ is purchased from CTL plants from 2025 through 2040 for use in EOR operations at an average of $85 per metric ton (2013 dollars). The $CO_2$ could remain stored at the original EOR site or extracted for use in other EOR projects. This secondary recycling of CO2 is not reflected in the current AEO but would result in additional incremental oil production. The outlook does not include the additional cost to producers if legislation is passed that would require the EOR operator to guarantee the long-term storage of $CO_2$.

**QUESTIONS FROM CHAIRMAN LISA MURKOWSKI**

Q1. According to the *Annual Energy Outlook 2015* Reference Case (Table A13), EIA projects that in 2040 the United States will be consuming 29.70 trillion cubic feet of natural gas per year, producing 29.90 trillion cubic feet of natural gas per year, and exporting (in net terms) 5.62 trillion cubic feet of natural gas per year. Please comment on the impact such exports may have on natural gas prices.

A1. EIA did not perform analysis in the *Annual Energy Outlook 2015*(AEO2015) on a case that limited natural gas exports. As such, the price effects of exports in the AEO2015 Reference case are not quantifiable.

In October, EIA released the study, at the request of the Department of Energy's Office of Fossil Energy, *Effects of Increased Levels of Liquefied Natural Gas Exports on U.S. Energy Markets* (http://www.eia.gov/analysis/requests/fe/). In this study, EIA examined the impact of increasing LNG export levels in several cases from the *Annual Energy Outlook 2014* (AEO2014). One finding of that study was that increased LNG exports led to increased domestic natural gas prices. For example, starting from the AEO2014 Reference case baseline, which included 7.4 billion cubic feet per day (Bcf/d) of LNG exports, projected average natural gas prices in the Lower 48 states received by producers in the export scenarios are 4% (12-Bcf/d scenario) to 11% (20-Bcf/d scenario) more than their base projection on average over the 2015-40 period. Percentage changes in delivered natural gas prices, which include charges for gas transportation and distribution, are lower than percentage changes in producer prices, particularly for residential and commercial customers. Starting from the AEO2014 Reference case baseline, projected average residential natural gas prices in the export scenarios are 2%

(12-Bcf/d scenario) to 5% (20-Bcf/d scenario) above their base projection over the 2015-40 period.

Note: Dry natural gas production in the *Annual Energy Outlook 2015* Reference case reaches 35.45 trillion cubic feet in 2040. The production volume cited in the question, 29.90 trillion cubic feet, is incorrect. Total supply, which is inclusive of net imports, in the Reference case is 29.90 trillion cubic feet in 2040.

Q2. In the *Short-Term Energy Outlook* released on April 7, EIA notes that Iran holds some 30 million barrels of crude oil in storage and can "ramp up" production by some 700,000 barrels per day by the end of 2016 in the event that sanctions are lifted.

a) If Iran is allowed to export freely to global markets, would you expect most of this new projected production to be exported? If so, approximately how much?
b) EIA notes in the *Short-Term Energy Outlook* that the price of Brent crude oil could fall between $5 and $15 per barrel if sanctions are lifted. All else equal, would you expect domestic U.S. benchmarks to also decline?
c) Generally speaking, would lower domestic oil prices put upward or downward pressure on U.S. crude oil production?

A2. a) EIA estimates that the maximum level of growth in crude oil production that Iran could achieve by the end of 2016 is 700,000 barrels per day, but this is dependent on a host of factors, such as the timing of sanctions relief and any technical output challenges Iran may face. Furthermore, the global oil market is currently well supplied, as reflected by global net inventory builds through 2014 and projected during 2015, even without an increase to Iran's production. Iran's ability to ramp up production will most likely be challenged by its ability to find buyers. If sanctions are lifted, EIA does expect that increases in Iran's crude oil production will result in increases to the country's crude oil exports. However, the amount that Iran can increase production and exports if sanctions are lifted is still unclear, particularly because of current market conditions. The $5-$15 lower price compared to our current forecast reflects the uncertainty surrounding the timing and magnitude of those additional Iranian barrels entering the global market.

b) Yes. In the event that sanctions were to be lifted, and in the absence of other market developments, EIA expects that U.S. domestic crude oil prices would decline by a similar amount compared to international crude oil benchmarks. The relationship between Brent and West Texas Intermediate (WTI) crude oil prices is primarily driven by transportation costs, construction of U.S. infrastructure to transport crude oil, and refinery economics. The presence of additional volumes of Iranian crude oil in the global market would likely have little to no effect on the Brent-WTI spread.

c) Lower domestic oil prices put downward pressure on U.S. crude oil production. However, the relationship is not necessarily directly proportional. Many U.S. crude oil producers (operators) use hedging to lock in the price they receive for production, which insulates them from oil price market fluctuations. Additionally, operators use different business strategies for purchasing drilling rig services and well completion services. Some producers will terminate contracts early, while others will not renew contracts. Finally, cash flow and debt service requirements impact operator production decisions.

**QUESTIONS FROM SENATOR DEBBIE STABENOW**

Q1. The Annual Energy Outlook projects that under existing policies electricity from wind power will increase 32 percent to 86 gigawatts by 2030. The Department of Energy's recent Wind Vision report estimates that the United States could produce 224 gigawatts of wind energy by 2030 -- enough to power 61 million homes. Do you agree with the Wind Vision report that with the right set of policies we could produce three and half times as much wind power by 2030?

A1. The Annual Energy Outlook includes only existing policies. While EIA does not take a position on policy issues, recent EIA analyses show that policy choices can significantly affect projected wind generation. EIA's analysis of EPA's proposed Clean Power Plan rule, issued on May 22, is one example. With the specified requirement that states reduce carbon dioxide emissions from existing generating units to meet state-specific emission rate goals, EIA projects significant wind capacity additions as an important compliance strategy. Projected levels of wind capacity by 2030 vary significantly, depending on the particular case being analyzed, and range from about 142 GW with high availability of natural gas resources, up to 218 GW if the rule results in extensive cooperation among states in meeting the emission rate goals. Although compliance with the proposed Clean Power Plan rule as modeled in EIA's study significantly boosts wind generation, the analysis was not intended to determine policy mechanisms to achieve a specified level of wind capacity, and does not necessarily reflect EIA's view about what other policies may or may not be able to achieve a given capacity level. Furthermore, the study did not consider the same set of policy assumptions implicitly embedded in the Wind Vision report.

Q2. If wind generates between 86 gigawatts and 224 gigawatts by 2030, does the Department project that rates for electricity from wind would be at or below the cost of electricity from fossil fuels?

A2. EIA projects in the AEO2015 Reference case that having reached 87 GW of capacity by 2030, wind's national average levelized cost of electricity (LCOE) is \$73/megawatt hour (MWh) – below the \$76/MWh national average for an advanced natural gas combined cycle plant. The 224 GW estimate cited in the question refers to the Wind Vision Study. An unrelated recent EIA analysis of EPA's proposed Clean Power Plan rule for existing fossil-fueled generating units found that compliance with the proposed rule, assuming extensive cooperation across states, would result in 218 GW of wind capacity by 2030. In this case, in 2030 the average wind LCOE is \$76/MWh, compared to \$68/MWh for advanced natural gas combined cycle. Wind costs are somewhat higher, as increasing wind builds tend to push new wind builds to lower quality, higher cost sites; natural gas generation costs somewhat less, as reduced use of this fuel reduces pressure on natural gas supplies.

However, LCOE comparisons among specific technologies do not necessarily provide an accurate accounting of the economic competitiveness of a technology. It is important to also consider – as do project developers, grid operators, and utilities – the relative values of the technologies as well as the need for new sources of generation and capacity. The existing generation mix, time-of-day and seasonal overlap with generation and demand, and contribution to system reliability also have substantial effect on the value of intermittent resources like wind. A more meaningful assessment of the competitiveness of wind takes into account both its cost and its system value. For a more detailed discussion of this topic, please see EIA's publication "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the *Annual Energy Outlook 2015*".

Given slow growth in electricity demand, new generation from wind may often displace generation from existing capacity whose fixed cost has already been incurred. In such settings, a decision to add wind capacity saves only the fuel cost of the resource it displaced, which in the case of goal and nuclear generators is a small fraction of their LCOE.

In sum, both the cost and value of new wind capacity (and the cost and value of the alternative sources of generation) would be highly sensitive to the particular policy, technology, or market pathway used to promote or encourage capacity additions. Mechanisms such as technology tax credits, carbon taxes, or renewable portfolio requirements all affect the market in different ways, and will distribute costs and impacts in different ways.

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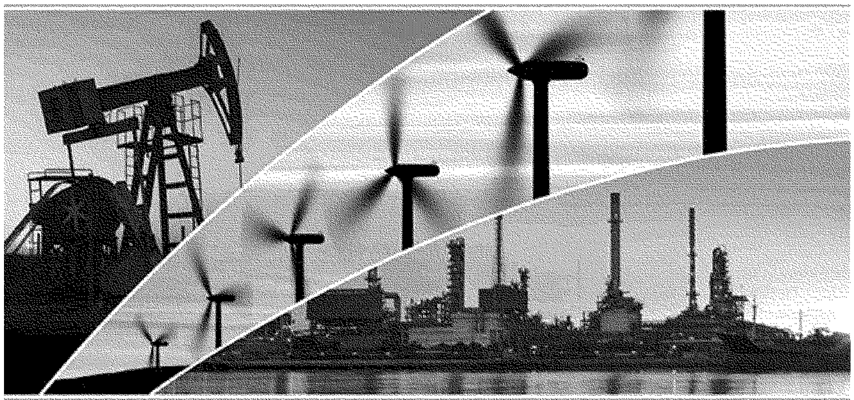
# Annual Energy Outlook 2015

## with projections to 2040



Independent Statistics & Analysis
U.S. Energy Information Administration

## For further information . . .

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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**
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# 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.

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# 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)

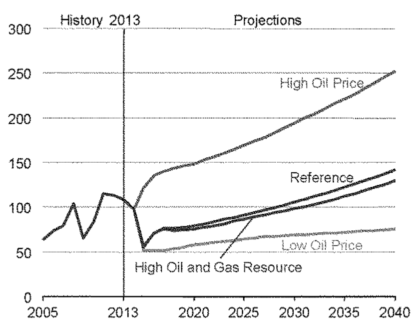
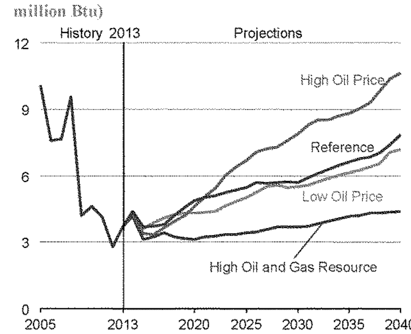



Figure ES2. Average Henry Hub spot prices for natural gas in four cases, 2005-40 (2013 dollars per million Btu)



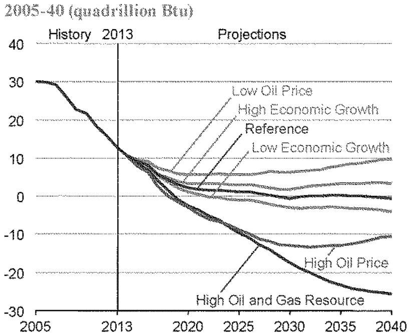
above the Reference case price. Cumulative U.S. exports of LNG from 2015 to 2040 in the High Oil Price case are more than twice those in the Reference case. The opposite occurs in the Low Oil Price case: low Brent crude oil prices cause oil-linked LNG contracts to become relatively less competitive and 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)**

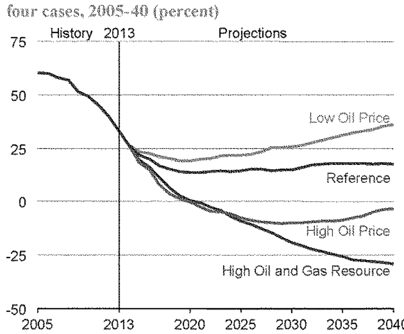
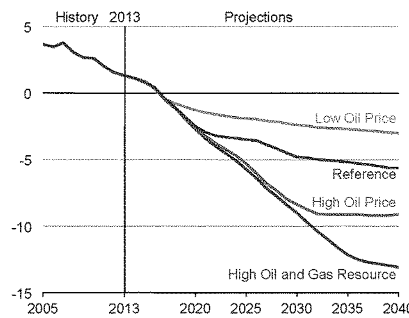



**Figure ES5. U.S. total net natural gas imports in four cases, 2005-40 (trillion cubic feet)**



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.

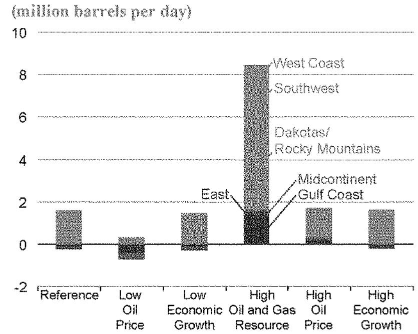
**Regional variations in domestic crude oil and dry natural gas production can force significant shifts in crude oil and natural gas flows between U.S. regions, requiring investment in or realignment of pipelines and other midstream infrastructure**

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

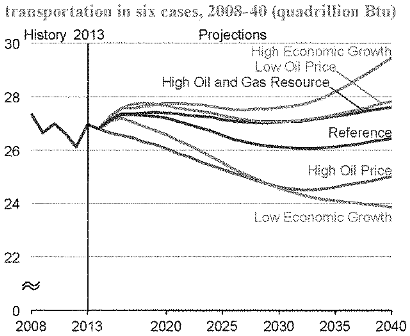
Production of dry natural gas and natural gas plant liquids (NGPL) in the United States has increased markedly over the past few years, and the upward production trend continues in the AEO2015 Reference, High Oil Price, and High Oil and Gas Resource cases, with the High Oil and Gas Resource case showing 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.

Figure ES7. Delivered energy consumption for transportation in six cases, 2008-40 (quadrillion Btu)




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.

### 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.

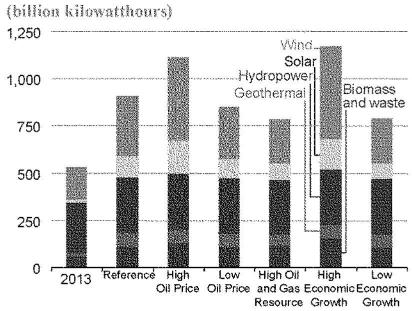
In the High Economic Growth and High Oil Price cases, renewable generation growth exceeds the levels in the Reference case—more than doubling from 2013 to 2040 in both cases (Figure ES8), primarily as a result of increased demand for new generation capacity in the High Economic Growth case and relatively 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)

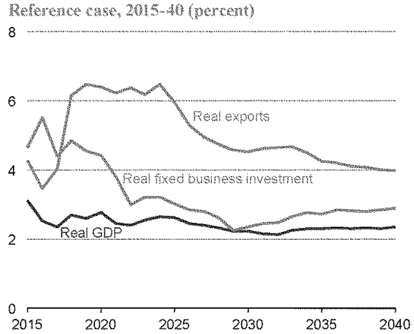
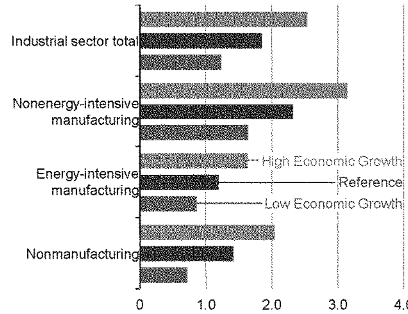



Figure 2. Annual growth rates for industrial output in three cases, 2013-40 (percent per year)




[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)

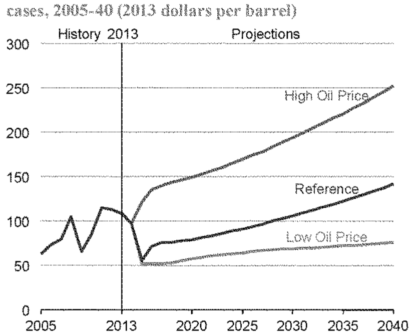



Figure 4. Motor gasoline prices in three cases, 2005-40 (2013 dollars per gallon)

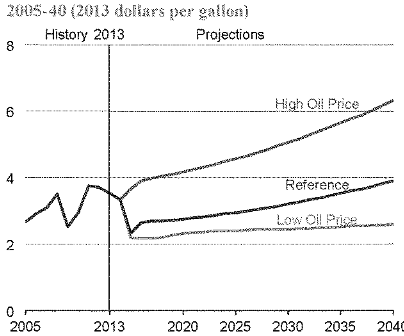
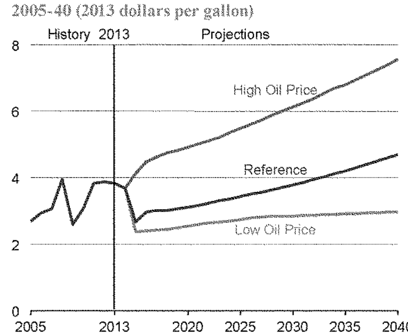



Figure 5. Distillate fuel oil prices in three cases, 2005-40 (2013 dollars per gallon)



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.

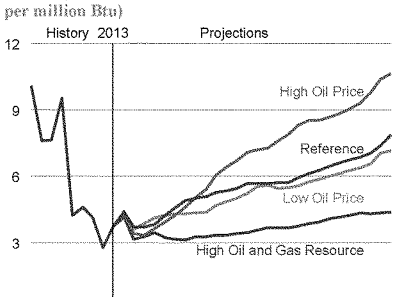
The efficiency and greenhouse gas (GHG) standard for heavy-duty vehicles, which typically consume distillate fuel, rises by about 16% through 2040, remaining below 8 mpg in all AEO2015 cases. Unlike the case for LDVs, the higher VMT in the Low Oil Price case more than offsets the increase in vehicle 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.

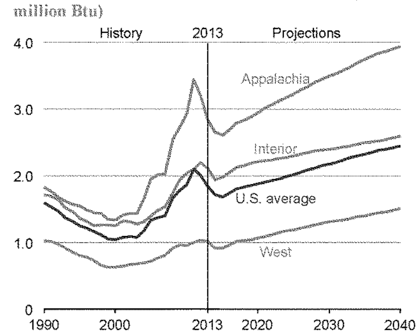
## Coal

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)**

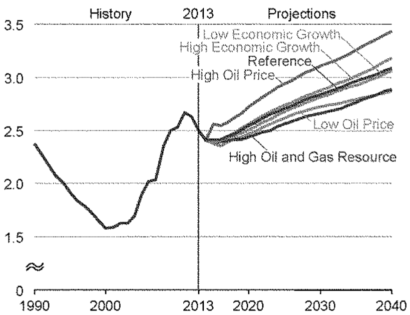
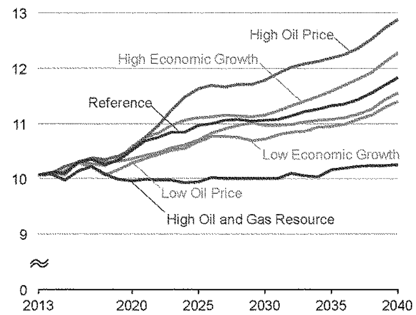



**Figure 9. Average retail electricity prices in six cases, 2013-40 (2013 cents per kilowatthour)**



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.

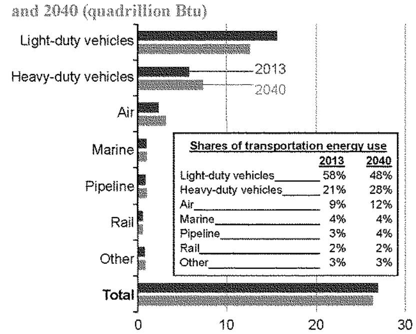
Passenger vehicles fueled exclusively by motor gasoline for all motive and accessory power, excluding any hybridization and flex-fuel capabilities, accounted for 83% of new sales in 2013. In the AEO2015 Reference case, gasoline-only vehicles, excluding hybridization or flex-fuel capabilities, still represent 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.

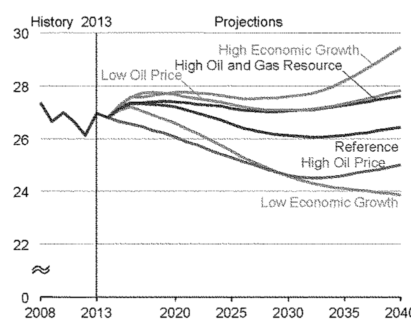
The largest differences from the Reference case level of HDV energy consumption in 2040 are in the High and Low Economic Growth cases (9.4 quadrillion Btu and 6.3 quadrillion Btu, respectively), as a result of their higher and lower projections for travel demand, respectively. Notably, the use of natural 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)

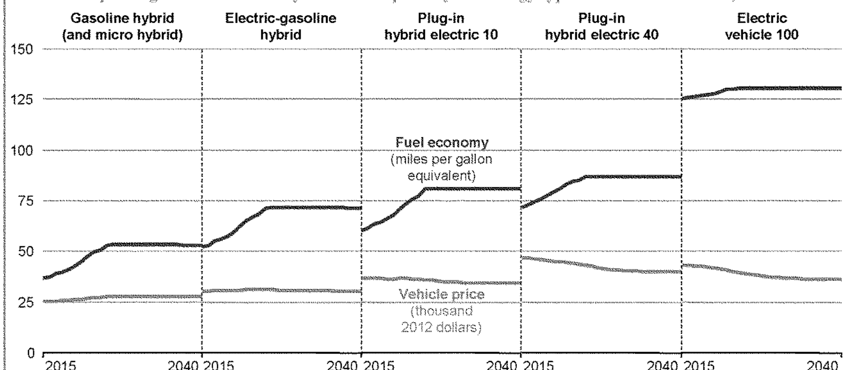



[19]Vocational vehicles include a diverse group of heavy-duty trucks, such as box/delivery trucks, refuse haulers, dump trucks, etc.

**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)**

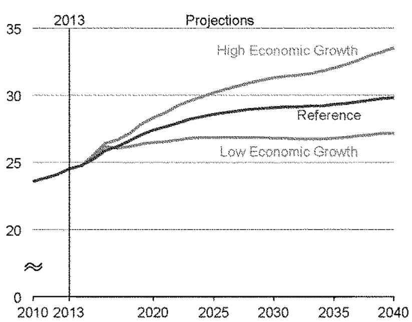
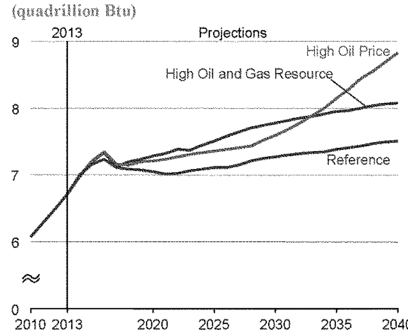



**Figure 13. Industrial sector natural gas consumption for heat and power in three cases, 2010-40 (quadrillion Btu)**



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)

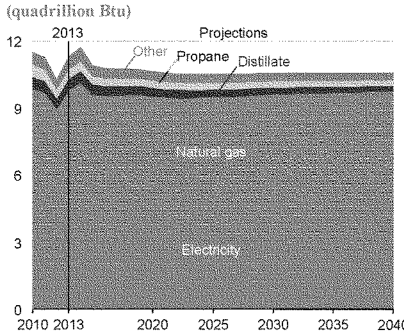
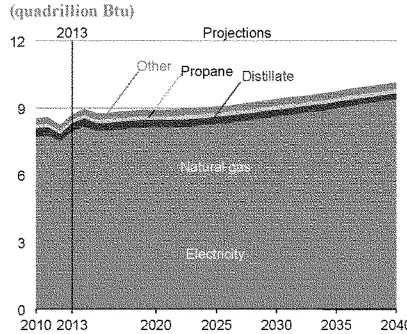



Figure 15. Commercial sector delivered energy consumption by fuel in the Reference case, 2010-40 (quadrillion Btu)




[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)

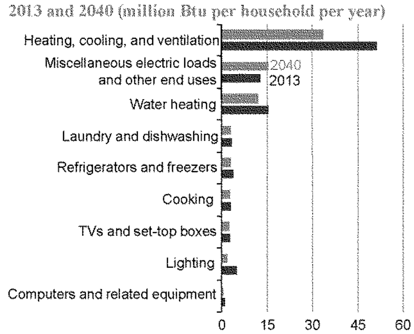
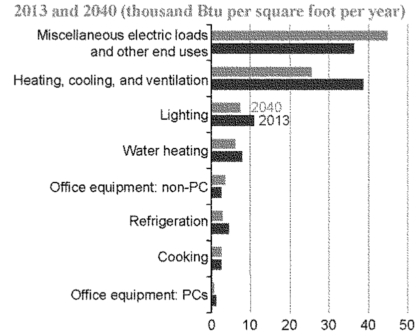



Figure 17. Commercial sector delivered energy intensity for selected end uses in the Reference case, 2013 and 2040 (thousand Btu per square foot per year)

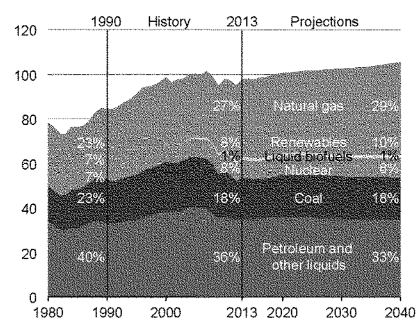



## Energy consumption by primary fuel

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.

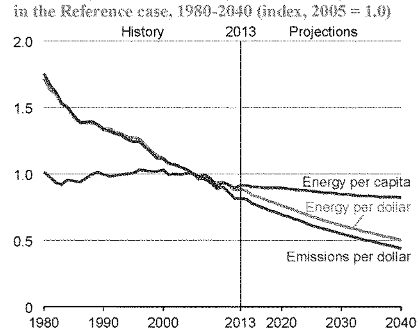
Uncertainty about economic growth results in the widest variation in the projections for total primary energy consumption in 2040, ranging from 98.0 quadrillion Btu in the Low Economic Growth case (1.8% average annual growth in real GDP measured in 2009 dollars) to 116.2 quadrillion Btu in the High Economic 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)**



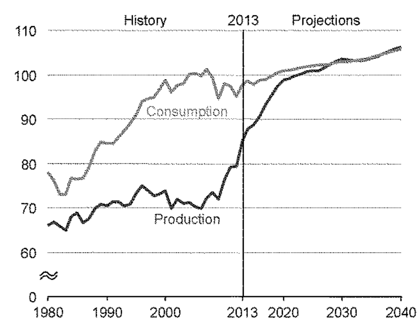

Macroeconomic growth has the largest impact on energy intensity among the AEO2015 alternative cases. Real GDP grows by an average of 1.8%/year from 2013 to 2040 in the Low Economic Growth case, and population grows by an average of 0.6%/year over the same period. Even though energy use increases only 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)

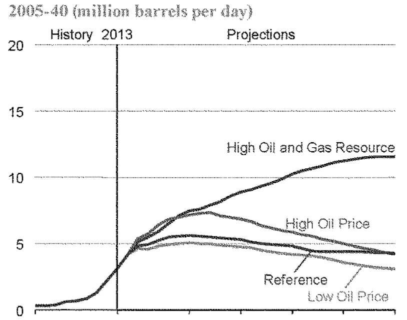
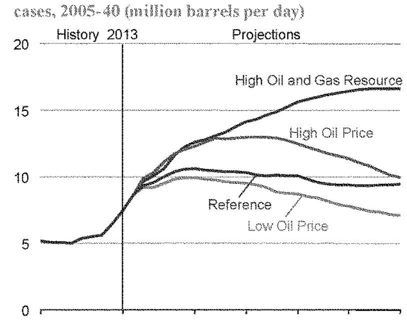



Figure 22. U.S. total crude oil production in four cases, 2005-40 (million barrels per day)




[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.

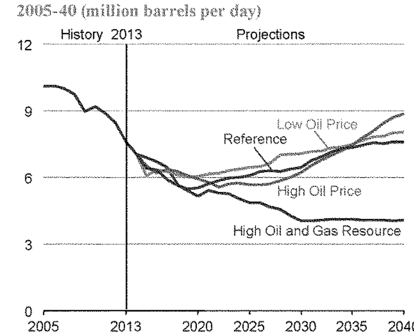
Production of petroleum products at U.S. refineries depends largely on the cost of crude oil, domestic demand, and the absorption of petroleum product exports in foreign markets. U.S. refinery production of gasoline blending components declines in the Reference and Low Oil Price cases but increases in 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)

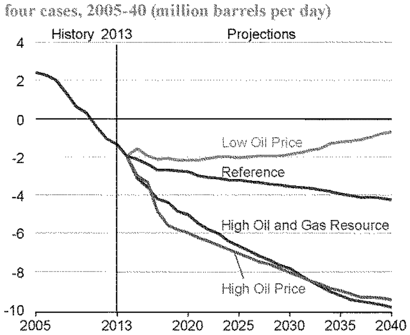
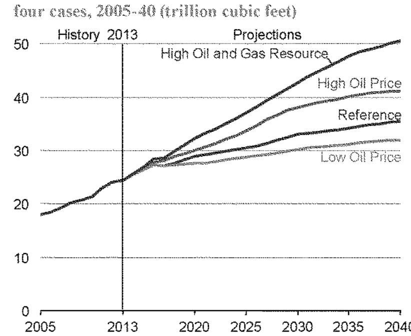



Figure 25. U.S. total dry natural gas production in four cases, 2005-40 (trillion cubic feet)




[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)

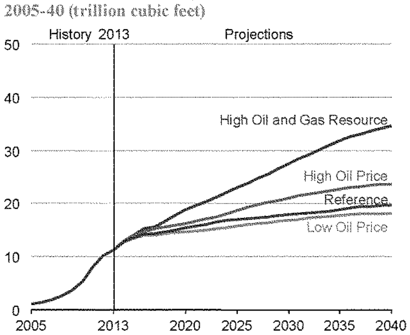
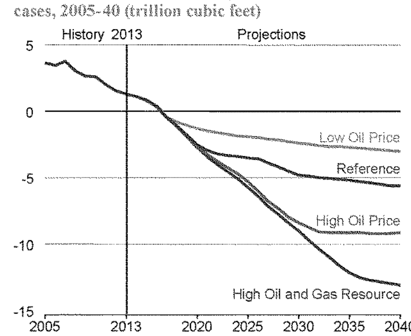



Figure 27. U.S. total natural gas net imports in four cases, 2005-40 (trillion cubic feet)



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.

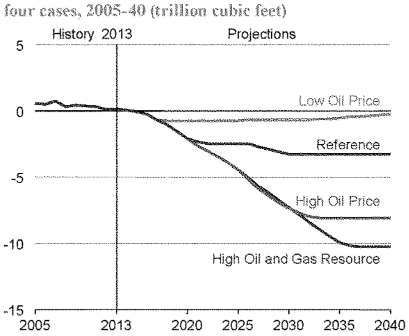
In the High Oil Price case, U.S. LNG exports total 8.1 Tcf in 2040, or 142% more than in the Reference case. As a result, U.S. net natural gas exports total 9.1 Tcf in 2040 in the High Oil Price case, or 63% more than in the Reference case. In the Low World Oil Price case, LNG net exports never surpass 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)

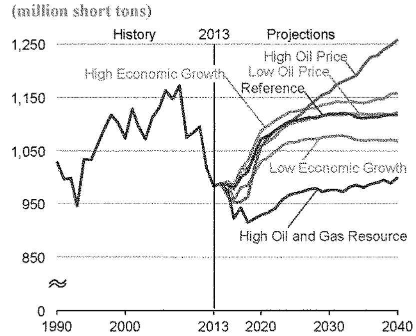
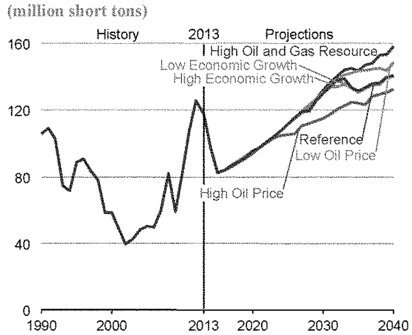



Figure 30. U.S. coal exports in six cases, 1990-2040 (million short tons)



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)

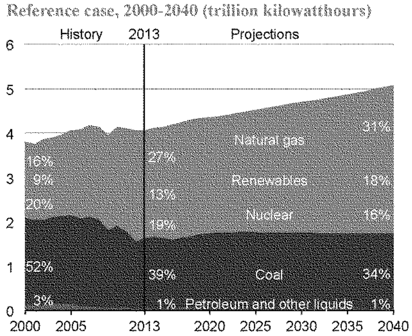
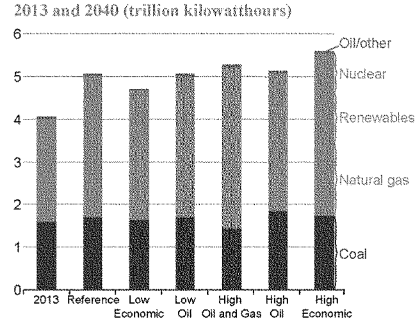



Figure 32. Electricity generation by fuel in six cases, 2013 and 2040 (trillion kilowatthours)




[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)**

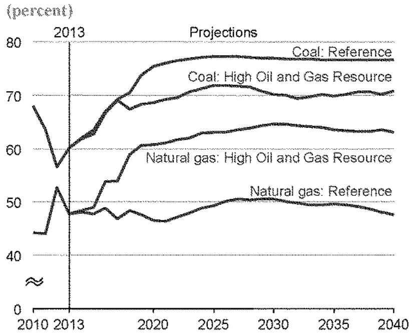



**Figure 34. Renewable electricity generation by fuel type in the Reference case, 2000-2040 (billion kilowatthours)**

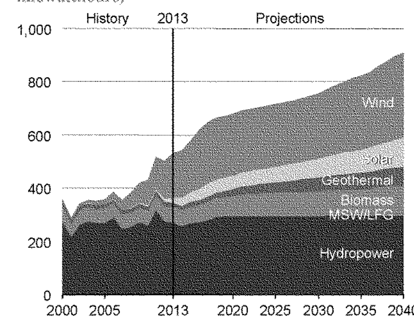
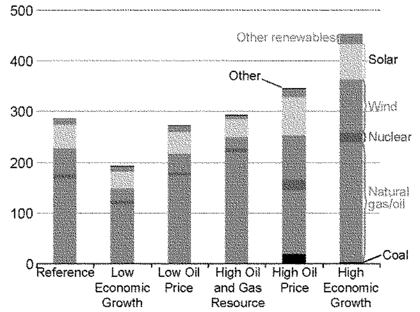


**Figure 35. Cumulative additions to electricity generation capacity by fuel in six cases, 2013-40 (gigawatts)**




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.

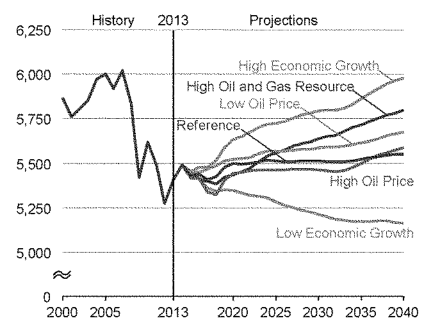
High construction costs for nuclear plants limit their competitiveness to meet new demand in the Reference case. In the near term, 5.5 GW of planned additions are put into place by 2020, offset by 3.2 GW of retirements over the same period. After 2025, 3.5 GW of additional nuclear capacity is built, 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

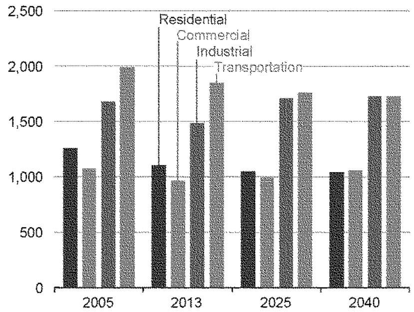
**Figure 36. Energy-related carbon dioxide emissions in six cases, 2000-2040 (million metric tons)**



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 | GW | Gigawatt(s) |
| AEO2015 | Annual Energy Outlook 2015 | HDV | Heavy-duty vehicle |
| API | American Petroleum Institute | HGL | Hydrocarbon gas liquids |
| bbl | Barrels | kWh | Kilowatthour(s) |
| bbl/d | Barrels per day | LDV | Light-duty vehicle |
| Brent | North Sea Brent | LNG | Liquefied natural gas |
| Btu | British thermal unit(s) | MARPOL | Marine pollution |
| CAFE | Corporate average fuel economy | MATS | Mercury and Air Toxics Standards |
| CAIR | Clean Air Interstate Rule | Mcf | Thousand cubic feet |
| CHP | Combined heat and power | MELs | Miscellaneous electric loads |
| CO2 | Carbon dioxide | mpg | Miles per gallon |
| CPI | Consumer price index | mt | Metric ton(s) |
| CSAPR | Cross-State Air Pollution Rule | NGPL | Natural gas plant liquids |
| CTL | Coal-to-liquids | OECD | Organization for Economic Cooperation and Development |
| E85 | Motor fuel containing up to 85% ethanol | OPEC | Organization of the Petroleum Exporting Countries |
| EIA | U.S. Energy Information Administration | PADD | Petroleum Administration for Defense District |
| EOR | Enhanced oil recovery | PV | Photovoltaic |
| EPA | U.S. Environmental Protection Agency | RFS | Renewable fuel standard |
| EUR | Estimated ultimate recovery | Tcf | Trillion cubic feet |
| GDP | Gross domestic product | U.S. | United States |
| GTL | Gas-to-liquids | VMT | Vehicle miles traveled |

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## Figure and table sources

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**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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**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[18] | 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 | | | | | | | Annual growth 2013-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2012 | 2013 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **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 2012 | 2013 | 2020 | 2025 | 2030 | 2035 | 2040 | Annual growth 2013-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| **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[5] | 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 | | | | | | | Annual growth 2013-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2012 | 2013 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **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 | | | | | | | Annual growth 2013-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2012 | 2013 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **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 | | | | | | | Annual growth 2013-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2012 | 2013 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **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 | 0.28 | 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 | 83.8 | 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 2012 | 2013 | 2020 | 2025 | 2030 | 2035 | 2040 | Annual growth 2013-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| **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 2012 | 2013 | 2020 | 2025 | 2030 | 2035 | 2040 | Annual growth 2013-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| **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 | | | | | | | Annual growth 2013-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2012 | 2013 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **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 2005 chain-weighted dollars, unless otherwise noted)

| Indicators | Reference case | | | | | | | Annual growth 2013-2040 (percent) |
|---|---|---|---|---|---|---|---|---|
| | 2012 | 2013 | 2020 | 2025 | 2030 | 2035 | 2040 | |
| **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.

## 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 | | | 2030 | | | 2040 | | |
| | | Low economic growth | Reference | High economic growth | Low economic growth | Reference | High economic growth | Low economic growth | Reference | 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 2005 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 | 14,388 | 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.

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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** | **116.5** | **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 Low oil price | 2020 Reference | 2020 High oil price | 2030 Low oil price | 2030 Reference | 2030 High oil price | 2040 Low oil price | 2040 Reference | 2040 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** | **34.95** |
| 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[16] | 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.
[15]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 | 2020 Reference | 2020 High oil and gas resource | 2030 Reference | 2030 High oil and gas resource | 2040 Reference | 2040 High oil and gas resource |
|---|---|---|---|---|---|---|---|
| | | Projections | | | | | |
| **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**

| Energy and economic factors | 2012 | 2013 | 2025 AEO2015 | 2025 AEO2014 | 2040 AEO2015 | 2040 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)**

| Energy and economic factors | 2012 | 2013 | 2025 AEO2015 | 2025 AEO2014 | 2040 AEO2015 | 2040 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.

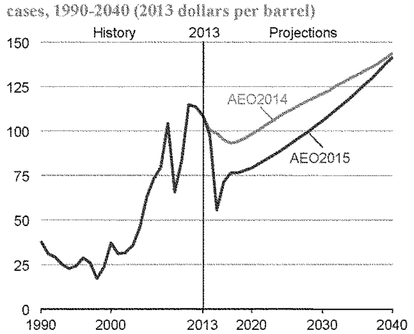
## Comparison of AEO2015 and AEO2014 Reference cases

### 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

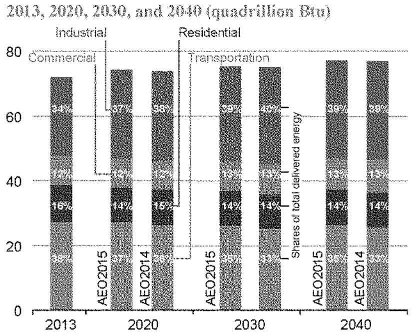
Delivered energy consumption in the transportation sector in the AEO2015 Reference case is higher than in AEO2014 (26.5 quadrillion Btu in 2040 compared with 25.5 quadrillion Btu), with energy consumption for nearly all transportation modes higher in AEO2015 throughout most of the projection, because 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**

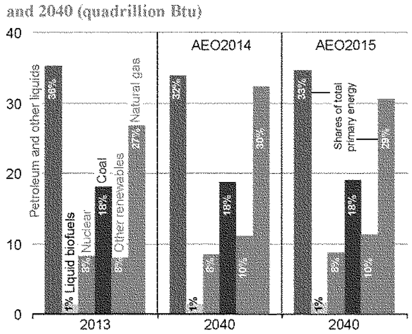
Commercial sector delivered energy consumption grows from 8.7 quadrillion Btu in 2013 to 10.1 quadrillion Btu in 2040 in the AEO2015 Reference case, similar to the AEO2014 Reference case, despite higher consumption in the near term. Commercial electricity consumption increases by 0.8%/year from 2013 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)

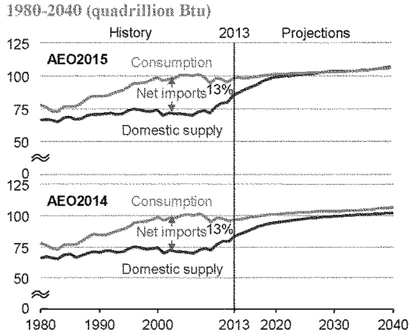
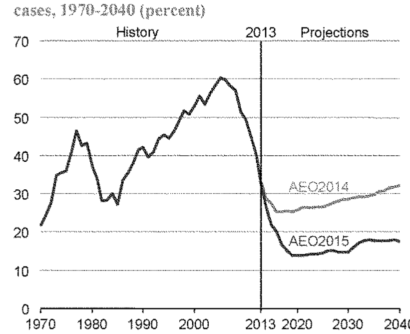



Figure E5. Share of U.S. liquid fuels supply from net imports in the AEO2015 and AEO2014 Reference cases, 1970-2040 (percent)




[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.

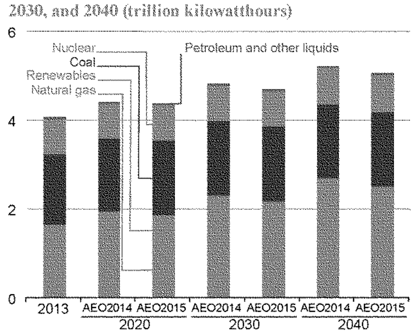
Electricity generation from natural gas grows at a slower rate in the AEO2015 Reference case than in the AEO2014 Reference case because of lower growth in overall electricity demand, higher natural gas prices in the midterm, fewer nuclear retirements, and more renewable capacity additions leading to 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 CO2 emissions

Total U.S. energy-related CO2 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 CO2 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 CO2. 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 CO2 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 CO2 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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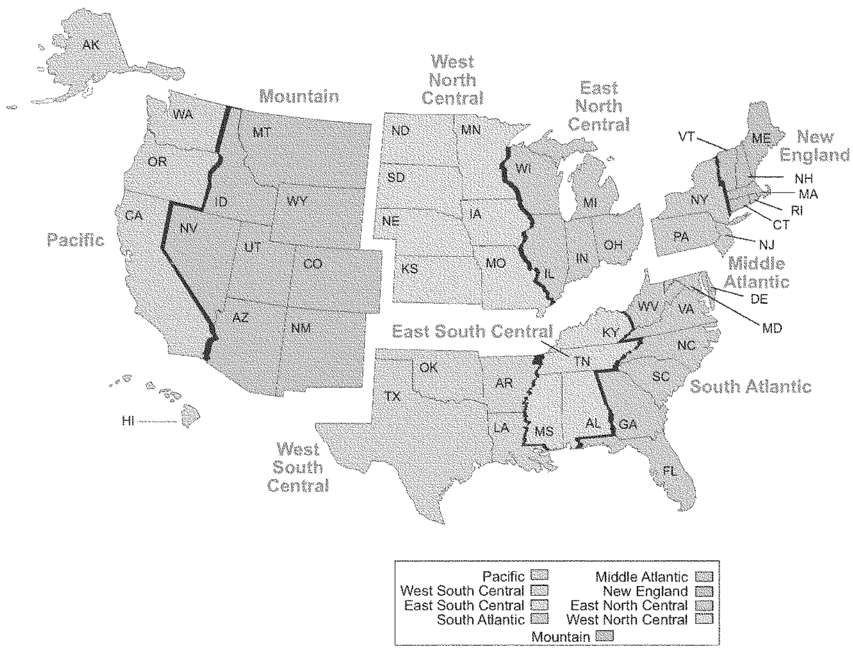
Appendix F

# 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**

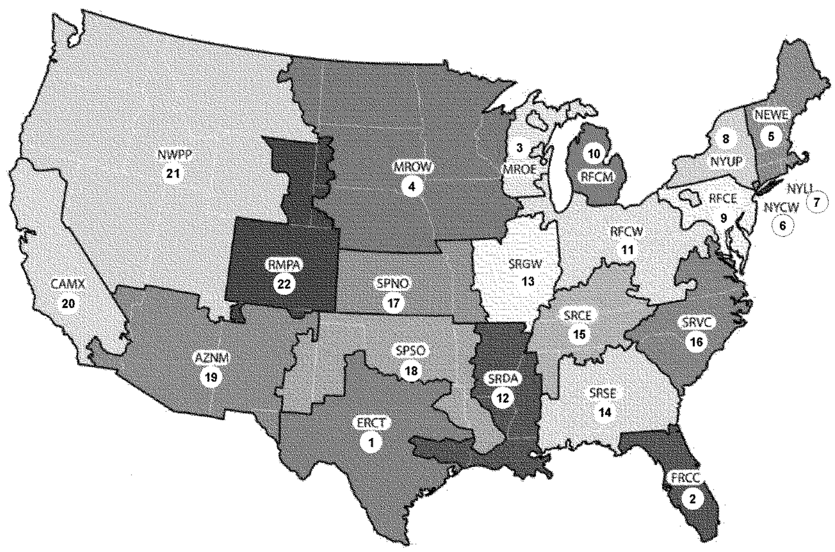
Arizona
Colorado
Idaho
Montana
Nevada
New Mexico
Utah
Wyoming

**Division 9**
**Pacific**

Alaska
California
Hawaii
Oregon
Washington

Source: U.S. Energy Information Administration, Office of Energy Analysis.

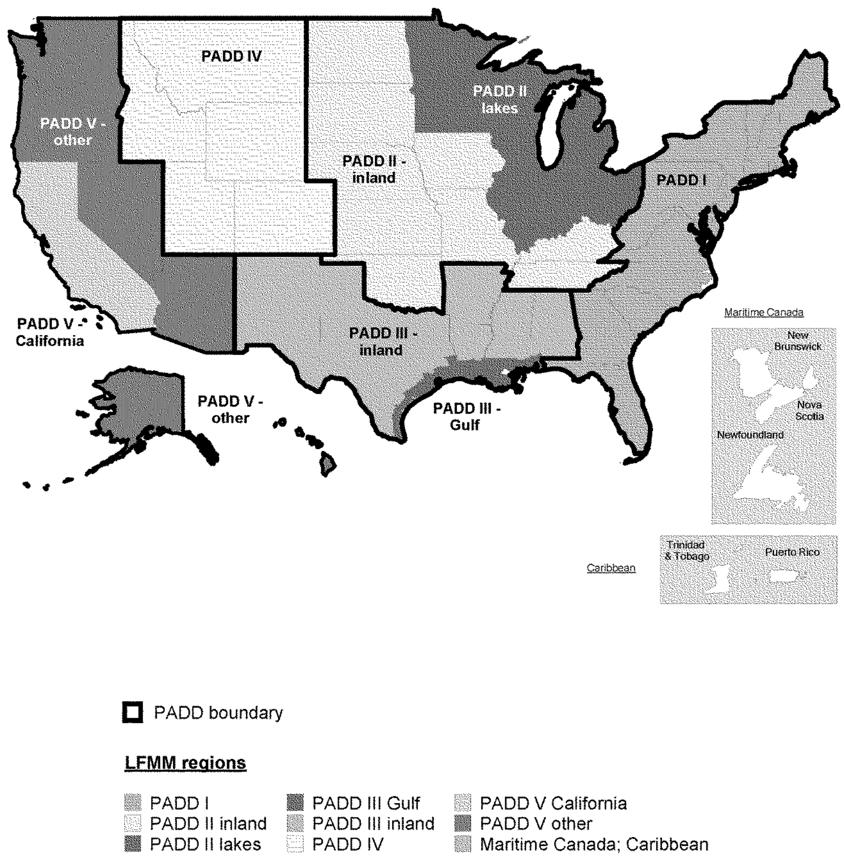
Figure F2. Electricity market module regions




| | | | | | |
|---|---|---|---|---|---|
| 1. | ERCT | TRE All | 12. | SRDA | SERC Delta |
| 2. | FRCC | FRCC All | 13. | SRGW | SERC Gateway |
| 3. | MROE | MRO East | 14. | SRSE | SERC Southeastern |
| 4. | MROW | MRO West | 15. | SRCE | SERC Central |
| 5. | NEWE | NPCC New England | 16. | SRVC | SERC VACAR |
| 6. | NYCW | NPCC NYC/Westchester | 17. | SPNO | SPP North |
| 7. | NYLI | NPCC Long Island | 18. | SPSO | SPP South |
| 8. | NYUP | NPCC Upstate NY | 19. | AZNM | WECC Southwest |
| 9. | RFCE | RFC East | 20. | CAMX | WECC California |
| 10. | RFCM | RFC Michigan | 21. | NWPP | WECC Northwest |
| 11. | RFCW | RFC West | 22. | RMPA | WECC Rockies |

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F3. Liquid fuels market module regions

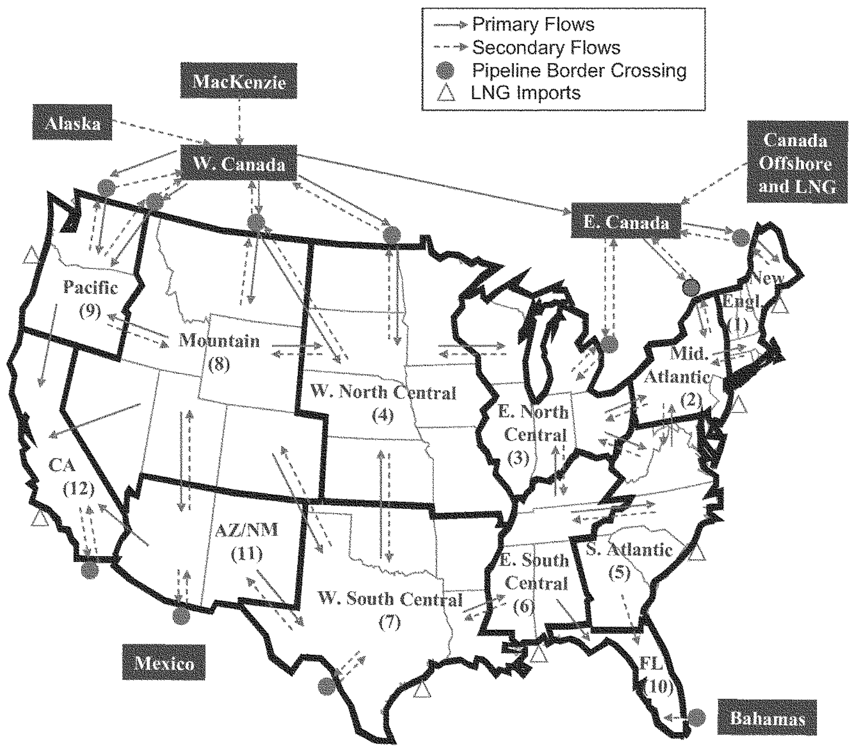



Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F4. Oil and gas supply model regions

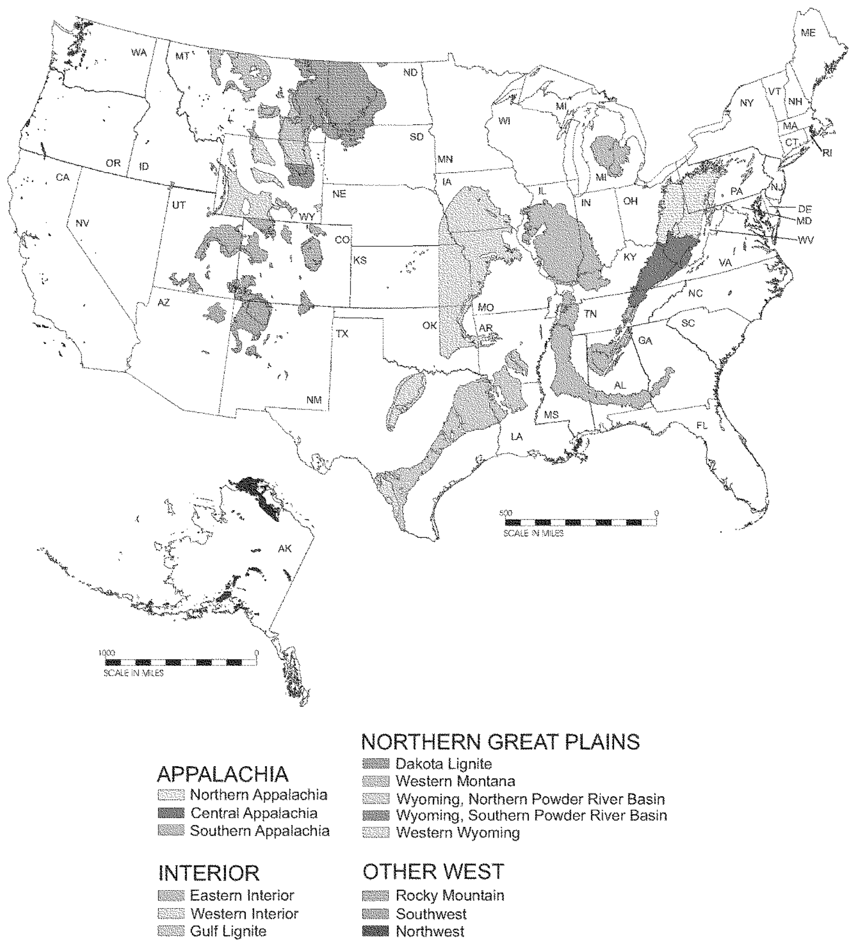

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F5. Natural gas transmission and distribution model regions



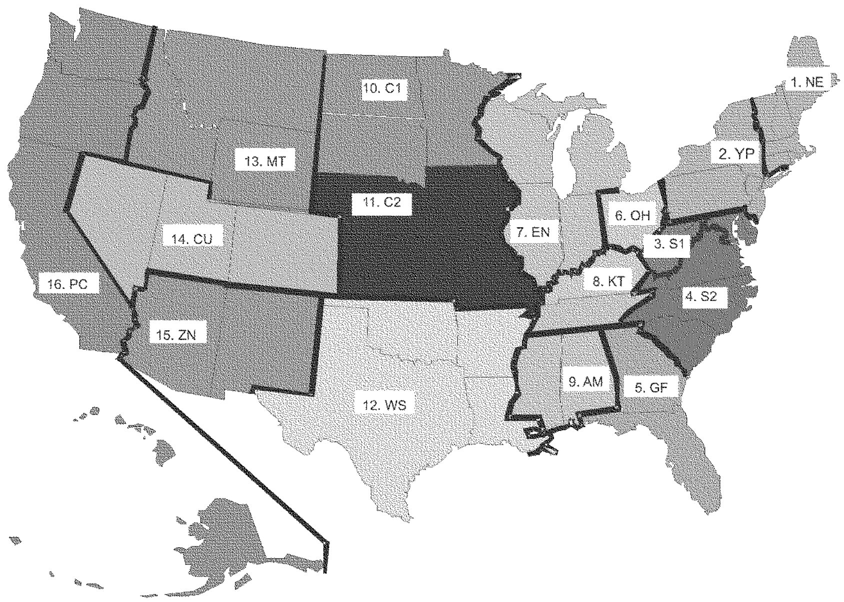

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F6. Coal supply regions




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.

Appendix G

# 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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