# Appendix O:

# Senate Bill 310 of the 130th Ohio General Assembly

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**(130th General Assembly)**
**(Substitute Senate Bill Number 310)**

# AN ACT

**To amend sections 3706.25, 4928.01, 4928.20, 4928.53, 4928.64, 4928.65, and 4928.66, to amend, for the purpose of adopting a new section number as indicated in parentheses, section 4928.65 (4928.645), and to enact new section 4928.65 and sections 4928.112, 4928.641, 4928.643, 4928.644, 4928.662, 4928.6610, 4928.6611, 4928.6612, 4928.6613, 4928.6614, 4928.6615, and 4928.6616 of the Revised Code to make changes to the renewable energy, energy efficiency, and peak demand reduction requirements, to prohibit the imposition of a waiting period before enrolling an eligible customer in the percentage of income payment plan, and to create a study committee.**

***Be it enacted by the General Assembly of the State of Ohio:***

**SECTION 1.** That sections 3706.25, 4928.01, 4928.20, 4928.53, 4928.64, 4928.65, and 4928.66 be amended, section 4928.65 (4928.645) be amended for the purpose of adopting a new section number as indicated in parentheses, and new section 4928.65 and sections 4928.112, 4928.641, 4928.643, 4928.644, 4928.662, 4928.6610, 4928.6611, 4928.6612, 4928.6613, 4928.6614, 4928.6615, and 4928.6616 of the Revised Code be enacted to read as follows:

**Sec. 3706.25.** As used in sections 3706.25 to 3706.30 of the Revised Code:

(A) "Advanced energy project" means any technologies, products, activities, or management practices or strategies that facilitate the generation or use of electricity or energy and that reduce or support the reduction of energy consumption or support the production of clean, renewable energy for industrial, distribution, commercial, institutional, governmental, research, not-for-profit, or residential energy users including, but not limited to, advanced energy resources and renewable energy resources. "Advanced energy project" includes any project described in division (A), (B), or (C) of section 4928.621 of the Revised Code.

(B) "Advanced energy resource" means any of the following:

(1) Any method or any modification or replacement of any property, process, device, structure, or equipment that increases the generation output of an electric generating facility to the extent such efficiency is achieved without additional carbon dioxide emissions by that facility;

(2) Any distributed generation system consisting of customer cogeneration technology, primarily to meet the energy needs of the customer's facilities;

(3) Advanced nuclear energy technology consisting of generation III technology as defined by the nuclear regulatory commission; other, later technology; or significant improvements to existing facilities;

(4) Any fuel cell used in the generation of electricity, including, but not limited to, a proton exchange membrane fuel cell, phosphoric acid fuel cell, molten carbonate fuel cell, or solid oxide fuel cell;

(5) Advanced solid waste or construction and demolition debris conversion technology, including, but not limited to, advanced stoker technology, and advanced fluidized bed gasification technology, that results in measurable greenhouse gas emissions reductions as calculated pursuant to the United States environmental protection agency's waste reduction model (WARM).

(C) "Air contaminant source" has the same meaning as in section 3704.01 of the Revised Code.

(D) "Cogeneration technology" means technology that produces electricity and useful thermal output simultaneously.

(E) "Renewable energy resource" means solar photovoltaic or solar thermal energy, wind energy, power produced by a hydroelectric facility, power produced by a run-of-the-river hydroelectric facility placed in service on or after January 1, 1980, that is located within this state, relies upon the Ohio river, and operates, or is rated to operate, at an aggregate capacity of forty or more megawatts, geothermal energy, fuel derived from solid wastes, as defined in section 3734.01 of the Revised Code, through fractionation, biological decomposition, or other process that does not principally involve combustion, biomass energy, energy produced by cogeneration technology that is placed into service on or before December 31, 2015, and for which more than ninety per cent of the total annual energy input is from combustion of a waste or byproduct gas from an air contaminant source in this state, which source has been in operation since on or before January 1, 1985, provided that the cogeneration technology is a part of a facility located in a county having a population of more than three hundred sixty-five thousand but less than three hundred seventy thousand according to the most recent federal decennial census, biologically derived methane gas, heat captured from a generator of electricity, boiler, or heat exchanger fueled by biologically derived methane gas, or energy derived from nontreated by-products of the pulping process or wood manufacturing process, including bark, wood chips, sawdust, and lignin in spent pulping liquors. "Renewable energy resource" includes, but is not limited to, any fuel cell used in the generation of electricity, including, but not limited to, a proton exchange membrane fuel cell, phosphoric acid fuel cell, molten carbonate fuel cell, or solid oxide fuel cell; wind turbine located in the state's territorial waters of Lake Erie; methane gas emitted from an abandoned coal mine; storage facility that will promote the better utilization of a renewable energy resource that primarily generates off peak; or distributed generation system used by a customer to generate electricity from any such energy. As used in this division, "hydroelectric facility" means a hydroelectric generating facility that is located at a dam on a river, or on any water discharged to a river, that is within or bordering this state or within or bordering an adjoining state and meets all of the following standards:

(1) The facility provides for river flows that are not detrimental for fish, wildlife, and water quality, including seasonal flow fluctuations as defined by the applicable licensing agency for the facility.

(2) The facility demonstrates that it complies with the water quality standards of this state, which compliance may consist of certification under Section 401 of the "Clean Water Act of 1977," 91 Stat. 1598, 1599, 33 U.S.C. 1341, and demonstrates that it has not contributed to a finding by this state that the river has impaired water quality under Section 303(d) of the "Clean Water Act of 1977," 114 Stat. 870, 33 U.S.C. 1313.

(3) The facility complies with mandatory prescriptions regarding fish passage as required by the federal energy regulatory commission license issued for the project, regarding fish protection for riverine, anadromous, and catadromous fish.

(4) The facility complies with the recommendations of the Ohio environmental protection agency and with the terms of its federal energy regulatory commission license regarding watershed protection, mitigation, or enhancement, to the extent of each agency's respective jurisdiction over the facility.

(5) The facility complies with provisions of the "Endangered Species Act of 1973," 87 Stat. 884, 16 U.S.C. 1531 to 1544, as amended.

(6) The facility does not harm cultural resources of the area. This can be shown through compliance with the terms of its federal energy regulatory commission license or, if the facility is not regulated by that commission, through development of a plan approved by the Ohio historic

preservation office, to the extent it has jurisdiction over the facility.

(7) The facility complies with the terms of its federal energy regulatory commission license or exemption that are related to recreational access, accommodation, and facilities or, if the facility is not regulated by that commission, the facility complies with similar requirements as are recommended by resource agencies, to the extent they have jurisdiction over the facility; and the facility provides access to water to the public without fee or charge.

(8) The facility is not recommended for removal by any federal agency or agency of any state, to the extent the particular agency has jurisdiction over the facility.

**Sec. 4928.01.** (A) As used in this chapter:

(1) "Ancillary service" means any function necessary to the provision of electric transmission or distribution service to a retail customer and includes, but is not limited to, scheduling, system control, and dispatch services; reactive supply from generation resources and voltage control service; reactive supply from transmission resources service; regulation service; frequency response service; energy imbalance service; operating reserve-spinning reserve service; operating reserve-supplemental reserve service; load following; back-up supply service; real-power loss replacement service; dynamic scheduling; system black start capability; and network stability service.

(2) "Billing and collection agent" means a fully independent agent, not affiliated with or otherwise controlled by an electric utility, electric services company, electric cooperative, or governmental aggregator subject to certification under section 4928.08 of the Revised Code, to the extent that the agent is under contract with such utility, company, cooperative, or aggregator solely to provide billing and collection for retail electric service on behalf of the utility company, cooperative, or aggregator.

(3) "Certified territory" means the certified territory established for an electric supplier under sections 4933.81 to 4933.90 of the Revised Code.

(4) "Competitive retail electric service" means a component of retail electric service that is competitive as provided under division (B) of this section.

(5) "Electric cooperative" means a not-for-profit electric light company that both is or has been financed in whole or in part under the "Rural Electrification Act of 1936," 49 Stat. 1363, 7 U.S.C. 901, and owns or operates facilities in this state to generate, transmit, or distribute electricity, or a not-for-profit successor of such company.

(6) "Electric distribution utility" means an electric utility that supplies at least retail electric distribution service.

(7) "Electric light company" has the same meaning as in section 4905.03 of the Revised Code and includes an electric services company, but excludes any self-generator to the extent that it consumes electricity it so produces, sells that electricity for resale, or obtains electricity from a generating facility it hosts on its premises.

(8) "Electric load center" has the same meaning as in section 4933.81 of the Revised Code.

(9) "Electric services company" means an electric light company that is engaged on a for-profit or not-for-profit basis in the business of supplying or arranging for the supply of only a competitive retail electric service in this state. "Electric services company" includes a power marketer, power broker, aggregator, or independent power producer but excludes an electric cooperative, municipal electric utility, governmental aggregator, or billing and collection agent.

(10) "Electric supplier" has the same meaning as in section 4933.81 of the Revised Code.

(11) "Electric utility" means an electric light company that has a certified territory and is engaged on a for-profit basis either in the business of supplying a noncompetitive retail electric service in this state or in the businesses of supplying both a noncompetitive and a competitive retail electric service in this state. "Electric utility" excludes a municipal electric utility or a billing and collection agent.

(12) "Firm electric service" means electric service other than nonfirm electric service.

(13) "Governmental aggregator" means a legislative authority of a municipal corporation, a board of township trustees, or a board of county commissioners acting as an aggregator for the provision of a competitive retail electric service under authority conferred under section 4928.20 of the Revised Code.

(14) A person acts "knowingly," regardless of the person's purpose, when the person is aware that the person's conduct will probably cause a certain result or will probably be of a certain nature. A person has knowledge of circumstances when the person is aware that such circumstances probably exist.

(15) "Level of funding for low-income customer energy efficiency programs provided through electric utility rates" means the level of funds specifically included in an electric utility's rates on October 5, 1999, pursuant to an order of the public utilities commission issued under Chapter 4905. or 4909. of the Revised Code and in effect on October 4, 1999, for the purpose of improving the energy efficiency of housing for the utility's low-income customers. The term excludes the level of any such funds committed to a specific nonprofit organization or organizations pursuant to a stipulation or contract.

(16) "Low-income customer assistance programs" means the percentage of income payment plan program, the home energy assistance program, the home weatherization assistance program, and the targeted energy efficiency and weatherization program.

(17) "Market development period" for an electric utility means the period of time beginning on the starting date of competitive retail electric service and ending on the applicable date for that utility as specified in section 4928.40 of the Revised Code, irrespective of whether the utility applies to receive transition revenues under this chapter.

(18) "Market power" means the ability to impose on customers a sustained price for a product or service above the price that would prevail in a competitive market.

(19) "Mercantile customer" means a commercial or industrial customer if the electricity consumed is for nonresidential use and the customer consumes more than seven hundred thousand kilowatt hours per year or is part of a national account involving multiple facilities in one or more states.

(20) "Municipal electric utility" means a municipal corporation that owns or operates facilities to generate, transmit, or distribute electricity.

(21) "Noncompetitive retail electric service" means a component of retail electric service that is noncompetitive as provided under division (B) of this section.

(22) "Nonfirm electric service" means electric service provided pursuant to a schedule filed under section 4905.30 of the Revised Code or pursuant to an arrangement under section 4905.31 of the Revised Code, which schedule or arrangement includes conditions that may require the customer to curtail or interrupt electric usage during nonemergency circumstances upon notification by an electric utility.

(23) "Percentage of income payment plan arrears" means funds eligible for collection through the percentage of income payment plan rider, but uncollected as of July 1, 2000.

(24) "Person" has the same meaning as in section 1.59 of the Revised Code.

(25) "Advanced energy project" means any technologies, products, activities, or management practices or strategies that facilitate the generation or use of electricity or energy and that reduce or support the reduction of energy consumption or support the production of clean, renewable energy for industrial, distribution, commercial, institutional, governmental, research, not-for-profit, or residential energy users, including, but not limited to, advanced energy resources and renewable energy resources. "Advanced energy project" also includes any project described in division (A), (B), or (C) of section 4928.621 of the Revised Code.

(26) "Regulatory assets" means the unamortized net regulatory assets that are capitalized or deferred on the regulatory books of the electric utility, pursuant to an order or practice of the public utilities commission or pursuant to generally accepted accounting principles as a result of a prior commission rate-making decision, and that would otherwise have been charged to expense as incurred or would not have been capitalized or otherwise deferred for future regulatory consideration absent commission action. "Regulatory assets" includes, but is not limited to, all deferred demand-side management costs; all deferred percentage of income payment plan arrears; post-in-service capitalized charges and assets recognized in connection with statement of financial accounting standards no. 109 (receivables from customers for income taxes); future nuclear decommissioning costs and fuel disposal costs as those costs have been determined by the commission in the electric utility's most recent rate or accounting application proceeding addressing such costs; the undepreciated costs of safety and radiation control equipment on nuclear generating plants owned or leased by an electric utility; and fuel costs currently deferred pursuant to the terms of one or more settlement agreements approved by the commission.

(27) "Retail electric service" means any service involved in supplying or arranging for the supply of electricity to ultimate consumers in this state, from the point of generation to the point of consumption. For the purposes of this chapter, retail electric service includes one or more of the following

"service components": generation service, aggregation service, power marketing service, power brokerage service, transmission service, distribution service, ancillary service, metering service, and billing and collection service.

(28) "Starting date of competitive retail electric service" means January 1, 2001.

(29) "Customer-generator" means a user of a net metering system.

(30) "Net metering" means measuring the difference in an applicable billing period between the electricity supplied by an electric service provider and the electricity generated by a customer-generator that is fed back to the electric service provider.

(31) "Net metering system" means a facility for the production of electrical energy that does all of the following:

(a) Uses as its fuel either solar, wind, biomass, landfill gas, or hydropower, or uses a microturbine or a fuel cell;

(b) Is located on a customer-generator's premises;

(c) Operates in parallel with the electric utility's transmission and distribution facilities;

(d) Is intended primarily to offset part or all of the customer-generator's requirements for electricity.

(32) "Self-generator" means an entity in this state that owns or hosts on its premises an electric generation facility that produces electricity primarily for the owner's consumption and that may provide any such excess electricity to another entity, whether the facility is installed or operated by the owner or by an agent under a contract.

(33) "Rate plan" means the standard service offer in effect on the effective date of the amendment of this section by S.B. 221 of the 127th general assembly, July 31, 2008.

(34) "Advanced energy resource" means any of the following:

(a) Any method or any modification or replacement of any property, process, device, structure, or equipment that increases the generation output of an electric generating facility to the extent such efficiency is achieved without additional carbon dioxide emissions by that facility;

(b) Any distributed generation system consisting of customer cogeneration technology;

(c) Clean coal technology that includes a carbon-based product that is chemically altered before combustion to demonstrate a reduction, as expressed as ash, in emissions of nitrous oxide, mercury, arsenic, chlorine, sulfur dioxide, or sulfur trioxide in accordance with the American society of testing and materials standard D1757A or a reduction of metal oxide emissions in accordance with standard D5142 of that society, or clean coal technology that includes the design capability to control or prevent the emission of carbon dioxide, which design capability the commission shall adopt by rule and shall be based on economically feasible best available technology or, in the absence of a determined best available technology, shall be of the highest level of economically feasible design capability for which there exists generally accepted scientific opinion;

(d) Advanced nuclear energy technology consisting of generation III technology as defined by the nuclear regulatory commission; other, later technology; or significant improvements to existing facilities;

(e) Any fuel cell used in the generation of electricity, including, but not limited to, a proton exchange membrane fuel cell, phosphoric acid fuel cell, molten carbonate fuel cell, or solid oxide fuel cell;

(f) Advanced solid waste or construction and demolition debris conversion technology, including, but not limited to, advanced stoker technology, and advanced fluidized bed gasification technology, that results in measurable greenhouse gas emissions reductions as calculated pursuant to the United States environmental protection agency's waste reduction model (WARM);

(g) Demand-side management and any energy efficiency improvement;

(h) Any new, retrofitted, refueled, or repowered generating facility located in Ohio, including a simple or combined-cycle natural gas generating facility or a generating facility that uses biomass, coal, modular nuclear, or any other fuel as its input;

(i) Any uprated capacity of an existing electric generating facility if the uprated capacity results from the deployment of advanced technology.

"Advanced energy resource" does not include a waste energy recovery system that is, or has been, included in an energy efficiency program of an electric distribution utility pursuant to requirements under section 4928.66 of the Revised Code.

(35) "Air contaminant source" has the same meaning as in section 3704.01 of the Revised Code.

(36) "Cogeneration technology" means technology that produces electricity and useful thermal output simultaneously.

(37)(a) "Renewable energy resource" means any of the following:

(i) Solar photovoltaic or solar thermal energy;

(ii) Wind energy;

(iii) Power produced by a hydroelectric facility;

(iv) Power produced by a run-of-the-river hydroelectric facility placed in service on or after January 1, 1980, that is located within this state, relies upon the Ohio river, and operates, or is rated to operate, at an aggregate capacity of forty or more megawatts;

(v) Geothermal energy;

~~(v)~~(vi) Fuel derived from solid wastes, as defined in section 3734.01 of the Revised Code, through fractionation, biological decomposition, or other process that does not principally involve combustion;

~~(vi)~~(vii) Biomass energy;

~~(vii)~~(viii) Energy produced by cogeneration technology that is placed into service on or before December 31, 2015, and for which more than ninety per cent of the total annual energy input is from combustion of a waste or byproduct gas from an air contaminant source in this state, which source has been in operation since on or before January 1, 1985, provided that the cogeneration technology is a part of a facility located in a county having a population of more than three hundred sixty-five thousand but less than three hundred seventy thousand according to the most recent federal decennial census;

~~(viii)~~(ix) Biologically derived methane gas;

~~(ix)~~(x) Heat captured from a generator of electricity, boiler, or heat exchanger fueled by biologically derived methane gas;

(xi) Energy derived from nontreated by-products of the pulping process or wood manufacturing process, including bark, wood chips, sawdust, and lignin in spent pulping liquors.

"Renewable energy resource" includes, but is not limited to, any fuel cell used in the generation of electricity, including, but not limited to, a proton exchange membrane fuel cell, phosphoric acid fuel cell, molten carbonate fuel cell, or solid oxide fuel cell; wind turbine located in the state's territorial waters of Lake Erie; methane gas emitted from an abandoned coal mine; waste energy recovery system placed into service or retrofitted on or after the effective date of the amendment of this section by S.B. 315 of the 129th general assembly, September 10, 2012, except that a waste energy recovery system described in division (A)(38)(b) of this section may be included only if it was placed into service between January 1, 2002, and December 31, 2004; storage facility that will promote the better utilization of a renewable energy resource; or distributed generation system used by a customer to generate electricity from any such energy.

"Renewable energy resource" does not include a waste energy recovery system that is, or was, on or after January 1, 2012, included in an energy efficiency program of an electric distribution utility pursuant to requirements under section 4928.66 of the Revised Code.

(b) As used in division (A)(37) of this section, "hydroelectric facility" means a hydroelectric generating facility that is located at a dam on a river, or on any water discharged to a river, that is within or bordering this state or within or bordering an adjoining state and meets all of the following standards:

(i) The facility provides for river flows that are not detrimental for fish, wildlife, and water quality, including seasonal flow fluctuations as defined

by the applicable licensing agency for the facility.

(ii) The facility demonstrates that it complies with the water quality standards of this state, which compliance may consist of certification under Section 401 of the "Clean Water Act of 1977," 91 Stat. 1598, 1599, 33 U.S.C. 1341, and demonstrates that it has not contributed to a finding by this state that the river has impaired water quality under Section 303(d) of the "Clean Water Act of 1977," 114 Stat. 870, 33 U.S.C. 1313.

(iii) The facility complies with mandatory prescriptions regarding fish passage as required by the federal energy regulatory commission license issued for the project, regarding fish protection for riverine, anadromous, and catadromous fish.

(iv) The facility complies with the recommendations of the Ohio environmental protection agency and with the terms of its federal energy regulatory commission license regarding watershed protection, mitigation, or enhancement, to the extent of each agency's respective jurisdiction over the facility.

(v) The facility complies with provisions of the "Endangered Species Act of 1973," 87 Stat. 884, 16 U.S.C. 1531 to 1544, as amended.

(vi) The facility does not harm cultural resources of the area. This can be shown through compliance with the terms of its federal energy regulatory commission license or, if the facility is not regulated by that commission, through development of a plan approved by the Ohio historic preservation office, to the extent it has jurisdiction over the facility.

(vii) The facility complies with the terms of its federal energy regulatory commission license or exemption that are related to recreational access, accommodation, and facilities or, if the facility is not regulated by that commission, the facility complies with similar requirements as are recommended by resource agencies, to the extent they have jurisdiction over the facility; and the facility provides access to water to the public without fee or charge.

(viii) The facility is not recommended for removal by any federal agency or agency of any state, to the extent the particular agency has jurisdiction over the facility.

(38) "Waste energy recovery system" means either of the following:

(a) A facility that generates electricity through the conversion of energy from either of the following:

(i) Exhaust heat from engines or manufacturing, industrial, commercial, or institutional sites, except for exhaust heat from a facility whose primary purpose is the generation of electricity;

(ii) Reduction of pressure in gas pipelines before gas is distributed through the pipeline, provided that the conversion of energy to electricity is achieved without using additional fossil fuels.

(b) A facility at a state institution of higher education as defined in section 3345.011 of the Revised Code that recovers waste heat from electricity-producing engines or combustion turbines and that simultaneously uses the recovered heat to produce steam, provided that the facility was placed into service between January 1, 2002, and December 31, 2004.

(39) "Smart grid" means capital improvements to an electric distribution utility's distribution infrastructure that improve reliability, efficiency, resiliency, or reduce energy demand or use, including, but not limited to, advanced metering and automation of system functions.

(40) "Combined heat and power system" means the coproduction of electricity and useful thermal energy from the same fuel source designed to achieve thermal-efficiency levels of at least sixty per cent, with at least twenty per cent of the system's total useful energy in the form of thermal energy.

(B) For the purposes of this chapter, a retail electric service component shall be deemed a competitive retail electric service if the service component is competitive pursuant to a declaration by a provision of the Revised Code or pursuant to an order of the public utilities commission authorized under division (A) of section 4928.04 of the Revised Code. Otherwise, the service component shall be deemed a noncompetitive retail electric service.

**Sec. 4928.112.** (A) In the event of an interruption of electric service during a period of emergency or disaster, an electric distribution utility's service restoration plan shall give priority to hospitals that are customers of the electric distribution utility.

(B) If requested by a hospital that is its customer, an electric distribution utility shall confer at least biennially with that hospital regarding power quality issues and concerns related to the utility's facilities, including voltage sags, spikes, and harmonic disturbances, in an effort to minimize those events or their impact on the hospital.

(C) The public utilities commission shall adopt rules to carry out this section.

**Sec. 4928.20.** (A) The legislative authority of a municipal corporation may adopt an ordinance, or the board of township trustees of a township or the board of county commissioners of a county may adopt a resolution, under which, on or after the starting date of competitive retail electric service, it may aggregate in accordance with this section the retail electrical loads located, respectively, within the municipal corporation, township, or unincorporated area of the county and, for that purpose, may enter into service agreements to facilitate for those loads the sale and purchase of electricity. The legislative authority or board also may exercise such authority jointly with any other such legislative authority or board. For customers that are not mercantile customers, an ordinance or resolution under this division shall specify whether the aggregation will occur only with the prior, affirmative consent of each person owning, occupying, controlling, or using an electric load center proposed to be aggregated or will occur automatically for all such persons pursuant to the opt-out requirements of division (D) of this section. The aggregation of mercantile customers shall occur only with the prior, affirmative consent of each such person owning, occupying, controlling, or using an electric load center proposed to be aggregated. Nothing in this division, however, authorizes the aggregation of the retail electric loads of an electric load center, as defined in section 4933.81 of the Revised Code, that is located in the certified territory of a nonprofit electric supplier under sections 4933.81 to 4933.90 of the Revised Code or an electric load center served by transmission or distribution facilities of a municipal electric utility.

(B) If an ordinance or resolution adopted under division (A) of this section specifies that aggregation of customers that are not mercantile customers will occur automatically as described in that division, the ordinance or resolution shall direct the board of elections to submit the question of the authority to aggregate to the electors of the respective municipal corporation, township, or unincorporated area of a county at a special election on the day of the next primary or general election in the municipal corporation, township, or county. The legislative authority or board shall certify a copy of the ordinance or resolution to the board of elections not less than ninety days before the day of the special election. No ordinance or resolution adopted under division (A) of this section that provides for an election under this division shall take effect unless approved by a majority of the electors voting upon the ordinance or resolution at the election held pursuant to this division.

(C) Upon the applicable requisite authority under divisions (A) and (B) of this section, the legislative authority or board shall develop a plan of operation and governance for the aggregation program so authorized. Before adopting a plan under this division, the legislative authority or board shall hold at least two public hearings on the plan. Before the first hearing, the legislative authority or board shall publish notice of the hearings once a week for two consecutive weeks in a newspaper of general circulation in the jurisdiction or as provided in section 7.16 of the Revised Code. The notice shall summarize the plan and state the date, time, and location of each hearing.

(D) No legislative authority or board, pursuant to an ordinance or resolution under divisions (A) and (B) of this section that provides for automatic aggregation of customers that are not mercantile customers as described in division (A) of this section, shall aggregate the electrical load of any electric load center located within its jurisdiction unless it in advance clearly discloses to the person owning, occupying, controlling, or using the load center that the person will be enrolled automatically in the aggregation program and will remain so enrolled unless the person affirmatively elects by a stated procedure not to be so enrolled. The disclosure shall state prominently the rates, charges, and other terms and conditions of enrollment. The stated procedure shall allow any person enrolled in the aggregation program the opportunity to opt out of the program every three years, without paying a switching fee. Any such person that opts out before the commencement of the aggregation program pursuant to the stated procedure shall default to the standard service offer provided under section 4928.14 or division (D) of section 4928.35 of the Revised Code until the person chooses an alternative supplier.

(E)(1) With respect to a governmental aggregation for a municipal corporation that is authorized pursuant to divisions (A) to (D) of this section, resolutions may be proposed by initiative or referendum petitions in accordance with sections 731.28 to 731.41 of the Revised Code.

(2) With respect to a governmental aggregation for a township or the unincorporated area of a county, which aggregation is authorized pursuant to divisions (A) to (D) of this section, resolutions may be proposed by initiative or referendum petitions in accordance with sections 731.28 to 731.40 of the Revised Code, except that:

(a) The petitions shall be filed, respectively, with the township fiscal officer or the board of county commissioners, who shall perform those duties imposed under those sections upon the city auditor or village clerk.

(b) The petitions shall contain the signatures of not less than ten per cent of the total number of electors in, respectively, the township or the unincorporated area of the county who voted for the office of governor at the preceding general election for that office in that area.

(F) A governmental aggregator under division (A) of this section is not a public utility engaging in the wholesale purchase and resale of

electricity, and provision of the aggregated service is not a wholesale utility transaction. A governmental aggregator shall be subject to supervision and regulation by the public utilities commission only to the extent of any competitive retail electric service it provides and commission authority under this chapter.

(G) This section does not apply in the case of a municipal corporation that supplies such aggregated service to electric load centers to which its municipal electric utility also supplies a noncompetitive retail electric service through transmission or distribution facilities the utility singly or jointly owns or operates.

(H) A governmental aggregator shall not include in its aggregation the accounts of any of the following:

(1) A customer that has opted out of the aggregation;

(2) A customer in contract with a certified electric services company;

(3) A customer that has a special contract with an electric distribution utility;

(4) A customer that is not located within the governmental aggregator's governmental boundaries;

(5) Subject to division (C) of section 4928.21 of the Revised Code, a customer who appears on the "do not aggregate" list maintained under that section.

(I) Customers that are part of a governmental aggregation under this section shall be responsible only for such portion of a surcharge under section 4928.144 of the Revised Code that is proportionate to the benefits, as determined by the commission, that electric load centers within the jurisdiction of the governmental aggregation as a group receive. The proportionate surcharge so established shall apply to each customer of the governmental aggregation while the customer is part of that aggregation. If a customer ceases being such a customer, the otherwise applicable surcharge shall apply. Nothing in this section shall result in less than full recovery by an electric distribution utility of any surcharge authorized under section 4928.144 of the Revised Code. Nothing in this section shall result in less than the full and timely imposition, charging, collection, and adjustment by an electric distribution utility, its assignee, or any collection agent, of the phase-in-recovery charges authorized pursuant to a final financing order issued pursuant to sections 4928.23 to 4928.2318 of the Revised Code.

(J) On behalf of the customers that are part of a governmental aggregation under this section and by filing written notice with the public utilities commission, the legislative authority that formed or is forming that governmental aggregation may elect not to receive standby service within the meaning of division (B)(2)(d) of section 4928.143 of the Revised Code from an electric distribution utility in whose certified territory the governmental aggregation is located and that operates under an approved electric security plan under that section. Upon the filing of that notice, the electric distribution utility shall not charge any such customer to whom competitive retail electric generation service is provided by another supplier under the governmental aggregation for the standby service. Any such consumer that returns to the utility for competitive retail electric service shall pay the market price of power incurred by the utility to serve that consumer plus any amount attributable to the utility's cost of compliance with the ~~alternative~~ renewable energy resource provisions of section 4928.64 of the Revised Code to serve the consumer. Such market price shall include, but not be limited to, capacity and energy charges; all charges associated with the provision of that power supply through the regional transmission organization, including, but not limited to, transmission, ancillary services, congestion, and settlement and administrative charges; and all other costs incurred by the utility that are associated with the procurement, provision, and administration of that power supply, as such costs may be approved by the commission. The period of time during which the market price and ~~alternative~~ renewable energy resource amount shall be so assessed on the consumer shall be from the time the consumer so returns to the electric distribution utility until the expiration of the electric security plan. However, if that period of time is expected to be more than two years, the commission may reduce the time period to a period of not less than two years.

(K) The commission shall adopt rules to encourage and promote large-scale governmental aggregation in this state. For that purpose, the commission shall conduct an immediate review of any rules it has adopted for the purpose of this section that are in effect on the effective date of the amendment of this section by S.B. 221 of the 127th general assembly, July 31, 2008. Further, within the context of an electric security plan under section 4928.143 of the Revised Code, the commission shall consider the effect on large-scale governmental aggregation of any nonbypassable generation charges, however collected, that would be established under that plan, except any nonbypassable generation charges that relate to any cost incurred by the electric distribution utility, the deferral of which has been authorized by the commission prior to the effective date of the amendment of this section by S.B. 221 of the 127th general assembly, July 31, 2008.

**Sec. 4928.53.** (A) Beginning July 1, 2000, the director of development is hereby authorized to administer the low-income customer assistance programs. For that purpose, the public utilities commission shall cooperate with and provide such assistance as the director requires for administration of the low-income customer assistance programs. The director shall consolidate the administration of and redesign and coordinate the operations of those programs within the department to provide, to the maximum extent possible, for efficient program administration and a one-stop application and eligibility determination process at the local level for consumers.

(B)(1) Not later than March 1, 2000, the director, in accordance with Chapter 119. of the Revised Code, shall adopt rules to carry out sections 4928.51 to 4928.58 of the Revised Code and ensure the effective and efficient administration and operation of the low-income customer assistance programs. The rules shall take effect on ~~the~~ July 1, 2000.

(2) The director's authority to adopt rules under this division for the Ohio energy credit program shall be subject to such rule-making authority as is conferred on the director by sections 5117.01 to 5117.12 of the Revised Code, as amended by Sub. S.B. No. 3 of the 123rd general assembly, except that rules initially adopted by the director for the Ohio energy credit program shall incorporate the substance of those sections as they exist on the effective date of this section.

(3) The director's authority to adopt rules under this division for the percentage of income payment plan program shall include authority to adopt rules prescribing criteria for customer eligibility and policies regarding payment and crediting arrangements and responsibilities, procedures for verifying customer eligibility, procedures for disbursing public funds to suppliers and otherwise administering funds under the director's jurisdiction, and requirements as to timely remittances of revenues described in division (B) of section 4928.51 of the Revised Code. The rules shall prohibit the imposition of a waiting period before enrolling an eligible customer in the percentage of income payment plan. The director's authority in division (B)(3) of this section excludes authority to prescribe service disconnection and customer billing policies and procedures and to address complaints against suppliers under the percentage of payment plan program, which excluded authority shall be exercised by the public utilities commission, in coordination with the director. Rules adopted by the director under this division for the percentage of income payment plan program shall specify a level of payment responsibility to be borne by an eligible customer based on a percentage of the customer's income. Rules initially adopted by the director for the percentage of income payment plan program shall incorporate the eligibility criteria and payment arrangement and responsibility policies set forth in rule 4901:1-18-04(B) of the Ohio Administrative Code in effect on the effective date of this section.

**Sec. 4928.64.** (A)(1) As used in ~~sections 4928.64 and 4928.65 of the Revised Code~~ this section, "~~alternative~~ qualifying renewable energy resource" means ~~an advanced energy resource or~~ a renewable energy resource, as defined in section 4928.01 of the Revised Code that has a placed-in-service date ~~of~~ on or after January 1, 1998, or ~~after~~ with respect to any run-of-the-river hydroelectric facility, an in-service date on or after January 1, 1980; a renewable energy resource created on or after January 1, 1998, by the modification or retrofit of any facility placed in service prior to January 1, 1998; or a mercantile customer-sited ~~advanced energy resource or~~ renewable energy resource, whether new or existing, that the mercantile customer commits for integration into the electric distribution utility's demand-response, energy efficiency, or peak demand reduction programs as provided under division (A)(2)(c) of section 4928.66 of the Revised Code, including, but not limited to, any of the following:

(a) A resource that has the effect of improving the relationship between real and reactive power;

(b) A resource that makes efficient use of waste heat or other thermal capabilities owned or controlled by a mercantile customer;

(c) Storage technology that allows a mercantile customer more flexibility to modify its demand or load and usage characteristics;

(d) Electric generation equipment owned or controlled by a mercantile customer that uses ~~an advanced energy resource or~~ a renewable energy resource~~;~~

~~(e) Any advanced energy resource or renewable energy resource of the mercantile customer that can be utilized effectively as part of any advanced energy resource plan of an electric distribution utility and would otherwise qualify as an alternative energy resource if it were utilized directly by an electric distribution utility.~~

(2) For the purpose of this section and as it considers appropriate, the public utilities commission may classify any new technology as such ~~an advanced energy resource or~~ a qualifying renewable energy resource.

(B)(1) By ~~2025~~ 2027 and thereafter, an electric distribution utility shall provide from ~~alternative~~ qualifying renewable energy resources, including, at its discretion, ~~alternative~~ qualifying renewable energy resources obtained pursuant to an electricity supply contract, a portion of the electricity supply required for its standard service offer under section 4928.141 of the Revised Code, and an electric services company shall provide a portion of its electricity supply for retail consumers in this state from ~~alternative~~ qualifying renewable energy resources, including, at its discretion, ~~alternative~~ qualifying renewable energy resources obtained pursuant to an electricity supply contract. That portion shall equal ~~twenty-five~~ twelve and one-half per cent of the total number of kilowatt hours of electricity sold by the subject utility or company to any and all retail electric consumers whose electric load centers are

served by that utility and are located within the utility's certified territory or, in the case of an electric services company, are served by the company and are located within this state. However, nothing in this section precludes a utility or company from providing a greater percentage. ~~The baseline for a utility's or company's compliance with the alternative energy resource requirements of this section shall be the average of such total kilowatt-hours it sold in the preceding three calendar years, except that the commission may reduce a utility's or company's baseline to adjust for new economic growth in the utility's certified territory or, in the case of an electric services company, in the company's service area in this state.~~

~~Of the alternative energy resources implemented by the subject utility or company by 2025 and thereafter:~~

~~(1) Half may be generated from advanced energy resources;~~

(2) ~~At least half~~ The portion required under division (B)(1) of this section shall be generated from renewable energy resources, including one-half per cent from solar energy resources, in accordance with the following benchmarks:

| By end of year | Renewable energy resources | Solar energy resources |
|---|---|---|
| 2009 | 0.25% | 0.004% |
| 2010 | 0.50% | 0.010% |
| 2011 | 1% | 0.030% |
| 2012 | 1.5% | 0.060% |
| 2013 | 2% | 0.090% |
| 2014 | 2.5% | 0.12% |
| 2015 | ~~3.5~~ 2.5% | ~~0.15~~ 0.12% |
| 2016 | ~~4.5~~ 2.5% | ~~0.18~~ 0.12% |
| 2017 | ~~5.5~~ 3.5% | ~~0.22~~ 0.15% |
| 2018 | ~~6.5~~ 4.5% | ~~0.26~~ 0.18% |
| 2019 | ~~7.5~~ 5.5% | ~~0.3~~ 0.22% |
| 2020 | ~~8.5~~ 6.5% | ~~0.34~~ 0.26% |
| 2021 | ~~9.5~~ 7.5% | ~~0.38~~ 0.3% |
| 2022 | ~~10.5~~ 8.5% | ~~0.42~~ 0.34% |
| 2023 | ~~11.5~~ 9.5% | ~~0.46~~ 0.38% |
| 2024 ~~and each calendar year thereafter~~ | ~~12.5~~ 10.5% | ~~0.5~~ 0.42% |
| 2025 | 11.5% | 0.46% |
| 2026 and each calendar year thereafter | 12.5% | 0.5%. |

(3) ~~At least one-half of the~~ The qualifying renewable energy resources implemented by the utility or company shall be met ~~through~~ either:

(a) Through facilities located in this state; ~~the remainder shall be met with~~ or

(b) With resources that can be shown to be deliverable into this state.

(C)(1) The commission annually shall review an electric distribution utility's or electric services company's compliance with the most recent applicable benchmark under division (B)(2) of this section and, in the course of that review, shall identify any undercompliance or noncompliance of the utility or company that it determines is weather-related, related to equipment or resource shortages for ~~advanced energy or~~ qualifying renewable energy resources as applicable, or is otherwise outside the utility's or company's control.

(2) Subject to the cost cap provisions of division (C)(3) of this section, if the commission determines, after notice and opportunity for hearing, and based upon its findings in that review regarding avoidable undercompliance or noncompliance, but subject to division (C)(4) of this section, that the utility or company has failed to comply with any such benchmark, the commission shall impose a renewable energy compliance payment on the utility or company.

(a) The compliance payment pertaining to the solar energy resource benchmarks under division (B)(2) of this section shall be an amount per megawatt hour of undercompliance or noncompliance in the period under review, ~~starting at four~~ as follows:

(i) Three hundred ~~fifty~~ dollars for ~~2009, four~~ 2014, 2015, and 2016;

(ii) Two hundred fifty dollars for ~~2010~~ 2017 and ~~2011, and similarly~~ 2018;

(iii) Two hundred dollars for 2019 and 2020;

(iv) Similarly reduced every two years thereafter through ~~2024~~ 2026 by fifty dollars, to a minimum of fifty dollars.

(b) The compliance payment pertaining to the renewable energy resource benchmarks under division (B)(2) of this section shall equal the number of additional renewable energy credits that the electric distribution utility or electric services company would have needed to comply with the applicable benchmark in the period under review times an amount that shall begin at forty-five dollars and shall be adjusted annually by the commission to reflect any change in the consumer price index as defined in section 101.27 of the Revised Code, but shall not be less than forty-five dollars.

(c) The compliance payment shall not be passed through by the electric distribution utility or electric services company to consumers. The compliance payment shall be remitted to the commission, for deposit to the credit of the advanced energy fund created under section 4928.61 of the Revised Code. Payment of the compliance payment shall be subject to such collection and enforcement procedures as apply to the collection of a forfeiture under sections 4905.55 to 4905.60 and 4905.64 of the Revised Code.

(3) An electric distribution utility or an electric services company need not comply with a benchmark under division (B)~~(1) or~~ (2) of this section to the extent that its reasonably expected cost of that compliance exceeds its reasonably expected cost of otherwise producing or acquiring the requisite electricity by three per cent or more. The cost of compliance shall be calculated as though any exemption from taxes and assessments had not been granted under section 5727.75 of the Revised Code.

(4)(a) An electric distribution utility or electric services company may request the commission to make a force majeure determination pursuant to this division regarding all or part of the utility's or company's compliance with any minimum benchmark under division (B)(2) of this section during the period of review occurring pursuant to division (C)(2) of this section. The commission may require the electric distribution utility or electric services company to make solicitations for renewable energy resource credits as part of its default service before the utility's or company's request of force majeure under this division can be made.

(b) Within ninety days after the filing of a request by an electric distribution utility or electric services company under division (C)(4)(a) of this section, the commission shall determine if qualifying renewable energy resources are reasonably available in the marketplace in sufficient quantities for the utility or company to comply with the subject minimum benchmark during the review period. In making this determination, the commission shall consider whether the electric distribution utility or electric services company has made a good faith effort to acquire sufficient qualifying renewable energy or, as applicable, solar energy resources to so comply, including, but not limited to, by banking or seeking renewable energy resource credits or by seeking the

resources through long-term contracts. Additionally, the commission shall consider the availability of qualifying renewable energy or solar energy resources in this state and other jurisdictions in the PJM interconnection regional transmission organization, L.L.C., or its successor and the ~~midwest~~ midcontinent independent system operator or its successor.

(c) If, pursuant to division (C)(4)(b) of this section, the commission determines that qualifying renewable energy or solar energy resources are not reasonably available to permit the electric distribution utility or electric services company to comply, during the period of review, with the subject minimum benchmark prescribed under division (B)(2) of this section, the commission shall modify that compliance obligation of the utility or company as it determines appropriate to accommodate the finding. Commission modification shall not automatically reduce the obligation for the electric distribution utility's or electric services company's compliance in subsequent years. If it modifies the electric distribution utility or electric services company obligation under division (C)(4)(c) of this section, the commission may require the utility or company, if sufficient renewable energy resource credits exist in the marketplace, to acquire additional renewable energy resource credits in subsequent years equivalent to the utility's or company's modified obligation under division (C)(4)(c) of this section.

(5) The commission shall establish a process to provide for at least an annual review of the ~~alternative~~ renewable energy resource market in this state and in the service territories of the regional transmission organizations that manage transmission systems located in this state. The commission shall use the results of this study to identify any needed changes to the amount of the renewable energy compliance payment specified under divisions (C)(2)(a) and (b) of this section. Specifically, the commission may increase the amount to ensure that payment of compliance payments is not used to achieve compliance with this section in lieu of actually acquiring or realizing energy derived from qualifying renewable energy resources. However, if the commission finds that the amount of the compliance payment should be otherwise changed, the commission shall present this finding to the general assembly for legislative enactment.

(D)~~(1)~~ The commission annually shall submit to the general assembly in accordance with section 101.68 of the Revised Code a report describing all of the following:

~~(a)~~(1) The compliance of electric distribution utilities and electric services companies with division (B) of this section;

~~(b)~~(2) The average annual cost of renewable energy credits purchased by utilities and companies for the year covered in the report;

~~(c)~~(3) Any strategy for utility and company compliance or for encouraging the use of ~~alternative~~ qualifying renewable energy resources in supplying this state's electricity needs in a manner that considers available technology, costs, job creation, and economic impacts.

The commission shall begin providing the information described in division (D)~~(1)(b)~~(2) of this section in each report submitted after ~~the effective date of the amendment of this section by S.B. 315 of the 129th general assembly~~ September 10, 2012. The commission shall allow and consider public comments on the report prior to its submission to the general assembly. Nothing in the report shall be binding on any person, including any utility or company for the purpose of its compliance with any benchmark under division (B) of this section, or the enforcement of that provision under division (C) of this section.

~~(2) The governor, in consultation with the commission chairperson, shall appoint an alternative energy advisory committee. The committee shall examine available technology for and related timetables, goals, and costs of the alternative energy resource requirements under division (B) of this section and shall submit to the commission a semiannual report of its recommendations.~~

(E) All costs incurred by an electric distribution utility in complying with the requirements of this section shall be bypassable by any consumer that has exercised choice of supplier under section 4928.03 of the Revised Code.

**Sec. 4928.641.** (A) If an electric distribution utility has executed a contract before April 1, 2014, to procure renewable energy resources and there are ongoing costs associated with that contract that are being recovered from customers through a bypassable charge as of the effective date of S.B. 310 of the 130th general assembly, that cost recovery shall continue on a bypassable basis until the prudently incurred costs associated with that contract are fully recovered.

(B) Division (A) of this section applies only to costs associated with the original term of a contract described in that division and entered into before April 1, 2014. This section does not permit recovery of costs associated with an extension of such a contract. This section does not permit recovery of costs associated with an amendment of such a contract if that amendment was made on or after April 1, 2014.

**Sec. 4928.643.** (A) Except as provided in division (B) of this section and section 4928.644 of the Revised Code, the baseline for an electric distribution utility's or an electric services company's compliance with the qualified renewable energy resource requirements of section 4928.64 of the Revised Code shall be the average of total kilowatt hours sold by the utility or company in the preceding three calendar years to the following:

(1) In the case of an electric distribution utility, any and all retail electric consumers whose electric load centers are served by that utility and are located within the utility's certified territory;

(2) In the case of an electric services company, any and all retail electric consumers who are served by the company and are located within this state.

(B) Beginning with compliance year 2014, a utility or company may choose for its baseline for compliance with the qualified renewable energy resource requirements of section 4928.64 of the Revised Code to be the total kilowatt hours sold to the applicable consumers, as described in division (A)(1) or (2) of this section, in the applicable compliance year.

(C) A utility or company that uses the baseline permitted under division (B) of this section may use the baseline described in division (A) of this section in any subsequent compliance year. A utility or company that makes this switch shall use the baseline described in division (A) of this section for at least three consecutive compliance years before again using the baseline permitted under division (B) of this section.

**Sec. 4928.644.** The public utilities commission may reduce either baseline described in section 4928.643 of the Revised Code to adjust for new economic growth in the electric distribution utility's certified territory or in the electric services company's service area in this state.

**Sec. 4928.65 4928.645.** (A) An electric distribution utility or electric services company may use, for the purpose of complying with the requirements under divisions (B)(1) and (2) of section 4928.64 of the Revised Code, renewable energy credits any time in the five calendar years following the date of their purchase or acquisition from any entity, including, but not limited to, ~~a~~ the following:

(1) A mercantile customer ~~or an~~;

(2) An owner or operator of a hydroelectric generating facility that is located at a dam on a river, or on any water discharged to a river, that is within or bordering this state or within or bordering an adjoining state, ~~for the purpose of complying with the renewable energy and solar energy resource requirements of division (B)(2) of section 4928.64 of the Revised Code~~ or that produces power that can be shown to be deliverable into this state;

(3) A seller of compressed natural gas that has been produced from biologically derived methane gas, provided that the seller may only provide renewable energy credits for metered amounts of gas. ~~The~~

(B)(1) The public utilities commission shall adopt rules specifying that one unit of credit shall equal one megawatt hour of electricity derived from renewable energy resources, except that, for a generating facility of seventy-five megawatts or greater that is situated within this state and has committed by December 31, 2009, to modify or retrofit its generating unit or units to enable the facility to generate principally from biomass energy by June 30, 2013, each megawatt hour of electricity generated principally from that biomass energy shall equal, in units of credit, the product obtained by multiplying the actual percentage of biomass feedstock heat input used to generate such megawatt hour by the quotient obtained by dividing the then existing unit dollar amount used to determine a renewable energy compliance payment as provided under division (C)(2)(b) of section 4928.64 of the Revised Code by the then existing market value of one renewable energy credit, but such megawatt hour shall not equal less than one unit of credit. Renewable energy resources do not have to be converted to electricity in order to be eligible to receive renewable energy credits. The rules shall specify that, for purposes of converting the quantity of energy derived from biologically derived methane gas to an electricity equivalent, one megawatt hour equals 3,412,142 British thermal units.

(2) The rules also shall provide for this state a system of registering renewable energy credits by specifying which of any generally available registries shall be used for that purpose and not by creating a registry. That selected system of registering renewable energy credits shall allow a hydroelectric generating facility to be eligible for obtaining renewable energy credits and shall allow customer-sited projects or actions the broadest opportunities to be eligible for obtaining renewable energy credits.

**Sec. 4928.65.** (A) Not later than January 1, 2015, the public utilities commission shall adopt rules governing the disclosure of the costs to customers of the renewable energy resource, energy efficiency savings, and peak demand reduction requirements of sections 4928.64 and 4928.66 of the Revised Code. The rules shall include both of the following requirements:

(1) That every electric distribution utility list, on all customer bills sent by the utility, including utility consolidated bills that include both electric distribution utility and electric services company charges, the individual customer cost of the utility's compliance with all of the following for the applicable billing period:

(a) The renewable energy resource requirements under section 4928.64 of the Revised Code, subject to division (B) of this section;

(b) The energy efficiency savings requirements under section 4928.66 of the Revised Code;

(c) The peak demand reduction requirements under section 4928.66 of the Revised Code.

(2) That every electric services company list, on all customer bills sent by the company, the individual customer cost, subject to division (B) of this section, of the company's compliance with the renewable energy resource requirements under section 4928.64 of the Revised Code for the applicable billing period.

(B)(1) For purposes of division (A)(1)(a) of this section, the cost of compliance with the renewable energy resource requirements shall be calculated by multiplying the individual customer's monthly usage by the combined weighted average of renewable-energy-credit costs, including solar-renewable-energy-credit costs, paid by all electric distribution utilities, as listed in the commission's most recently available alternative energy portfolio standard report.

(2) For purposes of division (A)(2) of this section, the cost of compliance with the renewable energy resource requirements shall be calculated by multiplying the individual customer's monthly usage by the combined weighted average of renewable-energy-credit costs, including solar-renewable-energy-credit costs, paid by all electric services companies, as listed in the commission's most recently available alternative energy portfolio standard report.

(C) The costs required to be listed under division (A)(1) of this section shall be listed on each customer's monthly bill as three distinct line items. The cost required to be listed under division (A)(2) of this section shall be listed on each customer's monthly bill as a distinct line item.

**Sec. 4928.66.** (A)(1)(a) Beginning in 2009, an electric distribution utility shall implement energy efficiency programs that achieve energy savings equivalent to at least three-tenths of one per cent of the total, annual average, and normalized kilowatt-hour sales of the electric distribution utility during the preceding three calendar years to customers in this state. An energy efficiency program may include a combined heat and power system placed into service or retrofitted on or after the effective date of the amendment of this section by S.B. 315 of the 129th general assembly, September 10, 2012, or a waste energy recovery system placed into service or retrofitted on or after ~~the same date~~ September 10, 2012, except that a waste energy recovery system described in division (A)(38)(b) of section 4928.01 of the Revised Code may be included only if it was placed into service between January 1, 2002, and December 31, 2004. For a waste energy recovery or combined heat and power system, the savings shall be as estimated by the public utilities commission. The savings requirement, using such a three-year average, shall increase to an additional five-tenths of one per cent in 2010, seven-tenths of one per cent in 2011, eight-tenths of one per cent in 2012, nine-tenths of one per cent in 2013, and one per cent ~~from~~ in 2014 ~~to~~. In 2015 and 2016, an electric distribution utility shall achieve energy savings equal to the result of subtracting the cumulative energy savings achieved since 2009 from the product of multiplying the baseline for energy savings, described in division (A)(2)(a) of this section, by four and two-tenths of one per cent. If the result is zero or less for the year for which the calculation is being made, the utility shall not be required to achieve additional energy savings for that year, but may achieve additional energy savings for that year. Thereafter, the annual savings requirements shall be, for years 2017, 2018, 2019, and 2020, one per cent of the baseline, and two per cent each year thereafter, achieving a cumulative~~, annual~~ energy savings in excess of twenty-two per cent by the end of ~~2025~~ 2027. For purposes of a waste energy recovery or combined heat and power system, an electric distribution utility shall not apply more than the total annual percentage of the electric distribution utility's industrial-customer load, relative to the electric distribution utility's total load, to the annual energy savings requirement.

(b) Beginning in 2009, an electric distribution utility shall implement peak demand reduction programs designed to achieve a one per cent reduction in peak demand in 2009 and an additional seventy-five hundredths of one per cent reduction each year through ~~2018~~ 2014. In ~~2018~~ 2015 and 2016, ~~the standing committees in the house of representatives and the senate primarily dealing with energy issues shall make recommendations to the general assembly regarding future~~ an electric distribution utility shall achieve a reduction in peak demand equal to the result of subtracting the cumulative peak demand reductions achieved since 2009 from the product of multiplying the baseline for peak demand reduction, described in division (A)(2)(a) of this section, by four and seventy-five hundredths of one per cent. If the result is zero or less for the year for which the calculation is being made, the utility shall not be required to achieve an additional reduction in peak demand for that year, but may achieve an additional reduction in peak demand for that year. In 2017 and each year thereafter through 2020, the utility shall achieve an additional seventy-five hundredths of one per cent reduction in peak demand ~~reduction targets~~.

(2) For the purposes of divisions (A)(1)(a) and (b) of this section:

(a) The baseline for energy savings under division (A)(1)(a) of this section shall be the average of the total kilowatt hours the electric distribution utility sold in the preceding three calendar years~~, and the~~. The baseline for a peak demand reduction under division (A)(1)(b) of this section shall be the average peak demand on the utility in the preceding three calendar years, except that the commission may reduce either baseline to adjust for new economic growth in the utility's certified territory. Neither baseline shall include the load and usage of any of the following customers:

(i) Beginning January 1, 2017, a customer for which a reasonable arrangement has been approved under section 4905.31 of the Revised Code;

(ii) A customer that has opted out of the utility's portfolio plan under section 4928.6611 of the Revised Code;

(iii) A customer that has opted out of the utility's portfolio plan under Section 8 of S.B. 310 of the 130th general assembly.

(b) The commission may amend the benchmarks set forth in division (A)(1)(a) or (b) of this section if, after application by the electric distribution utility, the commission determines that the amendment is necessary because the utility cannot reasonably achieve the benchmarks due to regulatory, economic, or technological reasons beyond its reasonable control.

(c) Compliance with divisions (A)(1)(a) and (b) of this section shall be measured by including the effects of all demand-response programs for mercantile customers of the subject electric distribution utility, all waste energy recovery systems and all combined heat and power systems, and all such mercantile customer-sited energy efficiency, including waste energy recovery and combined heat and power, and peak demand reduction programs, adjusted upward by the appropriate loss factors. Any mechanism designed to recover the cost of energy efficiency, including waste energy recovery and combined heat and power, and peak demand reduction programs under divisions (A)(1)(a) and (b) of this section may exempt mercantile customers that commit their demand-response or other customer-sited capabilities, whether existing or new, for integration into the electric distribution utility's demand-response, energy efficiency, including waste energy recovery and combined heat and power, or peak demand reduction programs, if the commission determines that that exemption reasonably encourages such customers to commit those capabilities to those programs. If a mercantile customer makes such existing or new demand-response, energy efficiency, including waste energy recovery and combined heat and power, or peak demand reduction capability available to an electric distribution utility pursuant to division (A)(2)(c) of this section, the electric utility's baseline under division (A)(2)(a) of this section shall be adjusted to exclude the effects of all such demand-response, energy efficiency, including waste energy recovery and combined heat and power, or peak demand reduction programs that may have existed during the period used to establish the baseline. The baseline also shall be normalized for changes in numbers of customers, sales, weather, peak demand, and other appropriate factors so that the compliance measurement is not unduly influenced by factors outside the control of the electric distribution utility.

(d)(i) Programs implemented by a utility may include ~~demand-response~~ the following:

(I) Demand-response programs ~~grid~~;

(II) Smart grid investment programs, provided that such programs are demonstrated to be cost-beneficial~~, customer-sited~~;

(III) Customer-sited programs, including waste energy recovery and combined heat and power systems~~, and transmission~~;

(IV) Transmission and distribution infrastructure improvements that reduce line losses;

(V) Energy efficiency savings and peak demand reduction that are achieved, in whole or in part, as a result of funding provided from the universal service fund established by section 4928.51 of the Revised Code to benefit low-income customers through programs that include, but are not limited to, energy audits, the installation of energy efficiency insulation, appliances, and windows, and other weatherization measures.

(ii) No energy efficiency or peak demand reduction achieved under divisions (A)(2)(d)(i)(IV) and (V) of this section shall qualify for shared savings.

(iii) Division (A)(2)(c) of this section shall be applied to include facilitating efforts by a mercantile customer or group of those customers to offer customer-sited demand-response, energy efficiency, including waste energy recovery and combined heat and power, or peak demand reduction capabilities to the electric distribution utility as part of a reasonable arrangement submitted to the commission pursuant to section 4905.31 of the Revised Code.

(e) No programs or improvements described in division (A)(2)(d) of this section shall conflict with any statewide building code adopted by the board of building standards.

(B) In accordance with rules it shall adopt, the public utilities commission shall produce and docket at the commission an annual report containing the results of its verification of the annual levels of energy efficiency and of peak demand reductions achieved by each electric distribution utility

pursuant to division (A) of this section. A copy of the report shall be provided to the consumers' counsel.

(C) If the commission determines, after notice and opportunity for hearing and based upon its report under division (B) of this section, that an electric distribution utility has failed to comply with an energy efficiency or peak demand reduction requirement of division (A) of this section, the commission shall assess a forfeiture on the utility as provided under sections 4905.55 to 4905.60 and 4905.64 of the Revised Code, either in the amount, per day per undercompliance or noncompliance, relative to the period of the report, equal to that prescribed for noncompliances under section 4905.54 of the Revised Code, or in an amount equal to the then existing market value of one renewable energy credit per megawatt hour of undercompliance or noncompliance. Revenue from any forfeiture assessed under this division shall be deposited to the credit of the advanced energy fund created under section 4928.61 of the Revised Code.

(D) The commission may establish rules regarding the content of an application by an electric distribution utility for commission approval of a revenue decoupling mechanism under this division. Such an application shall not be considered an application to increase rates and may be included as part of a proposal to establish, continue, or expand energy efficiency or conservation programs. The commission by order may approve an application under this division if it determines both that the revenue decoupling mechanism provides for the recovery of revenue that otherwise may be forgone by the utility as a result of or in connection with the implementation by the electric distribution utility of any energy efficiency or energy conservation programs and reasonably aligns the interests of the utility and of its customers in favor of those programs.

(E) The commission additionally shall adopt rules that require an electric distribution utility to provide a customer upon request with two years' consumption data in an accessible form.

**Sec. 4928.662.** For the purpose of measuring and determining compliance with the energy efficiency and peak demand reduction requirements under section 4928.66 of the Revised Code, the public utilities commission shall count and recognize compliance as follows:

(A) Energy efficiency savings and peak demand reduction achieved through actions taken by customers or through electric distribution utility programs that comply with federal standards for either or both energy efficiency and peak demand reduction requirements, including resources associated with such savings or reduction that are recognized as capacity resources by the regional transmission organization operating in Ohio in compliance with section 4928.12 of the Revised Code, shall count toward compliance with the energy efficiency and peak demand reduction requirements.

(B) Energy efficiency savings and peak demand reduction achieved on and after the effective date of S.B. 310 of the 130th general assembly shall be measured on the higher of an as found or deemed basis, except that, solely at the option of the electric distribution utility, such savings and reduction achieved since 2006 may also be measured using this method. For new construction, the energy efficiency savings and peak demand reduction shall be counted based on 2008 federal standards, provided that when new construction replaces an existing facility, the difference in energy consumed, energy intensity, and peak demand between the new and replaced facility shall be counted toward meeting the energy efficiency and peak demand reduction requirements.

(C) The commission shall count both the energy efficiency savings and peak demand reduction on an annualized basis.

(D) The commission shall count both the energy efficiency savings and peak demand reduction on a gross savings basis.

(E) The commission shall count energy efficiency savings and peak demand reductions associated with transmission and distribution infrastructure improvements that reduce line losses. No energy efficiency or peak demand reduction achieved under division (E) of this section shall qualify for shared savings.

(F) Energy efficiency savings and peak demand reduction amounts approved by the commission shall continue to be counted toward achieving the energy efficiency and peak demand reduction requirements as long as the requirements remain in effect.

(G) Any energy efficiency savings or peak demand reduction amount achieved in excess of the requirements may, at the discretion of the electric distribution utility, be banked and applied toward achieving the energy efficiency or peak demand reduction requirements in future years.

**Sec. 4928.6610.** As used in sections 4928.6611 to 4928.6616 of the Revised Code:

(A) "Customer" means any customer of an electric distribution utility to which either of the following applies:

(1) The customer receives service above the primary voltage level as determined by the utility's tariff classification.

(2) The customer is a commercial or industrial customer to which both of the following apply:

(a) The customer receives electricity through a meter of an end user or through more than one meter at a single location in a quantity that exceeds forty-five million kilowatt hours of electricity for the preceding calendar year.

(b) The customer has made a written request for registration as a self-assessing purchaser pursuant to section 5727.81 of the Revised Code.

(B) "Energy intensity" means the amount of energy, from electricity, used or consumed per unit of production.

(C) "Portfolio plan" means the comprehensive energy efficiency and peak-demand reduction program portfolio plan required under rules adopted by the public utilities commission and codified in Chapter 4901:1-39 of the Administrative Code or hereafter recodified or amended.

**Sec. 4928.6611.** Beginning January 1, 2017, a customer of an electric distribution utility may opt out of the opportunity and ability to obtain direct benefits from the utility's portfolio plan. Such an opt out shall extend to all of the customer's accounts, irrespective of the size or service voltage level that are associated with the activities performed by the customer and that are located on or adjacent to the customer's premises.

**Sec. 4928.6612.** Any customer electing to opt out under section 4928.6611 of the Revised Code shall do so by providing a verified written notice of intent to opt out to the electric distribution utility from which it receives service and submitting a complete copy of the opt-out notice to the secretary of the public utilities commission.

The notice provided to the utility shall include all of the following:

(A) A statement indicating that the customer has elected to opt out;

(B) The effective date of the election to opt out;

(C) The account number for each customer account to which the opt out shall apply;

(D) The physical location of the customer's load center;

(E) The date upon which the customer established, or plans to establish a process and implement, cost-effective measures to improve its energy efficiency savings and peak demand reductions.

**Sec. 4928.6613.** Upon a customer's election to opt out under section 4928.6611 of the Revised Code and commencing on the effective date of the election to opt out, no account properly identified in the customer's verified notice under division (C) of section 4928.6612 of the Revised Code shall be subject to any cost recovery mechanism under section 4928.66 of the Revised Code or eligible to participate in, or directly benefit from, programs arising from electric distribution utility portfolio plans approved by the public utilities commission.

**Sec. 4928.6614.** (A) A customer subsequently may opt in to an electric distribution utility's portfolio plan after a previous election to opt out under section 4928.6611 of the Revised Code if both of the following apply:

(1) The customer has previously opted out for a period of at least three consecutive calendar years.

(2) The customer gives twelve months' advance notice of its intent to opt in to the public utilities commission and the electric distribution utility from which it receives service.

(B) A customer that opts in under this section shall maintain its opt-in status for three consecutive calendar years before being eligible subsequently to exercise its right to opt out after giving the utility twelve months' advance notice.

**Sec. 4928.6615.** Any customer electing to opt in under section 4928.6614 of the Revised Code shall do so by providing a written notice of intent to opt in to the electric distribution utility from which it receives service and submitting a complete copy of the opt-in notice to the secretary of the public utilities commission. The notice shall include all of the following:

(A) A statement indicating that the customer has elected to opt in;

(B) The effective date of the election to opt in;

(C) The account number for each customer account to which the opt in shall apply;

(D) The physical location of the customer's load center.

**Sec. 4928.6616.** (A) Not later than sixty days after the effective date of a customer's election to opt out under section 4928.6611 of the Revised Code, the customer shall prepare and submit an initial report to the staff of the public utilities commission. The report shall summarize the projects, actions, policies, or practices that the customer may consider implementing, based on the customer's cost-effectiveness criteria, for the purpose of reducing energy intensity.

(B) For as long as the opt out is in effect, the customer shall, at least once every twenty-four months, commencing with the effective date of the election to opt out, prepare and submit, to the staff of the commission, an updated report. The updated report shall include a general description of any cumulative amount of energy-intensity reductions achieved by the customer during the period beginning on the effective date of the election to opt out and ending not later than sixty days prior to the date that the updated report is submitted.

(C) All reports filed under this section shall be verified by the customer.

(D) Upon submission of any updated report under division (B) of this section, the staff of the commission may request the customer to provide additional information on the energy-intensity-reducing projects, actions, policies, or practices implemented by the customer and the amount of energy-intensity reductions achieved during the period covered by the updated report.

(E) Any information contained in any report submitted under this section and any customer responses to requests for additional information shall be deemed to be confidential, proprietary, and a trade secret. No such information or response shall be publicly divulged without written authorization by the customer or used for any purpose other than to identify the amount of energy-intensity reductions achieved by the customer.

(F) If the commission finds, after notice and a hearing, that the customer has failed to achieve any substantial cumulative reduction in energy intensity identified by the customer in an updated report submitted under division (B) of this section, and if the failure is not excusable for good cause shown by the customer, the commission may suspend the opt out for the period of time that it may take the customer to achieve the cumulative reduction in energy intensity identified by the customer but no longer.

**SECTION 2.** That existing sections 3706.25, 4928.01, 4928.20, 4928.53, 4928.64, 4928.65, and 4928.66 of the Revised Code are hereby repealed.

**SECTION 3.** It is the intent of the General Assembly to ensure that customers in Ohio have access to affordable energy. It is the intent of the General Assembly to incorporate as many forms of inexpensive, reliable energy sources in the state of Ohio as possible. It is also the intent of the General Assembly to get a better understanding of how energy mandates impact jobs and the economy in Ohio and to minimize government mandates. Because the energy mandates in current law may be unrealistic and unattainable, it is the intent of the General Assembly to review all energy resources as part of its efforts to address energy pricing issues.

Therefore, it is the intent of the General Assembly to enact legislation in the future, after taking into account the recommendations of the Energy Mandates Study Committee, that will reduce the mandates in sections 4928.64 and 4928.66 of the Revised Code and provide greater transparency to electric customers on the costs of future energy mandates, if there are to be any.

**SECTION 4.** (A) There is hereby created the Energy Mandates Study Committee to study Ohio's renewable energy, energy efficiency, and peak demand reduction mandates. The Committee shall consist of the following members:

(1) Six members of the House of Representatives appointed by the Speaker of the House of Representatives, with not more than four members from the same political party;

(2) Six members of the Senate appointed by the President of the Senate, with not more than four members from the same political party;

(3) The chairperson of the Public Utilities Commission, as an ex officio, nonvoting member.

(B) The Speaker of the House of Representatives and the President of the Senate shall each appoint one member of the Committee to serve as a cochairperson of the Committee. Any vacancies that occur on the Committee shall be filled in the same manner as the original appointment.

(C) Not later than September 30, 2015, the Committee shall submit a report of its findings to the House of Representatives and the Senate in accordance with division (B) of section 101.68 of the Revised Code. The Committee shall cease to exist on October 1, 2015. The report shall include, at a minimum, all of the following:

(1) A cost-benefit analysis of the renewable energy, energy efficiency, and peak demand reduction mandates, including the projected costs on electric customers if the mandates were to remain at the percentage levels required under sections 4928.64 and 4928.66 of the Revised Code, as amended by this act;

(2) A recommendation of the best, evidence-based standard for reviewing the mandates in the future, including an examination of readily available technology to attain such a standard;

(3) The potential benefits of an opt-in system for the mandates, in contrast to an opt-out system for the mandates, and a recommendation as to whether an opt-in system should apply to all electric customers, whether an opt-out system should apply to only certain customers, or whether a hybrid of these two systems is recommended;

(4) A recommendation on whether costs incurred by an electric distribution utility or an electric services company pursuant to any contract, which may be entered into by the utility or company on or after the effective date of S.B. 310 of the 130th General Assembly for the purpose of procuring renewable energy resources or renewable energy credits and complying with the requirements of section 4928.64 of the Revised Code, may be passed through to any consumer, if such costs could have been avoided with the inclusion of a change of law provision in the contract;

(5) A review of the risk of increased grid congestion due to the anticipated retirement of coal-fired generation capacity and other factors; the ability of distributed generation, including combined heat and power and waste energy recovery, to reduce electric grid congestion; and the potential benefit to all energy consumers resulting from reduced grid congestion;

(6) An analysis of whether there are alternatives for the development of advanced energy resources as that term is defined in section 4928.01 of the Revised Code;

(7) An assessment of the environmental impact of the renewable energy, energy efficiency, and peak demand reduction mandates on reductions of greenhouse gas and fossil fuel emissions;

(8) A review of payments made by electric distribution utilities to third-party administrators to promote energy efficiency and peak demand reduction programs under the terms of the utilities' portfolio plans. The review shall include, but shall not be limited to, a complete analysis of all fixed and variable payments made to those administrators since the effective date of S.B. 221 of the 127th General Assembly, jobs created, retained, and impacted, whether those payments outweigh the benefits to ratepayers, and whether those payments should no longer be recovered from ratepayers. The review also shall include a recommendation regarding whether the administrators should submit periodic reports to the Commission documenting the payments received from utilities.

**SECTION 5.** As used in Sections 6, 7, 8, 9, 10, and 11 of this act:

"Customer," "energy intensity," and "portfolio plan" have the same meanings as in section 4928.6610 of the Revised Code.

"Electric distribution utility" has the same meaning as in section 4928.01 of the Revised Code.

**SECTION 6.** (A) If an electric distribution utility has a portfolio plan that is in effect on the effective date of this section, the utility shall do either of the following, at its sole discretion:

(1) Continue to implement the portfolio plan with no amendments to the plan, for the duration that the Public Utilities Commission originally approved, subject to divisions (D) and (E) of this section;

(2) Seek an amendment of the portfolio plan under division (B) of this section.

(B)(1) An electric distribution utility that seeks to amend its portfolio plan under division (A)(2) of this section shall file an application with the Commission to amend the plan not later than thirty days after the effective date of this section. The Commission shall review the application in accordance with its rules as if the application were for a new portfolio plan. The Commission shall review and approve, or modify and approve, the application not later than sixty days after the date that the application is filed. Any portfolio plan amended under this division shall take effect on January 1, 2015, and expire on December 31, 2016. If the Commission fails to review and approve, or modify and approve, the application on or before January 1, 2015, the plan shall

be deemed approved as amended in the application and shall take effect on January 1, 2015, and expire on December 31, 2016.

(2) Section 4928.66 of the Revised Code, as amended by this act, shall apply to an electric distribution utility that applies to amend its portfolio plan under division (B) of this section.

(C) If an electric distribution utility fails to file an application to amend its portfolio plan under division (B) of this section within the required thirty-day period, the electric distribution utility shall proceed in accordance with division (A)(1) of this section.

(D) If an electric distribution utility implements its portfolio plan under division (A)(1) of this section for the plan's original duration and if the plan expires before December 31, 2016, the Commission shall automatically extend the plan through December 31, 2016, with no amendments to the plan.

(E)(1) The provisions of section 4928.66 of the Revised Code, as it existed prior to the effective date of this section, shall apply to an electric distribution utility that has a portfolio plan that is implemented under division (A)(1) of this section for either of the following time periods:

(a) The plan's original duration;

(b) The plan's original duration and then, until December 31, 2016, if the plan is extended under division (D) of this section.

(2) Beginning January 1, 2017, the provisions of section 4928.66 of the Revised Code as amended by this act shall apply to the electric distribution utility.

**SECTION 7.** (A) The Public Utilities Commission shall neither review nor approve an application for a portfolio plan if the application is pending on the effective date of this section.

(B) Prior to January 1, 2017, the Commission shall not take any action with regard to any portfolio plan or application regarding a portfolio plan, except those actions expressly authorized or required by Section 6 of this act and actions necessary to administer the implementation of existing portfolio plans.

**SECTION 8.** Beginning January 1, 2015, a customer of an electric distribution utility may opt out of the opportunity and ability to obtain direct benefits from the utility's portfolio plan that is amended under division (B) of Section 6 of this act. The opt out shall apply only to the amended plan. The opt out shall extend to all of the customer's accounts, irrespective of the size or service voltage level that are associated with the activities performed by the customer and that are located on or adjacent to the customer's premises.

**SECTION 9.** Any customer electing to opt out under Section 8 of this act shall do so by providing a verified written notice of intent to opt out to the electric distribution utility from which it receives service and submitting a complete copy of the opt-out notice to the Secretary of the Public Utilities Commission.

The notice provided to the utility shall include all of the following:

(A) A statement indicating that the customer has elected to opt out;

(B) The effective date of the election to opt out;

(C) The account number for each customer account to which the opt out shall apply;

(D) The physical location of the customer's load center;

(E) The date upon which the customer established, or plans to establish a process and implement, cost-effective measures to improve its energy efficiency savings and peak demand reductions.

**SECTION 10.** Upon a customer's election to opt out under Section 8 of this act and commencing on the effective date of the election to opt out, no account properly identified in the customer's verified notice under division (C) of Section 9 of this act shall be subject to any cost recovery mechanism under section 4928.66 of the Revised Code, as amended by this act, for the duration of the amended portfolio plan or eligible to participate in, or directly benefit from, programs arising from the amended portfolio plan.

**SECTION 11.** (A) Not later than sixty days after the effective date of a customer's election to opt out under Section 8 of this act, the customer shall prepare and submit an initial report to the staff of the Public Utilities Commission. The report shall summarize the projects, actions, policies, or practices that the customer may consider implementing, based on the customer's cost-effectiveness criteria, for the purpose of reducing energy intensity.

(B) Not later than November 1, 2016, the customer shall prepare and submit to the staff of the Commission an updated report. The updated report shall include a general description of any cumulative amount of energy-intensity reductions achieved by the customer during the period beginning on the effective date of the election to opt out and ending not later than sixty days prior to the date that the updated report is submitted.

(C) Any report filed under this section shall be verified by the customer.

(D) Upon submission of the updated report, the staff of the Commission may request the customer to provide additional information on the energy-intensity-reducing projects, actions, policies, or practices implemented by the customer and the amount of energy-intensity reductions achieved during the period covered by the updated report.

(E) Any information contained in any report submitted under this section and any customer responses to requests for additional information shall be deemed to be confidential, proprietary, and a trade secret. No such information or response shall be publicly divulged without written authorization by the customer or used for any purpose other than to identify the amount of energy-intensity reductions achieved by the customer.

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# Appendix P:

# LADCO Comments on EPA's 2018 Modeling Platform

LADCO Comments on EPA's 2018 Modeling Platform
June 30th 2014

## General Comments

The LADCO states have reviewed the 2018 Electric Generating Units(EGU) Emissions Inventories created with the economic based model IPM. We have four significant concerns about the use of IPM in policy inventory and chemical transport modeling. These general concerns can be traced to the results of specific units or may affect large groups of units in smaller ways. LADCO believes that the ERTAC EGU projection system is a more appropriate tool for utility projection

Our first concern is the economic optimization of the IPM model. Currently the IPM model creates a future year estimate based on a least cost algorithm. The model optimizes the power production and delivery system into its most financially efficient system. The difficulty is that the power production system is not completely governed by economics. Reliability, emissions credit trading, and corporate/organizational inertia can all influence where companies select to generate power. The juxtaposition of these two ideas are best manifested and illustrated in the handling of a single large oil burning unit in Virginia called Possum Point. On peak days Possum Point has significant generation, also the unit runs during the spring maintenance periods of the nuclear plants in Virginia. IPM regularly shuts down Possum Point and has for the past 10 years because its operation does not make sense in a purely economic framework. We believe that a fully optimized economics based projection tool is an inappropriate mechanism for building future policy frameworks or setting policy budgets. We also believe that EPA's method of using IPM results in Photochemical models needs improvement especially when it is used to define impacts at specific monitors.

Our second concern with EPA's current implementation of IPM is the models over estimation of the use of controls likely to result from the Mercury and Air Toxics Rule(MATS). EPA's model is currently including significant levels of control for MATS that mimic a .20 LB/MMBTU standard spelled out in the rule. After conversations with stakeholders and the states it appears that MATS will likely be complied with by using Dry Sorbent Injection(DSI) as opposed to Scrubbers which are favored by IPM. We suggest that EPA re-evaluate their use of DSI as a compliance method for the MATS Rule. For example Bailly Generating Station in Indiana(ORIS 995 units 7 and 8) According to our records will be operating at 0.12 lb/mmBTU for NOX by 2015 as a 365 day rolling average which matches IPM but, we expect them to add ACI for MATS for SO2 in the future which is much lower control effectiveness than IPM.

| ORIS 995 | 2018_NOX_ERTAC (tons) | 2018_OS_NOX_ERTAC (tons) | IPM_NOX (tons) | IPM_OS_NOX (tons) | Annual (Diff tons) | OS (Diff tons) |
|---|---|---|---|---|---|---|
| Unit 7 | 691.307 | 222.254 | 476.948 | 207.8 | 214.359 | 14.4536 |
| Unit 8 | 1339.1 | 578.814 | 937.406 | 408.416 | 401.694 | 170.397 |

Our third concern is that IPM and EPA are assuming that all existing controls including scrubbers and SCRs will be operated in the future year. We saw from 2011-2013 that units are now buying NOX allowances and using those credits to turn off their SCRs during peak summer conditions. Currently the high cost of ammonia is driving some units to purchase allowances. We believe that there are no significant policy drivers that would force a change in activities between 2011 and 2018. We believe it is incorrect to include these controls unless a clearly defined mechanism indicated that these changes are likely.

Our Fourth and most critical concern about the use of IPM for policy and science development at EPA is the use of results that show economics based shutdowns mostly in the coal sector. There are many reasons that units would run that are independent of pure economics. The first and most critical is system reliability. There are many units that IPM is either shutting down or running at less than 10% of base year activity. We believe that the localized impact of these shutdowns especially when in close proximity to non-attainment areas can be severely detrimental to EPA's understanding of future year impacts. We believe that EPA must consider alternative methods to project electric utility emission than IPM. We also believe that budgets based on IPM projections are likely very flawed and have been in the past. Here are the units we believe IPM/EPA incorrectly retired/Shutdown/or under-utilized in 2018.

Table A. Units incorrectly shut down or under-utilized in EPA's 2018 Estimates.

| ORIS ID | Unit_ID | Facility Name | State | Region | Fuel |
|---|---|---|---|---|---|
| 856 | 2 | E D Edwards | IL | SRGW | coal |
| 883 | 312 | Waukegan | IL | RFCW | Oil |
| 887 | 1 | Joppa Steam | IL | SRGW | coal |
| 887 | 2 | Joppa Steam | IL | SRGW | coal |
| 887 | 3 | Joppa Steam | IL | SRGW | coal |
| 887 | 4 | Joppa Steam | IL | SRGW | coal |
| 887 | 5 | Joppa Steam | IL | SRGW | coal |
| 887 | 6 | Joppa Steam | IL | SRGW | coal |
| 892 | 1 | Hennepin Power Station | IL | SRGW | coal |
| 892 | 2 | Hennepin Power Station | IL | SRGW | coal |

| | | | | | |
|---|---|---|---|---|---|
| 898 | 4 | Wood River Power Station | IL | SRGW | coal |
| 898 | 5 | Wood River Power Station | IL | SRGW | coal |
| 963 | 4 | Dallman | IL | SRGW | coal |
| 963 | 31 | Dallman | IL | SRGW | coal |
| 963 | 32 | Dallman | IL | SRGW | coal |
| 963 | 33 | Dallman | IL | SRGW | coal |
| 6017 | 1 | Newton | IL | SRGW | coal |
| 6017 | 2 | Newton | IL | SRGW | coal |
| 8016 | 2 | Factory Gas Turbine | IL | SRGW | oil |
| 55856 | 01 | Prairie State Generating Company | IL | SRGW | coal |
| 55856 | 02 | Prairie State Generating Company | IL | SRGW | coal |
| 1002 | 1A | Connersville Peaking Station | IN | RFCW | oil |
| 1002 | 1B | Connersville Peaking Station | IN | RFCW | oil |
| 1002 | 2A | Connersville Peaking Station | IN | RFCW | oil |
| 1002 | 2B | Connersville Peaking Station | IN | RFCW | oil |
| 1004 | CTG1 | Edwardsport | IN | RFCW | coal |
| 1008 | 2 | R Gallagher | IN | RFCW | coal |
| 1008 | 4 | R Gallagher | IN | RFCW | coal |
| 1040 | 1 | Whitewater Valley | IN | RFCW | coal |
| 1040 | 2 | Whitewater Valley | IN | RFCW | coal |
| 1769 | 5 | Presque Isle | MI | RFCW | coal |
| 1769 | 6 | Presque Isle | MI | RFCW | coal |
| 1769 | 7 | Presque Isle | MI | RFCW | coal |
| 1769 | 8 | Presque Isle | MI | RFCW | coal |
| 1769 | 9 | Presque Isle | MI | RFCW | coal |
| 1831 | 4 | Eckert Station | MI | RFCM | coal |
| 1831 | 5 | Eckert Station | MI | RFCM | coal |
| 1831 | 6 | Eckert Station | MI | RFCM | coal |
| 4259 | 1 | Endicott Generating | MI | RFCM | coal |
| 50835 | 1 | TES Filer City Station | MI | RFCM | coal |
| 50835 | 2 | TES Filer City Station | MI | RFCM | coal |
| 1943 | 2 | Hoot Lake | MN | MROW | coal |
| 1943 | 3 | Hoot Lake | MN | MROW | coal |
| 2835 | 7 | Ashtabula | OH | RFCW | coal |
| 2836 | 10 | Avon Lake Power Plant | OH | RFCW | coal |
| 2836 | 12 | Avon Lake Power Plant | OH | RFCW | coal |
| 2836 | CT10 | Avon Lake Power Plant | OH | RFCW | oil |
| 2837 | 6 | Eastlake | OH | RFCW | oil |
| 2840 | 4 | Conesville | OH | RFCW | coal |
| 2840 | 5 | Conesville | OH | RFCW | coal |
| 2840 | 6 | Conesville | OH | RFCW | coal |

| | | | | | |
|---|---|---|---|---|---|
| 2848 | H-3 | O H Hutchings | OH | RFCW | coal |
| 2848 | H-5 | O H Hutchings | OH | RFCW | coal |
| 2848 | H-6 | O H Hutchings | OH | RFCW | coal |
| 2861 | 1 | Niles | OH | RFCW | coal |
| 2861 | 2 | Niles | OH | RFCW | coal |
| 2861 | CTA | Niles | OH | RFCW | oil |
| 2869 | 1A | West Lorain | OH | RFCW | oil |
| 2869 | 1B | West Lorain | OH | RFCW | oil |
| 2917 | 9 | Hamilton Municipal Power Plant | OH | RFCW | coal |
| 3982 | 1 | Bay Front | WI | MROW | coal |
| 3982 | 2 | Bay Front | WI | MROW | coal |
| 4005 | 3 | French Island | WI | MROW | oil |
| 4005 | 4 | French Island | WI | MROW | oil |
| 4014 | 5 | Wheaton Generating Plant | WI | MROW | oil |
| 4014 | 6 | Wheaton Generating Plant | WI | MROW | oil |
| 4050 | 4 | Edgewater (4050) | WI | MROE | coal |
| 4050 | 5 | Edgewater (4050) | WI | MROE | coal |
| 4072 | 7 | Pulliam | WI | MROE | coal |
| 4125 | 8 | Manitowoc | WI | MROE | coal |
| 4125 | 9 | Manitowoc | WI | MROE | coal |
| 56068 | 1 | Elm Road Generating Station | WI | RFCW | coal |
| 56068 | 2 | Elm Road Generating Station | WI | RFCW | coal |

## Unit Specific Comments

LADCO is supplying the ERTAC Unit Availability file and future year controls files as a descriptor of how we believe units will be operating in 2018. Columns we are most concerned that EPA incorporates in their work in the unit availability file are:

Colum X – Offline start year(this indicated that the state believes that the unit will cease operation on that date/year.

Column BB – New Unit Flag(this indicated that the line represents a new unit coming online as described in Column W. Fuel switches are show by shutting down the original unit and starting up a new unit.

In the Control file Please pay attention to columns G-K for new SO2 controls and N-R for new NOX controls. We believe all these controls should be included in any 2018 estimates.

## State Specific Comments

LADCO is passing along state specific comments. These comments should supersede any statements above for those states.

### Ohio

Ohio has one comment, concerning the utilization of Conesville 5 and 6. These units applied for and received a MATS extension for the installation of controls. I do not anticipate them running less in the future as they will be very well controlled.

### Illinois, Attached as Appendix A.

### Wisconsin, Attached as Appendix B.

# Appendix Q:

# EIA-923 Electric Power Plants Represented in the Generation and Fuel Sources: Ohio 2012 Wind Capacity

**U.S. Department of Energy, The Energy Information Administration (EIA)**
**EIA-923 Electric Power Plants Represented in the Generation and Fuel Data, 2012 Final_Release**
**Sources: EIA-923 and EIA-860 Reports**

| YEAR | EIA Plant Id | Plant Name | Plant State | Sector | Sector Name | North American Industiral Classification System (NAICS) Code | Combined Heat And Power Status (Y = Chp, N= Non-Chp) | Reporting Frequency (Annual Or Monthly) | Nameplate Capacity (MW) |
|---|---|---|---|---|---|---|---|---|---|
| 2012 | 56226 | Bowling Green Wind | OH | 1 | Electric Utility | 22 | N | A | 7.2 |
| 2012 | 57449 | Blue Creek Wind Project | OH | 2 | NAICS-22 Non-Cogen | 22 | N | M | 302 |
| 2012 | 57570 | Cooper Farms VW Project | OH | 6 | Industrial NAICS Non-Cogen | 311 | N | A | 0 |
| 2012 | 57613 | LE Wind Turbine 1 | OH | 6 | Industrial NAICS Non-Cogen | 333 | N | A | 2.5 |
| 2012 | 57620 | Paulding Wind Farm II | OH | 2 | NAICS-22 Non-Cogen | 22 | N | M | 150 |
| | | | | | | | | **Total:** | **461.7** |

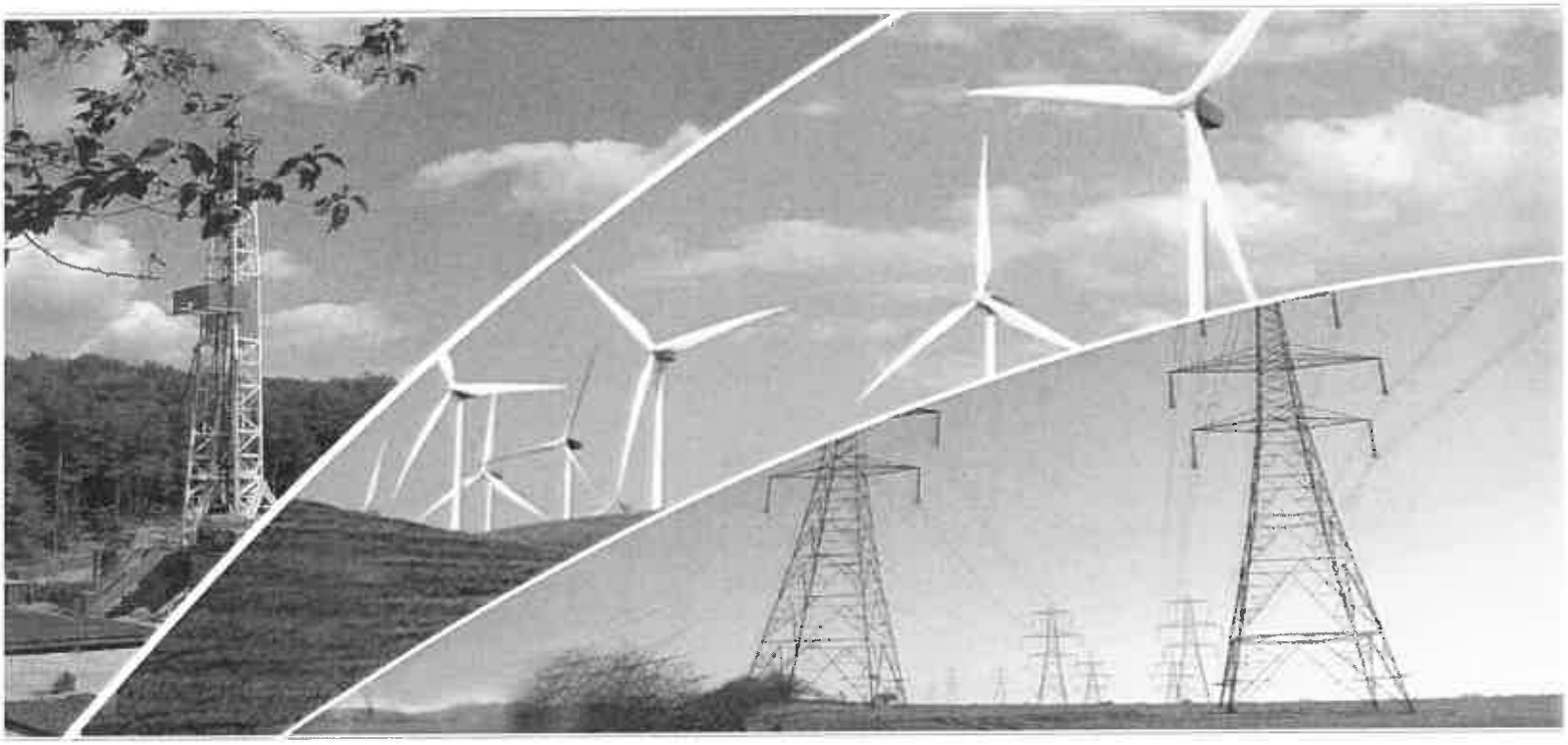
# Appendix R:

# DOE/EIA Annual Energy Outlook 2014 with Projections to 2040

DOE/EIA-0383(2014) | April 2014

# Annual Energy Outlook 2014

## with projections to 2040



Independent Statistics & Analysis
U.S. Energy Information Administration

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AEO2014 is available on the EIA website at [illegible]. Assumptions underlying the projections, tables of regional results, and other detailed results will also be available, at [illegible]. Model documentation reports for the National Energy Modeling System are available at website [illegible] and will be updated for the AEO2014 during 2014.

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# Annual Energy Outlook 2014

## With Projections to 2040

April 2014

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

This publication is on the WEB at:
www.eia.gov/forecasts/aeo

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# Preface

The *Annual Energy Outlook 2014* (AEO2014), prepared by the U.S. Energy Information Administration (EIA), presents long-term annual projections of energy supply, demand, and prices focused on the U.S. through 2040, 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 AEO2014 focuses on five primary cases: a Reference case, Low and High Economic Growth cases, and Low and High Oil Price cases. Results from a number of other alternative cases also are presented, illustrating uncertainties associated with the Reference case projections. EIA published an Early Release version of the AEO2014 Reference case in December 2013.

The report begins with an Executive Summary that highlights key implications of the projections, followed by a Legislation and Regulations section that discusses how recently enacted federal and state legislation and regulations were incorporated in AEO2014, such as: the revised carbon dioxide emissions standards and banking provisions announced by the Regional Greenhouse Gas Initiative in February 2013 [*1*]; updated Renewable Fuel Standard target volumes to reflect actions by the U.S. Environmental Protection Agency to lower the target volume of cellulosic biofuel; and incorporation of modifications to existing state renewable portfolio standards or similar laws since the *Annual Energy Outlook 2013* was released. The Legislation and Regulations section also discusses selected legislative and regulatory issues could have major implications for energy markets and may be enacted in the near future.

The Issues in Focus section contains articles on selected energy topics, including a discussion of the results of two cases based on different assumptions about the future course of existing energy policies: one assumes the elimination of sunset provisions for various energy tax credits that are scheduled to expire under current law; the other assumes—in addition to the elimination of sunset provisions on various tax credits—the extension or expansion of three existing policies: corporate average fuel economy (CAFE) standards, appliance standards, and building code improvements. Other discussions include:

- U.S. tight oil production trends and supply projections based on alternative assumptions and a methodology using well-level data aggregated to the county level
- Potential of liquefied natural gas as a freight locomotive fuel
- Impacts of demographic issues and travel behavior on light-duty vehicle energy demand
- Effects of lower natural gas prices on projected industrial production
- Implications of accelerated power plant retirements
- Renewable electricity projections under alternative assumptions in AEO2014
- Implications of low electricity demand growth.

The Market Trends section summarizes the AEO2014 projections for energy markets by end-use market sector or energy supply source. In some instances, this section also uses alternative cases to illustrate a range of potential outcomes under difference circumstances, highlighting the uncertainty associated with the projections. Complete tables for the five primary cases are provided in Appendixes A through C, and major results from many of the other alternative cases are provided in Appendix D. Complete tables for all the alternative cases are available in a table browser on EIA's website, at http://www.eia.gov/oiaf/aeo/tablebrowser.

AEO2014 projections are based generally on federal, state, and local laws and regulations in effect as of the end of October 2013. 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. In certain situations, however, where it is clear that a law or regulation will take effect shortly after AEO2014 is completed, it may be considered in the projection.

AEO2014 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.

Projections by EIA are not statements of what will happen but of what might happen, given the assumptions and methodologies used for any particular scenario. The AEO2014 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 scenarios with different macroeconomic growth rates, world oil prices, and rates of technology progress. The main cases in AEO2014 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. Many key uncertainties in the AEO2014 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.

## Updated *Annual Energy Outlook 2014* Reference case (April 2014)

The AEO2014 Reference case included as part of this complete report, released in April 2014, was updated from the AEO2013 Reference case released in April 2013. The Reference case was updated to reflect new legislation or regulation enacted since that time or to incorporate modeling changes. Major changes made in the Reference case include:

### Macroeconomic

- Revised U.S. Census Bureau population projections [2]. The population projection for 2040 in the AEO2014 Reference case is almost 6% below the 2040 projection used for the AEO2013 Reference case. Most of the revision in overall population growth results from a lower projection for net international migration, with younger age groups showing the largest differences from the earlier projection. The slower rate of population growth leads to less labor force growth, which contributes to slower GDP growth.

### Residential, commercial, and industrial

- Revised base year residential equipment stocks and energy consumption for space heating, space cooling, and water heating, based on data from EIA's 2009 Residential Energy Consumption Survey (RECS), the most recent data available [3]. Estimates of appliance stocks and energy consumption for several miscellaneous electric loads also were updated, based on a report by Navigant Consulting Inc., to better reflect recent changes and trends in the residential sector [4].
- Updated and expanded representation of miscellaneous electric loads in the commercial sector, as well as personal computers and data center servers, based on the Navigant report, reflecting recent and expected trends in electronics use [5].
- Updated costs and improved representation of residential lighting applications, including wider representation of light emitting diode (LED) lighting and outdoor lighting, based on the 2009 RECS and two U.S. Department of Energy (DOE) reports [6, 7].
- Revised handling of the regional efficiency standard for residential furnaces, based on an ongoing legal appeal of the standard. The regional standard scheduled to take effect in 2013 is not included in AEO2014 because of a court challenge and proposed settlement that would vacate the standard in question and require DOE to develop new standards for residential furnaces.
- Revised commercial capacity factors governing annual usage of major end-use equipment, based on an EIA-contracted analysis.
- Updated manufacturing sector data to reflect the 2010 Manufacturing Energy Consumption Survey (MECS) [8].
- Revised outlook for industrial production to reflect the effects of increased shale gas production and lower natural gas prices, resulting in faster growth for industrial production and energy consumption. The industries primarily affected include energy-intensive bulk chemicals and primary metals, both of which provide products used by the mining and other downstream industries, such as fabricated metals and machinery. The bulk chemicals industry is also a major user of natural gas and, increasingly, hydrocarbon gas liquid (HGL) feedstocks [9].
- Expanded process flow models for the cement and lime industry and the aluminum industry, allowing technologies based on energy efficiency to be incorporated, as well as enhancement of the cement model to include renewable fuels.

### Transportation

- Implemented a new approach to vehicle miles traveled (VMT) projections for light-duty vehicles (LDVs), based on an analysis of VMT by age groups and the aging of the driving population over the course of the projection, which resulted in a significantly lower level of VMT growth after 2018 compared with AEO2013. On balance, demographic trends (such as an aging population and decreasing rates of licensing and travel among younger age groups) combine with employment and income factors to produce a 30% increase in VMT from 2012 to 2040 in AEO2014, compared with 41% growth in AEO2013.
- Added liquefied natural gas (LNG) as a potential fuel choice for freight rail locomotives and domestic marine vessels, resulting in significant penetration of natural gas as a fuel for freight rail (35% of freight rail energy consumption in 2040) but relatively minor penetration in domestic marine vessels (2% of domestic marine energy consumption in 2040).
- Adopted a new approach for estimating freight travel demand by region and commodity for heavy-duty vehicles (HDVs), rail, and domestic marine vessels, as well as updated fuel efficiencies for freight rail and domestic marine vessels.
- Updated handling of flex-fuel vehicle (FFV) fuel shares to better reflect consumer preferences and industry response. FFVs are necessary to meet the renewable fuels standard (RFS), but the phaseout of corporate average fuel economy (CAFE) credits for their sale, as well as limited demand from consumers, reduces their market penetration.
- Revised attributes for battery electric vehicles, including: (1) product availability, (2) electric drive fuel efficiency, and (3) non-battery system costs by vehicle size class, battery size, and added battery cost per kilowatthour based on vehicle power-to-energy ratio for vehicle type—applied to hybrid electric, plug-in hybrid electric, and all-electric vehicles.

### Oil and natural gas production and product markets

- Revised network pricing assumptions based on benchmarking of regional natural gas hub prices to historical spot natural gas prices, using flow decisions based on spot prices, setting variable tariffs based on historical spot natural gas price differentials, and estimating the price of natural gas to the electric power sector off a netback from the regional hub prices [10].

- Allowed secondary flows of natural gas out of the Middle Atlantic region to change dynamically in the model based on relative prices, which enables a larger volume of natural gas from the Middle Atlantic's Marcellus formation to supply neighboring regions.
- Developed the estimated ultimate recovery of tight oil and shale gas on the basis of county-level data [11].
- Updated oil and gas supply module that explicitly reports technically recoverable resources of liquids in natural gas, enabling estimation of dry and wet natural gas.
- Improved representation of the dynamics of U.S. gasoline and diesel exports versus U.S. demand, through adoption of endogenous modeling [12].
- Added representation of the U.S. crude oil distribution system (pipelines, marine, and rail), to allow crude oil imports to go to logical import regions for transport to refineries, which enables crude imports and domestic production to move among refining regions and keeps imports of Canadian crude oil from flowing directly to U.S. Gulf refiners [13].
- Revised production outlook for nonpetroleum other liquids—gas-to-liquids, coal-to-liquids (CTL), biomass-to-liquids, and pyrolysis [14]—with lower production levels than in AEO2013, as more recent experience with these emerging technologies indicates higher costs than previously assumed [15].
- Revised representation of $CO_2$-enhanced oil recovery (EOR) that better integrates the electricity, oil and gas supply, and refining modules [16].

### Electric power sector

- Revised approach to reserve margins, which are set by region on the basis of North American Electric Reliability Corporation/Independent System Operator requirements [17], and to capacity payments, which are calculated as a combination of levelized costs for combustion turbines and the marginal value of capacity in the electricity model.
- Revised handling of spinning reserves, with the required levels set explicitly, depending on the mix of generating technologies used to meet peak demand by region, to allow better representation of capacity requirements and costs in regions or cases with high penetration of intermittent loads.
- Revised assumptions concerning the potential for unannounced retirements of nuclear capacity in several regions to better reflect the impacts of rising operating costs and low electricity prices. Announced nuclear retirements are already incorporated as planned.
- Updated handling of Mercury and Air Toxics Standards (MATS) [18] covering the electric power sector, to reflect potential upgrades of electrostatic precipitators, requirements for plants with dry scrubbers to employ fabric filters, and revised costs for retrofits of dry sorbent injection and fabric filters.
- Updated treatment of the production tax credit (PTC) for eligible renewable electricity generation technologies—consistent with the American Taxpayer Relief Act of 2012 (ATRA) passed in January 2013 [19]—including revision of PTC expiration dates for each PTC-eligible technology, to reflect the concept of projects being declared "under construction" as opposed to being placed "in service," and extension of the expiration date of the PTC for wind generation projects by one year.

Future analyses using the AEO2014 Reference case will start from the version of the Reference case released with this complete report.

# Endnotes

**Links current as of April 2014**


1. Regional Greenhouse Gas Initiative, "Program Review" (New York, New York: February 7, 2013), http://www.rggi.org/docs/ProgramReview/_FinalProgramReviewMaterials/Recommendations_Summary.pdf.
2. The new population projections were released on December 12, 2012. See U.S. Department of Commerce, "U.S. Census Bureau Projections Show a Slower Growing, Older, More Diverse Nation a Half Century from Now" (Washington, DC: December 12, 2012), https://www.census.gov/newsroom/releases/archives/population/cb12-243.html.
3. U.S. Energy Information Administration, "Residential Energy Consumption Survey (RECS): 2009 RECS Survey Data, Public Use Microdata File (Washington, DC: January 2013), http://www.eia.gov/consumption/residential/data/2009/index.cfm?view=microdata.
4. Navigant Consulting, Inc., *Analysis and Representation of Miscellaneous Electric Loads in the National Energy Modeling System (NEMS)* (Washington, DC: May 2013), prepared for U.S. Department of Energy, U.S. Energy Information Administration.
5. Navigant Consulting, Inc., *Analysis and Representation of Miscellaneous Electric Loads in the National Energy Modeling System (NEMS)* (Washington, DC: May 2013), prepared for U.S. Department of Energy, U.S. Energy Information Administration.
6. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *Residential Lighting End-Use Consumption Study: Estimation Framework and Initial Estimates* (Washington, DC: December 2012), http://apps1.eere.energy.gov/buildings/publications/pdfs/ssl/2012_residential-lighting-study.pdf.
7. U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, *2010 U.S. Lighting Market Characterization* (Washington, DC: January 2012), http://apps1.eere.energy.gov/buildings/publications/pdfs/ssl/2010-lm-report-final-jan-2012.pdf.
8. U.S. Energy Information Administration, "Manufacturing Energy Consumption Survey (MECS): 2010 MECS Survey Data" (Washington, DC: March 19, 2013), http://www.eia.gov/consumption/manufacturing/data/2010/.
9. Growing production of wet natural gas and lighter crude oil has focused attention on natural gas liquids (NGL). EIA has developed and adopted a neutral term—"hydrocarbon gas liquid" (HGL)—to equate the supply (*natural gas plant liquids [NGPL] + liquefied refinery gases [LRG]*) and market (*NGL + refinery olefins*) terms. For example, liquefied petroleum gas (LPG) is currently defined by EIA as ethane, propane, normal butane, and isobutane and their olefins (ethylene, propylene, butylene, and isobutylene). This definition is inconsistent with definitions used by other federal agencies, international organizations, and trade groups, in that it implies that all the products are in a liquid state (ethane typically is not) and are used in the same way (higher-value olefins are used differently). Part of the HGL implementation redefines LPG to include only propane, butane, and isobutane and to exclude ethane and refinery olefins. The tables included in AEO2014 have been relabeled to conform to this newly adopted definition.
10. Estimating natural gas prices to the electricity generation sector based on hub prices, rather than the citygate prices as was done in prior years, is a better reflection of current market conditions, in which many large natural gas consumers are outside the citygate.
11. After accounting for infrastructure constraints and general development patterns, oil and natural gas resources in sweet spots are developed earlier than lower quality resources, based on net present value.
12. High U.S. crude oil production and low fuel costs have given U.S. refiners a competitive advantage over foreign refiners, as evidenced by high U.S. refinery utilization and increasing U.S. exports of gasoline and diesel fuel.
13. Oil imports from Canada now are required to go to Petroleum Administration for Defense District (PADD) 2 (Midwest: North Dakota, South Dakota, Nebraska, Kansas, Oklahoma, Minnesota, Iowa, Missouri, Wisconsin, Illinois, Michigan, Indiana, Ohio, Kentucky, and Tennessee); PADD 4 (Rocky Mountain: Montana, Idaho, Wyoming, Utah, and Colorado); and PADD 5 (West Coast: Washington, Oregon, Nevada, California, Arizona, Alaska, and Hawaii) for redistribution through the crude oil distribution infrastructure.
14. Pyrolysis is defined as the thermal decomposition of biomass at high temperatures (greater than 400°F, or 200°C) in the absence of air.
15. EIA undertook detailed assessments of these technologies in order to characterize key parameters considered in the model, such as capital cost, contingency factors, construction time, first year of operation, plant life, plant production capacity, efficiency, and feedstock and other operating costs.
16. When considering $CO_2$ EOR, the oil and gas supply module assesses a location and the availability and price of $CO_2$ from power plants and CTL facilities. The electric power plants now consider the market size and prices for $CO_2$ captured. The refining module assesses a location and the availability and price of $CO_2$ from CTL facilities. The power sector now assesses opportunities for plants equipped with carbon capture and storage, as the $CO_2$ produced at those facilities can be used for EOR operations. This enables the model to solve dynamically for the capture of $CO_2$ and the production of oil from anthropogenic $CO_2$ EOR.

17. North American Electric Reliability Corporation, *2013 Summer Reliability Assessment* (Atlanta, GA: May 2013), http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2013SRA_Final.pdf (password required).

18. U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards (MATS)," http://www.epa.gov/mats.

19. U.S. House of Representatives, 112th Congress, Public Law 112-240, "American Taxpayer Relief Act of 2012," Sections 401-412 (Washington, DC: January 2, 2013), http://www.epa.gov/fdsys/pkg/PLAW-112publ240/pdf/PLAW-112publ240.pdf.

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# Executive summary

Projections in the U.S. Energy Information Administration's *Annual Energy Outlook 2014* (AEO2014) focus on the factors that shape the U.S. energy system over the long term. Under the assumption that current laws and regulations remain unchanged, the AEO2014 Reference case provides a basis for examination and discussion of energy production, consumption, technology, and market trends and the direction they may take in the future. AEO2014 also includes alternative cases that explore important areas of uncertainty for markets, technologies, and policies in the U.S. energy economy (see Appendix E for discussion of detailed case assumptions). Many of the implications of the alternative cases are discussed in the Issues in Focus section of AEO2014.

Key results highlighted in the AEO2014 Reference and alternative cases include:

- Growing domestic production of natural gas and oil continues to reshape the U.S. energy economy, largely as a result of rising production from tight formations, but the effect could vary substantially depending on expectations about resources and technology.
- Industrial production expands over the next 10 to 15 years as the competitive advantage of low natural gas prices provides a boost to the industrial sector with increasing natural gas use.
- There is greater upside uncertainty than downside uncertainty in oil and natural gas production; higher production could spur even more industrial growth and lower the use of imported petroleum.
- Improvement in light-duty vehicle (LDV) efficiency more than offsets modest growth in vehicle miles traveled (VMT) that reflects changing driving patterns, leading to a sharp decline in LDV energy use.
- Evolving natural gas markets spur increased use of natural gas for electricity generation and transportation, as well as expanded export opportunities.
- Improved efficiency of energy use in the residential and transportation sectors and a shift away from more carbon-intensive fuels such as coal for electricity generation help to stabilize U.S. energy-related carbon dioxide ($CO_2$) emissions.

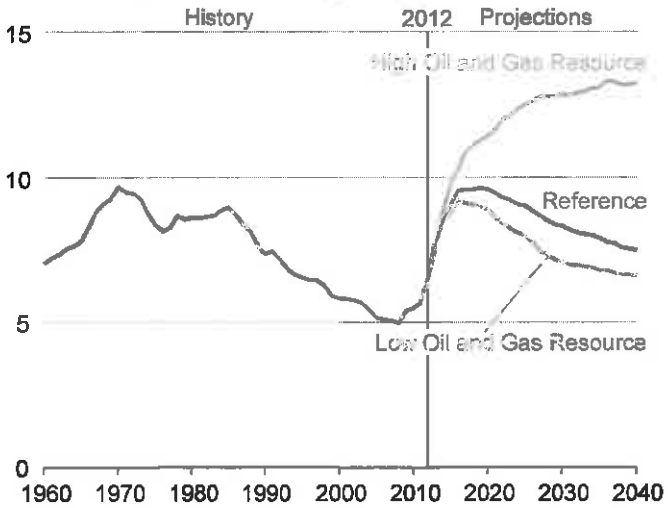
## Expected gains in tight oil production drive projected growth in total petroleum and other liquids production

Growth in crude oil production from tight oil and shale formations supported by identification of resources and technology advances have supported a nearly fourfold increase in tight oil production from 2008, when it accounted for 12% of total U.S. crude oil production, to 2012, when it accounted for 35% of total U.S. production. Total projected U.S. crude oil production in the AEO2014 Reference case reaches 9.6 million barrels per day (MMbbl/d) in 2019—3.1 MMbbl/d more than in 2012. Over the same period, tight oil production grows by 2.5 MMbbl/d, to 4.8 MMbbl/d or 50% of the national total.

In the Reference case, tight oil production begins to slow after 2021, contributing to a decline in total U.S. oil production through 2040. However, tight oil development is still at an early stage, and the outlook is uncertain. Changes in U.S. crude oil production depend largely on the degree to which technological advances allow production to occur in potentially high-yielding tight and shale formations. They also depend on the assumed estimated ultimate recovery (EUR) for wells drilled in those formations, in addition to assumptions about well spacing and production patterns. To address these uncertainties, AEO2014 includes High Oil and Gas Resource and Low Oil and Gas Resource cases (Figure ES-1). In the High Oil and Gas Resource case, tight oil production reaches 8.5 MMbbl/d in 2035 (compared to 3.7 MMbbl/d in the Reference case), with total U.S. crude oil production reaching 13.3 MMbbl/d in the following year (compared to 7.8 MMbbl/d in the Reference case).

A comparison of the Reference case and High Oil and Gas Resource case demonstrates the significant impact that technological development and productivity gains in tight oil plays can have on net imports of crude oil and petroleum products. In the Reference case, the share of net crude oil and petroleum product imports as a percentage of total U.S. product consumed declines from 41% in 2012 to 25% in 2016, remains close to that level for several years, and then rises to 32% in 2040 (Figure ES-2). In the High Oil and Gas Resource case, domestically produced crude oil displaces more expensive imported crude at domestic refineries, and U.S. finished petroleum products become more competitive worldwide. The share of total U.S. product consumed represented by net crude oil and petroleum product imports in the High Oil and Gas Resource case declines to 15% in 2020 and continues to fall through 2040. The United States becomes a net exporter of crude oil and petroleum products at the end of the projection period.

Figure ES-1. U.S. crude oil production in three cases, 1960-2040 (million barrels per day)




Among the most uncertain aspects of this analysis are the potential effects of alternative resource and technology assumptions on the global market for liquid fuels, which is highly integrated. Regardless of how much the United States reduces its reliance on imported liquids, consumer prices will not be insulated from global oil prices set in global markets

for crude oil and petroleum products. Strategic choices made by leading oil-exporting countries could result in U.S. price and quantity changes that differ significantly from those presented in this outlook.

### U.S. industrial production is spurred by abundant and relatively inexpensive natural gas

The AEO2014 Reference case projects robust growth in industrial production, with the manufacturing sector benefitting from abundant and relatively inexpensive natural gas, especially in the first 15 years of the projection. Low natural gas prices and increased availability of natural gas and related resources such as hydrocarbon gas liquids (HGL) benefit the U.S. industrial sector in multiple ways. Natural gas is used as a fuel to produce heat and to generate electricity and, along with HGL products, is also used as a feedstock to produce chemicals, pharmaceuticals, and plastics. In addition, with generally lower energy prices resulting in more rapid economic growth, demand for industrial products increases.

Bulk chemicals account for much of the increased growth in manufacturing output in the Reference case (Figure ES-3). Industrial production of bulk chemicals, which also benefits from increased supply of HGL, grows by 3.4%/year from 2012 to 2025 in the AEO2014 Reference case. The near-term competitive advantage diminishes over time, however, and growing competition from abroad slows U.S. output growth after 2030 as domestic natural gas becomes less cost-advantaged compared with prices at other locations, resulting in increased competition from newer facilities that are developed abroad.

The higher level of industrial production leads to growth in natural gas consumption in the U.S. industrial sector, from 8.7 quadrillion British thermal units (Btu) in 2012 to 10.6 quadrillion Btu in 2025 in the Reference case. Most of the increase in industrial natural gas demand is the result of output growth in the manufacturing sector. Energy-intensive industries with high rates of growth include paper products, food products, bulk chemicals, and metal-based durables.

Different assumptions about economic growth or about oil and gas resources and technology result in large variations in industrial output, with bulk chemicals showing more variation in the High and Low Oil and Gas Resource cases and the rest of the manufacturing sector showing more variation in the High and Low Economic Growth cases. Output from the bulk chemicals industry is more responsive to variations in energy prices than is output from the rest of the industrial sector, and shipments continue to grow after 2035 in the High Oil and Gas Resource case, as indicated in Figure ES-3.

### Transportation energy use continues to decline, with light-duty vehicles sharply reducing gasoline consumption due to fuel efficiency and changing usage patterns

Fuel use in the U.S. transportation sector has changed fundamentally in the past several years. In the AEO2014 Reference case, the factors contributing to declining light-duty vehicle (LDV) energy use continue and intensify, resulting in declines in motor gasoline consumption over the projection period.

LDV fuel efficiency is driven by increasingly stringent regulatory standards. In the Reference case, the fuel efficiency of the LDV stock in miles per gallon (mpg), excluding light-duty commercial trucks, increases by 2%/year to 37.2 mpg in 2040 from 21.5 mpg in 2012. While motor gasoline remains the dominant fuel, growing market penetration of diesel, biofuels, hybrid-electric, and plug-in electric systems gradually reduces its share of the LDV fuel market.

AEO2014 includes a new demographic profile of driving behavior by age and gender. Total vehicle miles traveled (VMT) increases at an average annual rate of 0.9% from 2012 to 2040, due to changes in driving behavior that are related to age and gender demographics. Older drivers increase as a proportion of the U.S. driving population, with their higher licensing rates but lower-than-average mileage

Figure ES-2. Net import share of U.S. petroleum and other liquids consumption in three cases, 1990-2040 (percent)

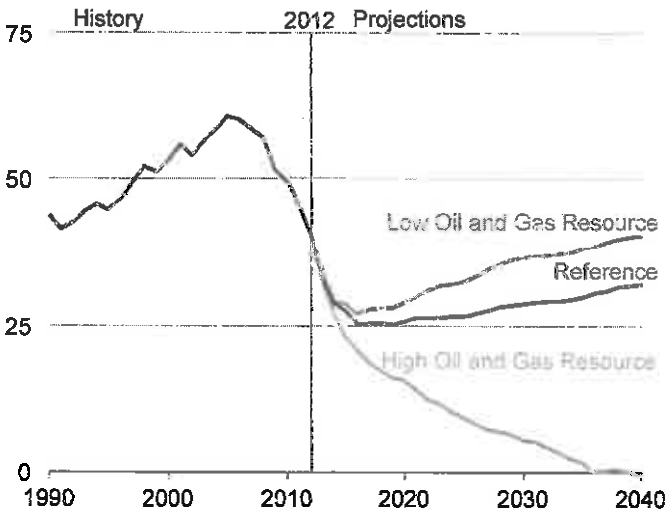
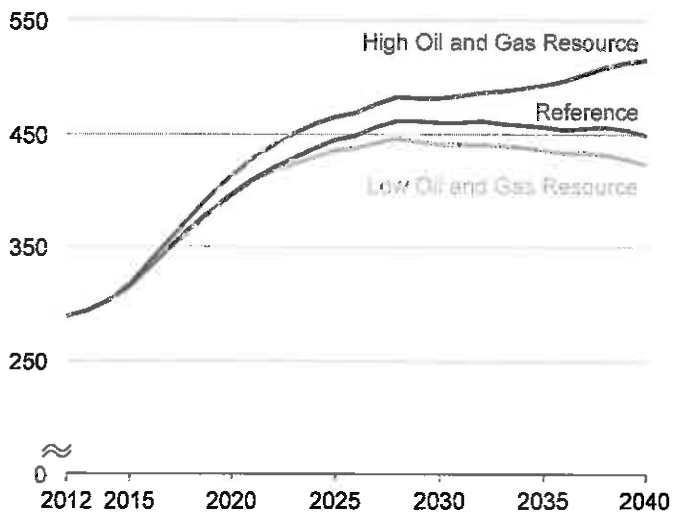



Figure ES-3. Value of shipments of bulk chemicals in three cases, 2012-40 (billion 2005 dollars)



per capita contributing to a gradual increase in total VMT. However, rising fuel economy more than offsets the modest growth in VMT, and energy consumption by LDVs declines in the Reference case from 8.4 MMbbl/d in 2012 to 6.4 MMbbl/d in 2040.

The importance of demographic changes for VMT and transportation energy consumption is highlighted by AEO2014 alternative cases in which variations in these assumptions result in higher or lower fuel use (Figure ES-4). In a High VMT case, U.S. LDVs consume 5% more energy by 2040, while in a Low VMT case they consume 18% less energy than in the Reference case. This variation in projected energy demand from the transportation sector has further effects on other key energy sector indicators, including fuel use, imports, and $CO_2$ emissions.

### Abundant supply of natural gas spurs greater use for electricity generation and transportation

Natural gas is an attractive fuel for new generating capacity. In some regions, natural gas-fired generation captures markets formerly supplied by coal-fired and nuclear plants, and by 2035 natural gas surpasses coal as the nation's largest source of energy for electricity generation (including the power sector and end-use sector generation) in the Reference case (Figure ES-5). In the first decade of the projection, growth in electricity generation from renewables tends to be largely policy-driven. However, as Reference case natural gas prices rise and the capital costs of renewable technologies—particularly wind and solar—decrease over time, renewable generation becomes more competitive, accounting for 16% of total electricity generation in 2040.

If additional existing coal-fired and nuclear generating capacity were retired, natural gas-fired generation could grow more quickly to fill the void. In recent years, the number of coal and nuclear plant retirements has increased, in part due to a decline in profitability as low natural gas prices have influenced the relative economics of those facilities. The Accelerated Coal Retirements case assumes that both coal prices and coal plant operating costs are higher than in the Reference case, leading to additional coal plant retirements. In this case, natural gas-fired generation overtakes coal-fired generation in 2019, and by 2040 the natural gas share of total generation reaches 43%. In the Accelerated Coal and Nuclear Retirements case, the natural gas share of total generation in 2040 grows to 47%. In both cases, renewable generation also increases relative to the Reference case. However, barring a breakthrough in electricity storage or related technologies, renewable technologies cannot fully replace the baseload generation lost as a result of coal and nuclear plant retirements, and total additions of natural gas-fired combined-cycle capacity in these cases are 32% to 50% higher than in the Reference case over the projection period.

Freight rail is considered a potential additional source of natural gas use in AEO2014. Any transition from diesel to natural gas as a fuel for freight locomotives will depend on economics, infrastructure needs, and railroads' decisions with regard to risk and uncertainty. For AEO2014, alternative cases were developed that anticipate varying degrees of natural gas penetration into the U.S. freight rail market. In the High Rail LNG case, natural gas is used to meet nearly all freight rail energy demand by 2040, while in the Reference case it gains 35% of the rail fuel market by that date. However, because the transportation sector is a relatively small consumer of natural gas compared to other sectors, the seemingly dramatic fuel switch from the perspective of freight rail is only a minor change in overall U.S. natural gas consumption.

### A shift away from more carbon-intensive fuels for electricity generation helps to stabilize energy-related carbon dioxide emissions

In the AEO2014 Reference case, total U.S. energy-related emissions of $CO_2$ remain below the 2005 level in every year through 2040. In the Reference case, $CO_2$ emissions from the U.S. industrial sector exceed emissions from the transportation sector

Figure ES-4. U.S. light-duty vehicle energy use in three cases, 1995-2040 (million barrels of oil equivalent per day)

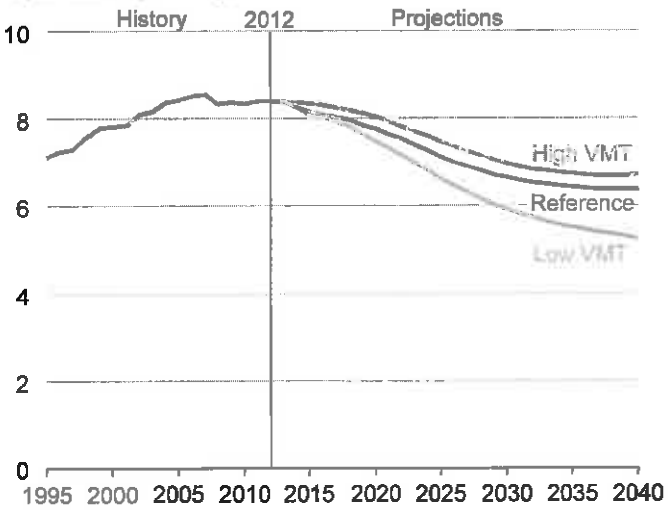
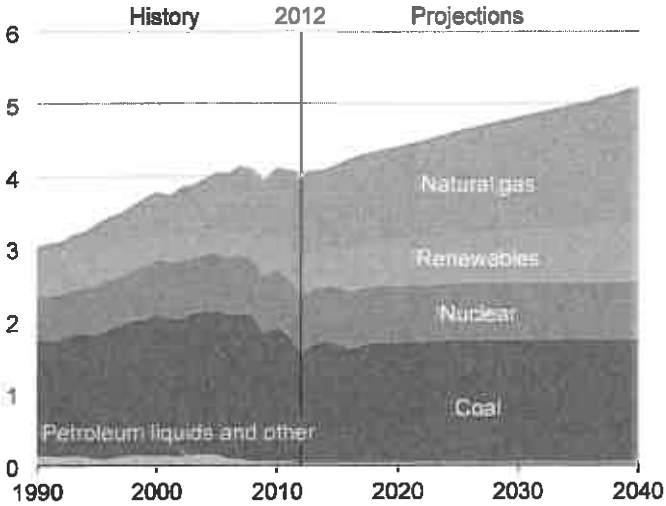



Figure ES-5. Electricity generation by fuel in the Reference case, 1990-2040 (trillion kilowatthours)



beginning in 2024, for the first time since the late 1990s, as new fuel economy standards, biofuel mandates, and shifts in consumer behavior result in declining or stable transportation sector emissions from 2012 through 2033. After 2033 they begin to rise again, with freight transport increasing the demand for diesel, while demand for motor gasoline declines. In the electric power sector, emissions from coal combustion remain below 2011 levels through 2040 as more power plants are fueled by lower-carbon fuels, including natural gas and renewables.

$CO_2$ emissions in the electric power sector are dependent on the overall level of demand for electricity, as well as the mix of generating technologies used to satisfy that demand. In the Reference case, the average emission rate per kilowatthour of generation declines over time, primarily because the coal-fired share of total generation declines and is replaced predominantly with natural gas-fired generation, which is less carbon intensive than coal. In addition, the combined share of generation from nuclear and renewable fuels is gradually increasing throughout the projection, maintaining a generally consistent contribution of carbon-free generation resources. As a result, although generation in the electric power sector increases by 25% from 2012 to 2040, the sector's $CO_2$ emissions increase by only 11% over the same period. In most of the alternative cases, a decline in demand results in a greater decline in fossil-fueled generation and $CO_2$ emissions, as less efficient oil, coal, and natural gas plants reduce output or are retired. For example, in the Low Electricity Demand case, with retail electricity sales in 2040 about the same as in 2012, generation in the electric power sector is 20% lower, and $CO_2$ emissions are 22% lower, than projected in the Reference case.

$CO_2$ emissions in the power sector are highly sensitive to the relative generation shares of different fuel types, and larger shifts away from fossil fuels lead to declining emissions. While the retirement of coal-fired plants in the near term contributes to lower levels of $CO_2$ emissions, in the Accelerated Coal Retirements case, where coal retirements through 2040 are more than double those in the Reference case, $CO_2$ emissions decline by 11% from 2012 levels and are 20% below Reference case levels in 2040.

In general, growth of renewable generation is associated with a reduction in $CO_2$ emissions in the electric power sector. In the Low Renewable Technology Cost case, nonhydropower renewable generation grows at an average annual rate of 4.7% from 2012 to 2040 (Figure ES-6), compared to 3.2% in the Reference case, and electric power sector $CO_2$ emissions in 2040 are about 4% below the Reference case level. When growth in nonhydropower renewable generation is coupled with electricity demand growth that exceeds that in the Reference case, the impact on emissions may be more ambiguous. In the High Economic Growth case, although nonhydropower renewable generation grows by an average of 4.1%/year from 2012 to 2040, total electricity demand grows by 1.2%/year and electric power sector $CO_2$ emissions in 2040 are about 4% higher than in the Reference case.

In most cases that include high levels of nonhydropower renewable generation, electric power sector $CO_2$ emissions still increase slightly, if not as rapidly as in the Reference case, between 2012 and 2040, reflecting factors such as generation subsidies that reduce the cost of electricity and its price, raising demand. Cases that place a fee on $CO_2$ emissions throughout the energy sector, starting at either $10 or $25/ton and rising at a rate of 5%/year thereafter (the GHG10 and GHG25 cases), and a case that combines the GHG10 case with the High Oil and Gas Resource case (the GHG10 and Low Gas Prices case) are notable exceptions. In those cases, because the additional cost of operating generators that use fossil fuels results in both a decrease in overall electricity demand and significant substitution of nonhydropower renewable energy sources for fossil-fueled generation, total electric power sector $CO_2$ emissions in 2040 are between 36% and 82% below the Reference case total of 2,259 million metric tons, respectively, and total energy-related $CO_2$ emissions from all sources in 2040 are between 15% and 36% below the Reference case total of 5,599 million metric tons (Figure ES-7).

Figure ES-6. Nonhydropower renewable electricity generation in eight cases, 2005–40 (billion kilowatthours)

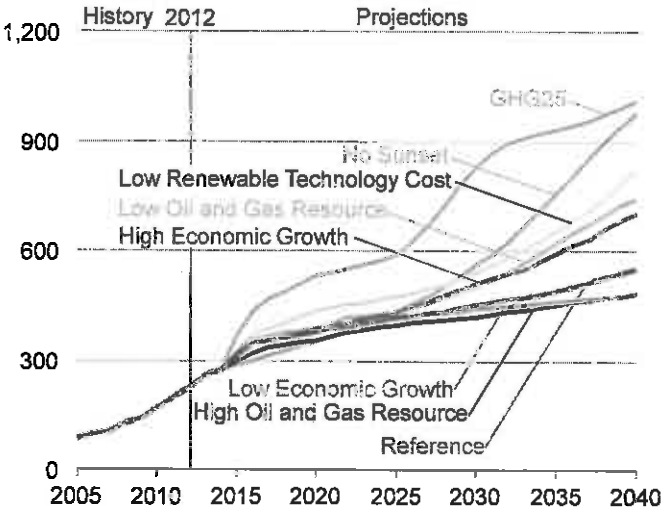
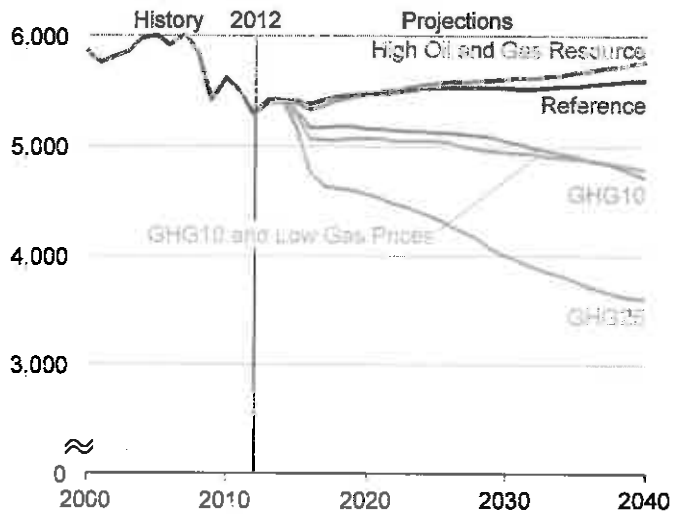



Figure ES-7. Energy-related carbon dioxide emissions in five cases, 2000–40 (million metric tons)



# Figure and table sources

**Links current as of April 2014**

**Figure ES-1. U.S. crude oil production in three cases, 1960-2040: History:** U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

**Figure ES-2. Net import share of U.S. petroleum and other liquids consumption in three cases, 1990-2040:** U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

**Figure ES-3. Shipments of bulk chemicals in three cases, 2012-40:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

**Figure ES-4. U.S. light-duty vehicle energy use in three cases, 1995-2040: History:** U.S. Department of Transportation, Federal Highway Administration, National Household Travel Survey, http://nhts.ornl.gov/download.html. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

**Figure ES-5. Electricity generation by fuel in the Reference case, 1990-2040: History:** U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

**Figure ES-6. Nonhydropower renewable electricity generation in eight cases, 2005-40: History:** U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, CO2FEE25.D011614A, NOSUNSET.D121713A, LCR_2014.D120613A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

**Figure ES-7. Energy-related carbon dioxide emissions in five cases, 2000-40: History:** U.S. Energy Information Administration, *Monthly Energy Review,* September 2013, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, HIGHRESOURCE.D112913B, CO2FEE10.D011614A, CO2FEE25.D011614A, and CO2FEE10HR.D011614A.

# Legislation and regulations

## Introduction

The *Annual Energy Outlook 2014* (AEO2014) generally represents current federal and state legislation and final implementation of regulations as of the end of October 2013. The AEO2014 Reference case assumes that current laws and regulations affecting the energy sector are largely unchanged throughout the projection period (including the implication that laws that include sunset dates are no longer in effect at the time of those sunset dates) [1]. The potential impacts of proposed legislation, regulations, or standards—or of sections of authorizing legislation that have been enacted but are not funded, or for which parameters will be set in a future regulatory process—are not reflected in the AEO2014 Reference case, but some are considered in alternative cases. This section summarizes federal and state legislation and regulations newly incorporated or updated in AEO2014 since the completion of the *Annual Energy Outlook 2013* (AEO2013). It also summarizes selected rules and regulations that have been proposed recently and have the potential to affect the projection significantly.

Examples of federal and state legislation and regulations incorporated in the AEO2014 Reference case, or whose handling has been modified, include:

- Incorporation of the revised emissions standards and banking provisions for carbon dioxide ($CO_2$) announced by the nine-state Regional Greenhouse Gas Initiative in February 2013, which lowered the program's emissions cap by 45% starting in 2014 [2].
- Updated handling of the mandated volume for biofuels established for the renewable fuel standard (RFS) by the Energy Policy Act of 2005 (EPACT2005) [3] and expanded by the Energy Independence and Security Act of 2007 (EISA2007) [4] to reflect final and proposed actions by the U.S. Environmental Protection Agency (EPA) to set obligations for both cellulosic biofuels and total renewable fuels below the legislated targets, using the discretion allowed by the law.
- Incorporation of modifications to existing state Renewable Portfolio Standard (RPS) or similar laws to reflect recent modifications to existing programs in Colorado, Connecticut, Maryland, Montana, Minnesota, Nevada, New Mexico, and Washington [5]. The changes that were enacted affect some aspects of the laws and implementing regulations, but in general they do not have significant substantive effects on the representation of the RPS programs in AEO2014.

There are many other pieces of legislation and regulation that might be enacted in the not-too-distant future, and some laws include sunset provisions that may be extended. However, it is difficult to discern future outcomes. Even in situations where existing legislation contains provisions to allow revision of implementing regulations, those provisions may not be exercised consistently. Many pending provisions are examined in alternative cases included in AEO2014 or in other analyses completed by the U.S. Energy Information Administration (EIA). In addition, at the request of both federal agencies and Congress, EIA has regularly examined the potential implications of other possible energy options in special analyses that can be found on the EIA website at http://www.eia.gov/analysis/reports.cfm?t=138.

## LR1. Recent environmental regulations in the electric power sector

Several environmental rules recently implemented at the federal and state levels affect the AEO2014 projections for the electric power sector. While not considered in the AEO2014 Reference case, the EPA is also currently in the process of developing new rules to address electric power plant air emissions, the impact of cooling water intake systems on aquatic life, and coal ash disposal methods. New rules that may be promulgated could have significant impacts on the projected fuel mix for electric power generation. The following discussion summarizes programs and rules included in the AEO2014 Reference case.

### Recent regional policy modifications

The Regional Greenhouse Gas Initiative (RGGI) is a regional cap-and-trade program for $CO_2$ emissions that applies specifically to fossil-fueled electric power plants larger than 25 megawatts (MW) located in each of the nine participating Northeastern states [6]. When it took effect in 2009, RGGI became the first mandatory market-based (cap-and-trade) $CO_2$ reduction program in the United States. The cap was tightened primarily because actual $CO_2$ emissions in the region since the start of the program in 2009 have been roughly 35% below the cumulative cap. The lower level of emissions is attributed primarily to historically low natural gas prices, which have shifted a large share of electricity generation in the region toward natural gas, and to lower overall electricity demand.

$CO_2$ emissions in the RGGI region comprised only 4% of the total emissions from the electric power sector in the United States in 2012. RGGI is one of the two legally mandated $CO_2$ cap-and-trade reduction programs in the United States, the other being the California cap-and-trade program that was an outgrowth of California's Assembly Bill 32, the Global Warming Solutions Act of 2006 (AB 32) [7].

In 2005, when $CO_2$ emissions in the participating states reached their annual peak, coal comprised 23%, natural gas 25%, and petroleum 12% of the regional generation mix. By 2012, coal's share had declined to 9%, the natural gas share had risen to 44%, and the petroleum share had fallen below 1%.

At the same time that the shift in fuels for electricity generation has lowered the carbon intensity of electricity generation in the region, demand for electricity in the Northeast has been flat or declining. Average annual retail electricity sales in the nine participating states from 2009 through 2012 were 6% below the annual sales in 2005.

Despite the reduction in the cap beginning in 2014, it remains to be seen whether the updated program caps will result in significant emissions reductions compared to the outcomes that might occur absent the new caps. $CO_2$ emissions in 2012 in the participating states were still only 92 million short tons, close to the 2014 target cap of 91 million short tons. However, the cap is designed to tighten annually through 2020. In the first half of 2013, $CO_2$ emissions from coal-fired generation were up both in the RGGI region and nationally compared with 2012 levels, which indicates that the revised cap could become more binding in the future.

Because of a surplus of allowances during the initial years of RGGI, the $CO_2$ value of the allowances remained close to the program's price floor of $1.93/ton of $CO_2$ allowed in each quarterly auction. The value of allowances increased to $3.00/ton of $CO_2$ in the latest auction, as market participants may be anticipating a rise in the future value of allowances. RGGI states use allowance revenues for a variety of programs that support cleaner generation and/or energy efficiency programs that reduce demand. Unless the programs supported by RGGI auction revenues are funded at the same level using other funding sources in the absence of RGGI, they will provide a tangible incremental reduction in emissions.

The RGGI program update grants the ability for previously unused allowances from the early years of the program to be saved and applied after 2014, as limits become more stringent—a strategy often referred to as "banking allowances." Additional flexibility exists in the program through the recently created Cost Containment Reserve, which effectively creates a price ceiling for allowances. When the price hits a given level, program participants can purchase a set level of allowances at a defined fixed price. This ceiling is intended to prevent allowance prices from rising above defined levels. The price trigger starts at $4/ton of $CO_2$ in 2014 and rises to $10/ton of $CO_2$ in 2017.

The program also allows for the limited use of $CO_2$ offsets as a compliance option. RGGI program participants are permitted to cover 3.3% of their emissions using offsets. Although the RGGI caps have been lowered, it remains to be seen how much the new caps will affect generation choices and related emissions.

### Recent federal environmental regulations modeled in AEO2014

The Mercury and Air Toxics Standards (MATS) [8] requires fossil-fuel steam electric generators to meet limits based on maximum achievable control technologies (MACT) to control emissions of acid gases, toxic metals, and mercury. The standards will take effect by April 2015 for electric generation units with capacities greater than 25 MW. The rule allows for state environmental permitting agencies to grant one-year compliance extensions, which AEO2014 assumes will be granted, and all applicable units must begin to comply with the rule at the beginning of 2016. AEO2014 assumes that, in order to comply with the rule, all qualifying coal-fired power plants will be equipped with either flue gas desulfurization (FGD) scrubbers or dry sorbent injection (DSI) systems and activated carbon injection if warranted for mercury control. The control equipment needed to reduce mercury is specific to each plant configuration and coal type [9].

MATS is currently being challenged in the U.S. Court of Appeals for the District of Columbia Circuit in *White Stallion Energy Center et al. v. U.S. EPA* [10]. The case was heard in December 2013, and a decision is expected in the spring of 2014.

The Clean Air Interstate Rule (CAIR) [11] is a cap-and-trade program aimed at reducing emissions of sulfur dioxide ($SO_2$) and nitrogen oxides ($NO_X$) from fossil-fueled power plant units with capacities greater than 25 MW in 27 eastern states and the District of Columbia. The emissions caps went into effect in 2009 for $NO_X$ and in 2010 for $SO_2$. Both caps are scheduled to be tightened in 2015. AEO2014 includes the CAIR cap-and-trade program for the applicable regions. The FGD scrubbers or DSI systems required by MATS result in $SO_2$ emissions falling to levels lower than the CAIR cap. Therefore, after MATS is in full effect starting in 2016, $SO_2$ emissions decline significantly below the CAIR cap, essentially making CAIR's $SO_2$ cap nonbinding [12].

CAIR was reinstated after the Cross-State Air Pollution Rule (CSAPR) was vacated by the U.S. Court of Appeals for the District of Columbia Circuit in August 2012 [13]. However, the U.S. Supreme Court agreed in June 2013 to review the D.C. Circuit Court's decision and heard the case in December 2013 [14]. A court decision is expected in the spring of 2014. If the Supreme Court reverses the D.C. Circuit Court's ruling, CSAPR will replace CAIR.

## LR2. Handling of the Renewable Fuels Standard in AEO2014

The Renewable Fuel Standard (RFS) was established by the Energy Policy Act of 2005 [15] and was expanded by the Energy Independence and Security Act of 2007 (EISA2007) [16]. It requires the EPA to set requirements for the renewable content of gasoline and diesel fuel. Refiners and importers of gasoline and diesel fuel are obligated to blend renewable fuels in proportion to the volumes of gasoline and diesel fuel sold. There are four interrelated requirements, for cellulosic biofuels, biomass-based diesel, advanced biofuels, and total renewable fuels. Compliance with the RFS is tracked via Renewable Identification Numbers (RINs), which are generated when eligible biofuels are produced or imported and conveyed with the physical volume of renewable fuel through subsequent sales until they are blended with a petroleum product. Once the fuel is blended, the RINs can be separated from the physical volumes and "retired"—that is, turned in to the EPA to demonstrate compliance. RINs also can be sold or saved ("banked") for compliance either in the year they were generated or in the following year.

EPA sets the RFS target volumes every year in reference to legislated targets in EISA2007, public comments, and input from other government agencies. Since the expansion of the RFS program for the 2009 compliance year, the EPA has adhered to the legislated volumes of total renewable fuel, advanced biofuel, and biomass-based diesel but has often set the requirement for

cellulosic biofuel well below the legislated target, given the very low commercial availability of cellulosic biofuel. EISA2007 also included new Corporate Average Fuel Economy (CAFE) standards, which have played and will continue to play a role in reducing gasoline consumption. Declines in gasoline consumption reduce the number of gallons of ethanol that can be used in E10, a fuel containing 10% ethanol by volume that is compatible with all existing gasoline-powered vehicles. EPA announced in its 2013 RFS final rule that it expected to reduce the total renewable fuel and advanced biofuel obligations to levels below the statutory levels for 2014, in order to allow the ethanol share of the gasoline pool to remain close to 10%.

The AEO2014 projections for quantities and costs of gasoline, diesel, and other liquid fuels are handled by the National Energy Modeling System's Liquid Fuels Market Model (LFMM), which includes a representation of the U.S. petroleum refining system, biofuels production, and marketing of liquid fuels to end users. The modeling structure allows for additions and adjustments in the liquid fuels supply chain in order to meet new demand or to comply with changing product specifications. A variety of feedstocks and technologies for the production of RIN-eligible renewable fuels can be represented, depending on the market and regulatory conditions (including future product specifications for gasoline and diesel fuel) for each AEO2014 case.

AEO2014 assumes that cellulosic fuel production and requirements will grow gradually from current low levels. For biomass-based diesel, the assumed production requirement is constant at 1.92 billion ethanol-equivalent gallons. The advanced biofuels production requirement, on the other hand, decreases by 425 million gallons from 2014 to 2015.

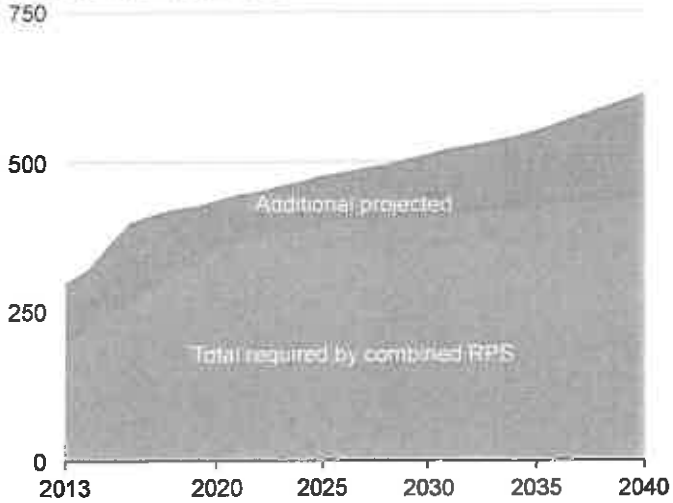
The reintroduction of the $1.00-per-gallon biodiesel blending tax credit in 2013 incentivized biodiesel production above the RFS level. That tax credit sunset at the end of 2013, and the AEO2014 Reference case does not assume that it is reinstated. The California Low Carbon Fuels Standard is expected to draw more sugarcane ethanol into California, generating more advanced RINs. After 2015, the total quantity of advanced biofuels needed to meet the RFS is assumed to increase only slowly, remaining well below the legislated target of 21 billion gallons in 2022. The total biofuels production requirement was set at 15.2 billion gallons in 2014 to reflect the gasoline market's limited ability to absorb additional ethanol in the near term. The total renewable fuels requirement is also assumed to grow slowly and remains well below the legislated target of 36 billion gallons in 2022.

### LR3. State renewable energy requirements and goals: update through 2013

To the extent possible, AEO2014 reflects state laws and regulations in effect at the end of October 2013 that require the addition of renewable generation or capacity by utilities doing business in the state [17] to meet RPS requirements. The projection does not include laws and regulations with either voluntary goals or targets that can be substantially satisfied with nonrenewable resources. In addition, the projection does not account for fuel-specific provisions—such as those for solar and offshore wind energy—as distinct targets. Where applicable, such distinct targets (sometimes referred to as "tiers," "set-asides," or "carve-outs") may be subsumed into the broader targets, or they may not be included in the model because they could be met with existing capacity and/or projected growth based on modeled economic and policy factors.

States are projected to meet their ultimate RPS targets in the AEO2014 Reference case. The RPS compliance constraints in most regions are approximated, however, because National Energy Modeling System is not a state-level model, and each state generally represents only a portion of one of the NEMS electricity regions. In general, EIA has confirmed the states' requirements through original legislative or regulatory documentation, although the Database of State Incentives for Renewables & Efficiency was also used to support those efforts [18]. The aggregate RPS requirement for various mandatory state programs, as modeled for AEO2014, is shown in Figure LR3-1. In 2025, the targets account for slightly less than 10% of U.S. electricity sales.

Figure LR3-1. Total qualifying renewable generation required for combined state renewable portfolio standards and projected total achieved, 2013-40 (billion kilowatthours)




At present, most states are meeting or exceeding their required levels of renewable generation, based on qualified generation or purchase of renewable energy credits [19]. A number of factors have helped to create an environment favorable for RPS compliance, including:

- A surge of new RPS-qualified generation capacity timed to take advantage of federal incentives.
- Significant reductions in the cost of wind, solar, and other renewable technologies.
- Generally slower growth of electricity sales.
- Complementary state and local policies that either reduce the cost (for example, equipment rebates) or increase the revenue streams (for example, net metering) associated with RPS-eligible technologies.

EIA projects that, overall, RPS-qualified generation will continue to meet or exceed aggregate mandatory targets for state RPS programs through 2040, as shown in Figure LR3-1.

The aggregate near-term surplus of qualified generation is supported by projected near-term renewable capacity additions but declines slightly as growth in renewable capacity slows toward the end of this decade and RPS targets catch up with supply. The surplus widens again in the final two decades of the projection period, as renewable generation technologies become increasingly competitive with conventional generation sources and state targets generally do not increase beyond 2025.

It is important to note, however, that the aggregate targets and qualifying generation shown in Figure LR3-1 may mask significant regional variation, as well as technology- or tier-specific shortfalls. While some regions may produce excess qualifying generation, others may produce just enough to meet the requirement or may need to import generation from adjoining regions to meet state targets. Furthermore, even though there is more qualifying generation in aggregate than is needed to meet the targets, states with technology-specific goals could still have deficits for certain technologies. Also, this projected pattern of aggregate surplus does not necessarily imply that projected generation would be the same without state RPS policies. State RPS policies may encourage investment in places where it otherwise would not occur or would not occur in the amounts projected, even as other parts of the country see substantial growth above state targets or in their absence. It does, however, suggest that state RPS programs will not be the sole reason for future growth in renewable generation, and that the importance of RPS targets in contributing to growth in renewable generation will decline over time.

Currently, 29 states and the District of Columbia have enforceable RPS or similar laws (Table LR3-1) [20]. Under such standards, each state determines its own levels of renewable generation, eligible technologies [21], and noncompliance penalties. No new RPS programs have been enacted since 2009. There have been a number of modifications to existing programs in recent years, however, building on state implementation experience and changing market conditions.

The year 2013 saw a large number of proposed legislative modifications to existing RPS programs [22], including some attempts to weaken the targets of existing programs significantly. However, only a small subset was enacted, and no states passed major rollbacks or repeals of RPS programs. The changes that were enacted affect some aspects of the laws and implementing regulations, but in general they do not have substantive effects on the representation of state RPS programs in the AEO2014 Reference case. Key changes include:

### Colorado

Senate Bill 13-252 [23], signed into law in June 2013, doubles the renewable energy target for large electric cooperatives and cooperative associations to 20% of total electric sales by 2020. The law also adds a renewable distributed generation requirement for electric cooperatives, removes preferential credit multipliers for in-state eligible sources, and expands the set of qualifying energy sources to include coal-mine methane and pyrolysis gas from municipal solid waste.

### Connecticut

Senate Bill 1138 [24], enacted in June 2013, relaxes restrictions on how hydroelectric generation can be applied to Connecticut's RPS. The statute expands the set of qualifying Class I resources to include run-of-river hydropower up to 30 MW—an increase over the previous cap of 5 MW—as well as additional sources, such as geothermal electric and some types of biogas. In addition, large-scale hydropower (greater than 30 MW) could, under specified circumstances, be allowed to meet an increasing portion of the RPS, starting at 1% of sales in 2016 and rising to 5% of sales by 2020.

### Maryland

The Maryland Offshore Wind Energy Act of 2013, House Bill 226 [25], was enacted in April 2013. The legislation adds to Maryland's existing RPS an offshore wind technology-specific requirement of up to 2.5% of total sales starting in 2017. Qualifying offshore facilities must be located in specific areas of the Outer Continental Shelf and are subject to a defined process for approval by the Maryland Public Service Commission. Projects will be subject to several cost containment triggers: the impact on residential customers cannot exceed $1.50 per month, and renewable energy credits for offshore wind should not exceed $190 per MWh.

### Minnesota

In May 2013 Minnesota enacted House Floor 729 [26], which mandates that investor-owned utilities meet a solar technology-specific standard of 1.5% of sales by 2020. This minimum is in addition to Minnesota's previously existing target, effectively raising the total percentage of required renewable generation for investor-owned utilities by 1.5%. Of the new solar mandate, 10% must be achieved via small systems that are 20 kilowatts or less. The bill also directs investor-owned utilities to design a "value of solar" tariff that could be used in lieu of a traditional retail rate-compensated net metering agreement.

### Montana

Montana enacted several bills during 2013 related to the state's RPS [27]. Major changes include expanding the set of RPS-qualifying technologies to include generation from additional sources, such as: incremental capacity additions at existing hydropower projects; storage technologies such as flywheels, batteries, and hydroelectric pumped storage; and certain types of chemically treated biomass burned at small plants. Small utilities serving 50 or fewer customers are now exempt from the obligation to meet the state's RPS.

Table LR3-1. Renewable portfolio standards in the 29 states and District of Columbia with current mandates

| State | Target | Qualifying renewables | Qualifying other (thermal, efficiency, nonrenewable distributed generation, etc.) | Compliance mechanisms |
|---|---|---|---|---|
| AZ | 15% by 2025 | Solar, wind, biomass, hydro, landfill gas (LFG), anaerobic digestion built after January 1, 1997, geothermal | Direct use of solar heat, ground-source heat pumps, renewable-fueled combined heat and power (CHP), fuel cells | Credit trading is allowed, with some bundling restrictions. Includes distributed generation requirement, starting at 5% of target in 2007, growing to 30% by 2012 and beyond. |
| CA | 33% by 2020 | Solar, wind, biomass, geothermal, LFG and municipal solid waste (MSW), small hydro, biodiesel, anaerobic digestion, marine | Energy storage, fuel cells | Credit trading is allowed, with some restrictions. Renewable energy credit prices are capped at $50 per MWh. |
| CO | 30% by 2020 for investor-owned utilities; 20% by 2020 for large electric cooperatives; 10% by 2020 for other cooperatives and municipal utilities serving more than 40,000 customers | Solar, wind, hydro, biomass, geothermal electric, anaerobic digestion, LFG | Recycled energy, coal-mine methane, pyrolysis gas produced from MSW, fuel cells | Credit trading is allowed. Renewable distributed generation requirement applies to investor-owned utilities (3% of sales by 2020) and electric cooperatives (0.75% or 1% of sales by 2020, depending on size). Generation associated with certain projects that have specific ownership or transmission ties with small utilities, entities, or individuals is eligible to earn credit multipliers. |
| CT | 27% by 2020 (23% renewables, 4% efficiency and CHP) | Solar, wind, biomass, hydro (with exceptions), geothermal, LFG/MSW, anaerobic digestion and other biogas, marine | CHP, fuel cells | Credit trading is allowed. Obligated providers may comply via an alternative compliance payment of $55 per MWh. The target is made up of three class tiers, with tier-specific targets. |
| DE | 25% by 2026 | Solar, wind, biomass, hydro, geothermal, LFG, anaerobic digestion, marine | Fuel cells | Credit trading is allowed. Credit multipliers are awarded for several compliance specifications, including a 300% credit awarded for generation from in-state distributed solar and renewable-fueled fuel cells. Target increases for some suppliers can be subject to a cost threshold. |
| DC | 20% by 2020 | Solar, wind, biomass, hydro, geothermal, LFG/MSW, marine | Direct use of solar, cofiring, fuel cells | Credit trading allowed. The target includes a solar-specific set-aside, equivalent to 2.5% of sales by 2023. Obligated providers may also comply via a tier-specific alternative compliance payment. |
| HI | 40% by 2030 | Solar, wind, biomass, hydro, geothermal, LFG/MSW, anaerobic digestion, marine, certain biofuels | Direct use of solar, ground-source heat pumps, ice storage, CHP, efficiency programs, hydrogen, fuel cells | Credits cannot be traded. Eligibility of several of the "qualifying other" displacement technologies is restricted after 2015. Utility companies can calculate compliance over all utility affiliates. |
| IL | 25% by 2026 | Solar, wind, biomass, hydro, anaerobic digestion, biodiesel, LFG | None | Credit trading is allowed. Target includes specific requirements for wind, solar, and distributed generation. The procurement process is subject to a cost cap. |
| IA | 105 MW of eligible renewable resources | Solar, wind, some types of biomass and waste, small hydro, anaerobic digestion, LFG | None | Iowa's investor-owned utilities are currently in full compliance with this standard, achieved primarily through wind capacity. |

*(continued on next page)*

Table LR3-1. Renewable portfolio standards in the 29 states and District of Columbia with current mandates (cont.)

| State | Target | Qualifying renewables | Qualifying other (thermal, efficiency, nonrenewable distributed generation, etc.) | Compliance mechanisms |
|---|---|---|---|---|
| KS | 20% of each peak demand capacity by 2020 | Solar, wind, hydro, biomass, LFG | Direct use of solar heat, fuel cells | Credit trading is allowed. Eligible in-state capacity counts for 1.1 times its actual capacity. |
| ME | 40% total by 2017, 10% by 2017 from new resources entering service in 2005 and beyond | Solar, wind, biomass, hydro, geothermal, LFG/MSW, marine, hydro | CHP, fuel cells | Credit trading is allowed. The Maine Public Utilities Commission sets an annually adjusted alternative compliance payment. Community-based generation projects are eligible to earn credit multipliers. |
| MD | 20% by 2022 | Solar, wind, biomass, geothermal, LFG/MSW, anaerobic digestion, marine, hydro | Solar water heating, ground-source heat pumps, fuel cells | Credit trading is allowed. The target includes minimum levels of compliance from solar and offshore wind. Utilities may pay an alternative compliance payment in lieu of procuring eligible sources, with a tier-specific compliance schedule. |
| MA | 22.1% by 2020 (and an additional 1% per year thereafter) | Solar, wind, hydro, some biomass technologies, LFG/MSW, geothermal electric, anaerobic digestion, marine | Fuel cells | Credit trading is allowed. The target for new resources includes a solar-specific goal to achieve 400 MW of in-state solar capacity, which is translated into an annual target for obligated providers. Obligated providers may comply via an alternative compliance payment (ACP), which varies in level by the requirement class. The ACP is designed to be higher than the cost of other compliance options. |
| MI | 10% by 2015, with specific new capacity goals for utilities that serve more than 1 million customers | Solar, wind, hydro, biomass, LFG/MSW, geothermal electric, anaerobic digestion, marine | CHP, coal with carbon capture and sequestration, energy efficiency measures for up to 10% of a utility's sales obligation | Credit trading is allowed. Solar power receives a credit multiplier; other generation and equipment features—such as peak generation, storage, and use of equipment manufactured in-state—can earn bonus credits. |
| MN | 31.5% by 2020 (Xcel), 26.5% by 2025 (other investor-owned utilities), or 25% by 2025 (other utilities) | Solar, wind, hydro, biomass, LFG/MSW, anaerobic digestion | Cofiring, hydrogen | Credit trading is allowed. Target includes 1.5% solar standard for investor-owned utilities; Xcel's target also includes 25% of sales specifically from wind and solar (with a 1% maximum for solar). State regulators can penalize noncompliance at the estimated cost of compliance. |
| MO | 15% by 2021, 0.3% of retail electricity sales from solar electricity by 2021 | Solar, wind, hydro, biomass, LFG/MSW, anaerobic digestion, ethanol | Fuel cells | Credit trading is allowed. Noncompliance payments are set at double the market rate for renewables. |
| MT | 15% by 2015 | Solar, wind, hydro, geothermal, biomass, LFG, anaerobic digestion | Energy storage using renewable energy, fuel cells | Credit trading is allowed, with a price cap of $10 per MWh. There are specific targets for community-based projects. |
| NV | 25% by 2025 | Solar, wind, hydro, geothermal, biomass, LFG/MSW, biodiesel, anaerobic digestion | Waste tires, direct use of solar and geothermal heat, efficiency measures (which can account for one-quarter of the target in any given year) | Credit trading is allowed. Solar PV receives a credit premium, with an additional premium for customer-sited systems. |
| NH | 24.8% by 2025 | Solar, wind, small hydro, marine, LFG, biomass, anaerobic digestion, certain biodiesel fuels | Fuel cells, CHP, microturbines, direct use of solar heat, ground-source heat pumps, hydrogen | Credit trading is allowed, and utilities may pay into a fund in lieu of holding credits. The target has four separate compliance classes, by technology type. |

(continued on next page)

Table LR3-1. Renewable portfolio standards in the 29 states and District of Columbia with current mandates (cont.)

| State | Target | Qualifying renewables | Qualifying other (thermal, efficiency, nonrenewable distributed generation, etc.) | Compliance mechanisms |
|---|---|---|---|---|
| NJ | 20.38% by 2021 with an additional 4.1% solar by 2027 | Solar, wind, hydro, geothermal, LFG/MSW, marine, anaerobic digestion | Fuel cells | Credit trading is allowed, with an alternative compliance payment set by state regulators. Solar and offshore wind are subject to separate requirements and have separate enforcement provisions. |
| NM | 20% by 2020 for investor-owned utilities, 10% by 2020 for cooperatives | Solar, wind, hydro, geothermal, LFG, biomass, anaerobic digestion | Zero-emission technology (not including nuclear), fuel cells | Credit trading is allowed. The program cannot increase consumer costs beyond a threshold amount, increasing to 3% of annual costs by 2015. Technology minimums are established for wind, solar, and certain other resources. |
| NY | 29% by 2015 | Solar, wind, hydro, biomass, LFG, anaerobic digestion, certain biofuels, marine | Direct use of solar heat, CHP, fuel cells | Credit trading is not allowed. Compliance is achieved through purchases by state authorities, funded by a surcharge on investor-owned utilities. Government-owned utilities may have their own, similar programs. |
| NC | 12.5% by 2021 for investor-owned utilities, 10% by 2018 for municipal and cooperative utilities | Solar, wind, small hydro, biomass, geothermal, LFG, marine, anaerobic digestion | Direct use of solar heat, CHP, hydrogen, demand reduction | Credit trading is allowed. Impacts on customer costs are capped at specified levels. There are specific targets for solar and certain animal waste projects. |
| OH | 12.5% by 2024 | Solar, wind, hydro, biomass, geothermal, LFG/MSW, anaerobic digestion | Energy storage, fuel cells, and a separate 12.5% target for "advanced energy technologies," including coal mine methane, advanced nuclear, efficiency, clean coal | Credit trading is allowed. Alternative compliance payments are set by law and adjusted annually. There is a separate target for solar electricity generation. |
| OR | 5% by 2025 for utilities with less than 1.5% of total sales; 10% by 2025 for utilities with at least 1.5% but less than 3% of total sales; 25% by 2025 for all others | Solar, wind, hydro, biomass, geothermal, LFG/MSW, anaerobic digestion, marine | Hydrogen | Credit trading is allowed, with an alternative compliance payment and a limit on expenditures of 4% of annual revenue. Solar receives a credit multiplier. |
| PA | 18% by 2020 | Solar, wind, hydro, biomass, geothermal, LFG/MSW, anaerobic digestion | CHP, certain advanced coal technologies, certain energy efficiency technologies, fuel cells, direct use of solar heat, ground-source heat pumps, other distributed generation technologies | Credit trading is allowed, with an alternative compliance payment. Separate targets are set for solar and two different combinations of renewable, fossil, and efficiency technologies. |
| RI | 16% by 2019 | Solar, wind, hydro, biomass, geothermal, anaerobic digestion, LFG, biodiesel, marine | Fuel cells | Credit trading is allowed, with an alternative compliance payment. There is a separate target for 90 MW of new renewable capacity. |
| TX | Enforceable target of 5,880 MW by 2015 | Solar, wind, hydro, biomass, geothermal, LFG, marine | Direct use of solar heat, ground-source heat pumps | Credit trading is allowed, with capacity targets converted to generation equivalents. State regulators may cap credit prices. 500 MW must be from resources other than wind. |

*(continued on next page)*

Table LR3-1. Renewable portfolio standards in the 29 states and District of Columbia with current mandates (cont.)

| State | Target | Qualifying renewables | Qualifying other (thermal, efficiency, nonrenewable distributed generation, etc.) | Compliance mechanisms |
|---|---|---|---|---|
| WA | 15% by 2020 | Solar, wind, hydro, biomass, geothermal, LFG, anaerobic digestion, biodiesel, marine | CHP | Credit trading is allowed, with an administrative penalty for noncompliance. |
| WI | 10% by 2015 | Solar, wind, hydro, biomass, geothermal, LFG/MSW, small hydro, anaerobic digestion, marine, biogas | CHP, pyrolysis, synthetic gas, direct use of solar or biomass heat, ground-source heat pumps, fuel cells | Credit trading is allowed. |

### Nevada

In June 2013 Nevada enacted Senate Bill 252 [28], which places new limits on the extent to which energy efficiency measures count toward the state's existing standard. The bill also restricts multiplier credits for customer-sited solar generation to installations placed in service before the end of 2015. The obligated utility, Nevada Energy, is also now required by Senate Bill 123 [29] to meet a capacity standard of 350 MW of new renewable capacity by the end of 2021. However, the same capacity can also be applied to the existing sales-based standard and thus does not necessarily require additional capacity beyond that which may have been required to meet the existing standard.

### Washington

Washington enacted two bills—Senate Bills 5400 [30] and 5297 [31]—that increase compliance flexibility options for certain providers. Under Senate Bill 5400, utilities that serve customers in multiple states are now allowed to meet their obligations with sources from those states. Senate Bill 5297 allows for the use of "coal transition power" for compliance under very specific circumstances for utilities not experiencing load growth.

## LR4. U.S. response to the nuclear accident at Fukushima Daiichi

Since the March 2011 accident at Japan's Fukushima Daiichi nuclear power plant, the U.S. Nuclear Regulatory Commission (NRC) and the U.S. nuclear industry have been working to address issues related to the accident. The NRC and the U.S. nuclear industry initiated an immediate coordinated response to the accident, as well as long-term actions intended to assure the safety of operating and planned reactors in the United States. The ultimate cost of complying with NRC orders and proposed regulations and industry-led initiatives remains uncertain, as do the potential impacts on nuclear power plant operations. Although they are not specifically modeled in AEO2014, NRC actions and industry initiatives are being monitored by EIA so that potential costs and operational impacts can be included in future AEOs.

The NRC conducted a systematic and methodical review of its own processes and regulations in light of the accident at Fukushima. On July 12, 2011, the NRC's Near-Term Task Force released its report, *Recommendations for Enhancing Reactor Safety in the 21st Century* [32]. The report contains 12 recommendations, including both short- and long-term actions for consideration, and prioritizes the implementation of the recommendations.

In order to address the short-term recommendations, the NRC issued three orders in March 2012 that require nuclear power plants to implement measures related to lessons learned from the Fukushima accident, as follows:

- All boiling-water reactors (BWRs) with Mark I and II containment systems must have reliable hardened containment venting capability to reduce pressure and hydrogen buildup. This may require improving or replacing existing containment ventilation systems [33].
- Reactors must have enhanced instrumentation installed to monitor water levels in their spent fuel pools in the event of an emergency [34].
- Nuclear power plants must be capable of responding to multiple simultaneous events and ensuring that reactors and spent fuel pools remain cooled. The order specifies a three-phase approach involving use of installed on-site resources, use of portable on-site equipment, and indefinite use of off-site resources [35].

The NRC stated that, in all cases, the existing fleet of reactors can continue operating safely while implementing the orders. The orders were effective immediately and included timetables for responses and actions.

In the three orders listed above, the NRC required an integrated plan to be submitted by February 2013, with initial status reports due in 60 days. The NRC specified that operating reactors must complete modifications within two refueling cycles after submitting an integrated plan, or by the end of 2016, whichever comes first. Any reactor with a construction permit issued under 10 CFR Part 50 (e.g., Watts Bar Unit 2) was required to comply with the above orders prior to receiving an operating license. Any reactor issued a Combined Operating License (COL) under 10 CFR Part 52 (i.e., Vogtle Units 3 and 4 and Summer Units 2 and 3) was required to implement all requirements in the orders before the initial fuel loading. Compliance assessments are underway at nuclear power plants. The requirements of the orders remain in place until superseded by other orders or rulemaking. As discussed below, NRC is considering or has initiated rulemaking on several topics, and some of the dates established in the original orders have been modified.

In November 2012, as an addition to the original order issued to address more robust containment venting systems, the NRC began considering whether to propose a rule that would require containment venting systems to filter all releases during an accident for boiling water reactors with Mark I and Mark II containments [*36*]. If the NRC decides to pursue such a rulemaking, a final rule could be issued in 2017 [*37*].

Utilities continue to provide documentation to the NRC on equipment procured to respond to a prolonged loss of power at a reactor (station blackout) as well as spent fuel pool water level monitoring instrumentation. In March 2013, the NRC decided to proceed with a rulemaking to address station blackout mitigation [*38*]. In its July 2013 regulatory basis document [*39*], the NRC noted: "One dual-unit site estimated that the order may cost approximately $25 million, while a second dual-unit site estimated the cost at $43 million." The final rule is scheduled for issuance by December 2016.

By June 2013, two detailed inspections (or "walkdowns") had been completed at each reactor to evaluate potential seismic and flooding hazards. The NRC is in the process of auditing the results of the walkdowns. All flooding re-evaluations are due to the NRC by March 2015 [*40*]. The NRC will review the analyses and issue a safety assessment for each site. For nuclear power plants requiring a seismic risk analysis, the NRC performed a prioritization of plants in the Central and Eastern United States (CEUS) and the Western United States (WUS). Plants in more seismically active WUS and CEUS locations will complete risk evaluations by June 2017, and those in less active CEUS locations will complete risk evaluations by December 2019 [*41*].

In November 2013, the NRC announced proposed rulemaking language to ". . . strengthen and integrate onsite emergency response capabilities." [*42*] The final rule, which is likely to be issued in March 2016, is expected to address accident mitigation strategies; integration of accident mitigation procedures; identification of command and control roles during an accident; conduct of drills and exercises; training; and include severe accident situations in examinations for reactor operators. In its comments [*43*] on the NRC's draft regulatory basis [*44*], the Nuclear Energy Institute (NEI) estimated a cost of $17 million for the nuclear fleet—or $275,000 per unit—to develop and implement new training plans. NEI also estimated increased training costs of $250,000 per site per year and annual severe accident drill costs of $250,000 per site.

In addition to the NRC actions described above, the Electric Power Research Institute (EPRI), the Institute of Nuclear Power Operations (INPO), and NEI formed a Fukushima Response Steering Committee to integrate and coordinate the industry's response to the accident. In February 2012, the Steering Committee jointly released a report, *The Way Forward: U.S. Industry Leadership in Response to Events at the Fukushima Daiichi Nuclear Power Plant*, which discusses activities to oversee and coordinate responses to emergencies [*45*]. INPO prepared a detailed report on post-accident events at Fukushima Daiichi [*46*], and on November 11, 2011, the detailed report was provided to the U.S. Congress, the NRC, and the U.S. nuclear industry. The nuclear industry, through NEI, developed its FLEX strategy—a comprehensive, flexible, and integrated plan to mitigate the effects of severe natural phenomena and to take steps to achieve safety benefits quickly [*47*]. The FLEX approach, implemented in 2012, was informed by the industry's response to the September 11, 2001, terrorist attacks in the United States. Two regional response centers will be located near Memphis, Tennessee, and Phoenix, Arizona. From those regional response centers, critical emergency equipment can be delivered to nuclear power plants within 24 hours. The regional response centers are planned to be fully operational by August 2014 [*48*].

In addition to activities that focus on reactors and the utilities that operate them, the NRC has spent more than two years evaluating how best to respond to the first of the 12 recommendations made in the July 2011 *Near-Term Task Force Review of Insights from the Fukushima Dai-Ichi Accident* [*49*], which recommended establishment of a "logical, systematic, and coherent regulatory framework for adequate protection that appropriately balances defense-in-depth and risk considerations." Defense-in-depth is a layered approach to safety that involves the use of multiple redundant and independent safety systems. NRC's evaluation of this recommendation [*50*] was discussed publicly in January 2014 and included proposed actions on a policy statement that would detail, among other things, the decision criteria for ensuring adequate defense-in-depth. The proposed actions also identify the need to clarify the role of voluntary industry initiatives in the NRC regulatory process.

The ultimate cost to the nuclear industry of addressing Fukushima-related issues remains uncertain, as do the potential impacts on nuclear power plant operations. In a meeting with the NRC in April 2013, Dominion Energy estimated that the cost of post-Fukushima actions could be $30 to $40 million per unit and $180 to $240 million for its fleet of six units [*51, 52*]. AEO2014 does not include potential post-Fukushima effects on nuclear capacity and generation, but costs and operational impacts will be monitored for inclusion in future AEOs as NRC actions and industry initiatives progress.

# Endnotes for legislation and regulations

**Links current as of January 2014**

1. A complete list of the laws and regulations included in AEO2014 is provided in *Assumptions to the Annual Energy Outlook 2014*, Appendix A, http://www.eia.gov/forecasts/aeo/assumptions/pdf/0554(2014).pdf.
2. Regional Greenhouse Gas Initiative, "2012 Program Review" (New York, NY: February 7, 2013), http://www.rggi.org/design/program-review.
3. U.S. Government Printing Office, "Energy Policy Act of 2005, Public Law 109-58" (Washington, DC: August 8, 2005), http://www.gpo.gov/fdsys/pkg/PLAW-109publ58/pdf/PLAW-109publ58.pdf.
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5. Colorado State University, Center for the New Energy Economy, "State Renewable Portfolio Standards Hold Steady or Expand in 2013 Session" (Fort Collins, CO: 2013), http://www.pelinkage.com/graphics/uploads/2013-State-By-State-RPS-Analysis.pdf.
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8. U.S. Environmental Protection Agency, "Mercury and Air Toxics Standards (MATS)" (Washington, DC: last updated March 27, 2012), http://www.epa.gov/mats.
9. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2013*, DOE/EIA-0554(2013) (Washington, DC: May 2013), http://www.eia.gov/forecasts/aeo/assumptions. Table 8.8 indicates how much of a plant's uncontrolled mercury emissions are removed by a specific configuration of environmental control equipment for a given coal type. The strategies used by coal plants to comply with the mercury, acid gases, and toxic metals are discussed in the documentation.
10. *White Stallion Energy Center, LLC, et al. v. United States Environmental Protection Agency*, USCA Case #12-1100 (January 22, 2013), http://www.delawaneir.org/Documents/AdminRec/MATS.pdf.
11. U.S. Environmental Protection Agency, "Clean Air Interstate Rule (CAIR)" (Washington, DC: December 19, 2012), http://www.epa.gov/cair/index.html#older.
12. Further details on the modeling strategies for MATS and CAIR can be found in the forthcoming report, *Assumptions to the Annual Energy Outlook 2014*, and the forthcoming *Electricity Market Module of the National Energy Modeling System Model Documentation 2014*.
13. United States Court of Appeals for the District of Columbia Circuit, *EME Homer City Generation, L.P., v. Environmental Protection Agency, et al.*, No. 11-1302 (decided August 21, 2012), http://www.cadc.uscourts.gov/internet/opinions.nsf/19346B280C78405C85257A6D004DC0B5/$file/11-1302-1390314.pdf.
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15. U.S. Government Printing Office, "Energy Policy Act of 2005, Public Law 109-58" (Washington, DC: August 8, 2005), http://www.gpo.gov/fdsys/pkg/PLAW-109publ58/pdf/PLAW-109publ58.pdf.
16. U.S. Government Printing Office, "Energy Independence and Security Act of 2007, Public Law 110-140" (Washington, DC: December 19, 2007), http://www.gpo.gov/fdsys/pkg/PLAW-110publ140/pdf/PLAW-110publ140.pdf.
17. Does not include the RPS policy for Hawaii, because NEMS provides electricity market projections only for the contiguous lower 48 states.
18. More information about the Database of State Incentives for Renewables & Efficiency (DSIRE) can be found at http://www.dsireusa.org.
19. G. Barbose, "Renewable Portfolio Standards in the United States: A Status Update" (November 2013), http://emp.lbl.gov/sites/all/files/rps_survey_nov_2013.pdf.
20. Enumerations of state RPS policies may vary from source to source, as these policies vary significantly from state to state with no universal definition. Previous enumerations of 30 state RPS policies by EIA have included a policy in West Virginia that allows for several types of fossil generators to be built instead of renewable generators to meet the portfolio requirement. However, because EIA does not model this in the *Annual Energy Outlook* as an RPS, it is not included in the current enumeration.
21. Eligible technologies, and even the definitions of technologies or fuel categories, vary by state. For example, one state's definition of renewables may include hydropower while another's may not. Table LR-1 provides more detail on how the technology or fuel category is defined by each state.

22. Colorado State University, "State Renewable Portfolio Standards Hold Steady or Expand in 2013 Session," *Center for the New Energy Economy* (Fort Collins, CO: July 2013), http://www.dsireusa.org/graphics/uploads/2013-State-by-State-RPS-Analysis.pdf.
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24. State of Connecticut General Assembly, "Senate Bill 1138" (June 5, 2013), http://www.cga.ct.gov/2013/ACT/PA/2013PA-00303-R00SB-01138-PA.htm.
25. State of Maryland General Assembly, "House Bill 226: Maryland Offshore Wind Energy Act of 2013" (April 2013), http://mgaleg.maryland.gov/2013RS/bills/hb/hb0226e.pdf.
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29. State of Nevada Legislature, "Senate Bill 123" (June 2013), http://www.leg.state.nv.us/Session/77th2013/Bills/SB/SB123_EN.pdf.
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32. U.S. Nuclear Regulatory Commission, *Recommendations for Enhancing Reactor Safety in the 21st Century* (Washington, DC: July 12, 2011), http://pbadupws.nrc.gov/docs/ML1118/ML111861807.pdf.
33. U.S. Nuclear Regulatory Commission, *Issuance of Order to Modify Licenses with Regard to Reliable Hardened Containment Vents* (Washington, DC: March 12, 2012), http://www.nerc-net.org/usd/fukushima/documents/NRC%20March20%20Order%20HardenedContainmentVents.pdf.
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35. U.S. Nuclear Regulatory Commission, *Issuance of Order to Modify Licenses with Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events* (Washington, DC: March 12, 2012), http://pbadupws.nrc.gov/docs/ML1205/ML12054A735.pdf.
36. U.S. Nuclear Regulatory Commission, *Policy Issue Notation Vote: Consideration of Additional Requirements for Containment Venting Systems for Boiling Water Reactors with Mark I and Mark II Containments* (Washington, DC: November 26, 2012), http://www.nrc.gov/reading-rm/doc-collections/commission/secys/2012/2012-0157secy.pdf.
37. *Ibid.*
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51. *Nuclear Engineering International*, "Half way — a review of post Fukushima actions in the Americas" (July 24, 2013), http://www.neimagazine.com/features/featurehalf-way---a-review-of-post-fukushima-actions-in-the-americas/.

52. D.A. Heacock, Dominion Nuclear, "Fukushima Dai-ichi Dominion Experience Overview" (Washington, DC: April 23, 2013), http://www.nrc.gov/reading-rm/doc-collections/commission/slides/2013/20130423/heacock-slides-20130423.pdf.

## Figure and table sources

**Links current as of January 2014**

**Figure LR3-1. Total qualifying renewable generation required for combined state renewable portfolio standards and projected total achieved, 2013-40:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

**Table LR3-1. Renewable portfolio standards in the 29 States and District of Columbia with current mandates:** U.S. Energy Information Administration, Office of Energy Analysis. Based on a review of enabling legislation and regulatory actions from the various States of policies identified by the Database of State Incentives for Renewables & Efficiency (as of January 15, 2014), website www.dsireusa.org.

# Issues in focus

## Introduction

The "Issues in focus" section of the *Annual Energy Outlook* (AEO) provides in-depth discussions on topics of special significance, including changes in assumptions and recent developments in technologies for energy production and consumption. Selected topics from recent AEOs are listed in Table IF-1.

Selected quantitative results from the issues discussed in AEO2014 are available in Appendix D. The first topic updates a discussion included in a number of previous AEOs, comparing the Reference case projections with two cases based on different assumptions about the future course of existing energy policies: one assumes the elimination of sunset provisions for various energy tax credits that are scheduled to expire under current law; the other assumes—in addition to the elimination of sunset provisions on various tax credits—the extension or expansion of three existing policies: corporate average fuel economy (CAFE) standards, appliance standards, and building code improvements.

Other topics discussed in this section include:

- U.S. tight oil production trends and supply projections based on alternative assumptions and a methodology using well-level data aggregated to the county level
- Potential of liquefied natural gas as a freight locomotive fuel
- Impacts of demographic issues and travel behavior on light-duty vehicle (LDV) energy demand
- Impacts of lower natural gas prices on industrial production
- Implications of accelerated power plant retirements
- Variations in renewable electricity projections in AEO2014 cases
- Implications of lower growth in electricity demand.

Table IF-1. Key analyses from "Issues in focus" in recent AEOs

| AEO2013 | AEO2012 | AEO2011 |
|---|---|---|
| U.S. reliance on imported liquid fuels in alternative scenarios | Potential efficiency improvements and their impacts on end-use energy demand | Increasing light-duty vehicle greenhouse gas and fuel economy standards for model years 2017 to 2025 |
| Competition between coal and natural gas in the electric power sector | Energy impacts of proposed CAFE standards for light-duty vehicles, model years 2017 to 2025 | Fuel consumption and greenhouse gas emissions standards for heavy-duty vehicles |
| Nuclear power in AEO2013 | Impacts of a breakthrough in battery vehicle technology | Potential efficiency improvements in alternative cases for appliance standards and building codes |
| Effect of natural gas liquids growth | Heavy-duty natural gas vehicles | Potential of offshore crude oil and natural gas resources |
| | Changing structure of the refining industry | Prospects for shale gas |
| | Changing environment for fuel use in electricity generation | Cost uncertainties for new electric power plants |
| | Nuclear power in AEO2012 | Carbon capture and storage: Economics and issues |
| | | Power sector environmental regulations on the horizon |

**Sources:** U.S. Energy Information Administration, *Annual Energy Outlook 2013*, DOE/EIA-0383(2013) (Washington, DC: April 2013); U.S. Energy Information Administration, *Annual Energy Outlook 2012*, DOE/EIA-0383(2012) (Washington, DC: June 2012); and U.S. Energy Information Administration, *Annual Energy Outlook 2011*, DOE/EIA-0383(2011) (Washington, DC: April 2011).

## IF1. No Sunset and Extended Policies cases

Two alternative cases are discussed in this section to provide insight into the sensitivity of the Reference case to scenarios, in which existing tax credits that have sunset dates are assumed not to sunset (No Sunset case), or other policies (i.e., CAFE standards, appliance standards, and building codes) are expanded beyond current provisions in combination with the elimination of the sunset dates on existing tax credits (Extended Policies case). No attempt is made to cover the full range of possible uncertainties in these areas, and readers should not view the cases discussed as EIA projections of how laws or regulations are likely to, or should, be changed. The cases examined here look only at federal laws or regulations and do not examine state laws or regulations.

The No Sunset and Extended Polices cases generally lead to lower estimates for overall delivered energy consumption, increased use of renewable fuels (particularly for electricity generation), reduced energy-related carbon dioxide ($CO_2$) emissions, lower energy prices, and lower government tax revenues.

### Background

The AEO2014 Reference case is best described as a current laws and regulations case, because it generally assumes that existing laws and regulations remain unchanged throughout the projection period unless the legislation establishing the regulations sets a sunset date or specifies how they will change. The Reference case often serves as a starting point for analysis of proposed changes in legislation or regulations. While this definition of the Reference case supports a variety of further analysis, there may be interest in alternative cases that reflect updates or extensions of current laws and regulations that the AEO2014 Reference case excludes. Areas of particular interest include:

- Laws or regulations that have a history of being extended beyond their legislated sunset dates. Examples include the various tax credits for renewable fuels and technologies, which have been extended with or without modifications several times since their initial implementation.
- Laws or regulations that call for periodic updating of initial specifications. Examples include appliance efficiency standards issued by the U.S. Department of Energy (DOE) and Corporate Average Fuel Economy (CAFE) and greenhouse gas (GHG) emissions standards for vehicles issued by the National Highway Traffic Safety Administration (NHTSA) and the U.S. Environmental Protection Agency (EPA).
- Laws or regulations that allow or require the appropriate regulatory agency to issue new or revised regulations under certain conditions. Examples include the numerous provisions of the Clean Air Act that require EPA to issue or revise regulations if it finds that an environmental quality target is not being met.

### Analysis cases

The two cases prepared—the No Sunset case and the Extended Policies case—incorporate all the assumptions from the AEO2014 Reference case, except as identified below.

#### No Sunset case

The sunset provisions for tax credits are eliminated for renewable energy sources in the utility, industrial, and buildings sectors and for energy-efficient equipment in the buildings sector, including the following:

- The production tax credit (PTC) of 1.1 or 2.3 cents/kilowatthour (kWh), depending on the technology, and the 30% investment tax credit (ITC) available for wind, geothermal, biomass, hydroelectric, and landfill gas resources are extended indefinitely as opposed to expiring at the end of 2013.
- For solar power investments, a 30% ITC that is scheduled to revert to a 10% credit in 2016 is assumed to be extended indefinitely at 30%.
- In the buildings sector, personal tax credits for the purchase of energy-efficient and renewable equipment, including photovoltaics (PV), are assumed to be extended indefinitely, as opposed to ending in 2013 or in 2016, respectively, as prescribed by current law. The business ITCs for commercial-sector generation technologies and geothermal heat pumps are assumed to be extended indefinitely, as opposed to expiring in 2016. The business ITC for solar systems is assumed to remain at 30% instead of reverting to 10%.
- In the industrial sector, the 10% ITC for combined heat and power (CHP), which is assumed to end in 2016 in the AEO2014 Reference case [1], is assumed in the No Sunset case to be preserved through 2040.
- The $1.01/gallon (nominal) subsidy for cellulosic ethanol and $1.00/gallon (nominal) biodiesel subsidy are assumed to be extended at those levels from their recent expiration at the end of 2013 through the end of the projection period [2].

#### Extended Policies case

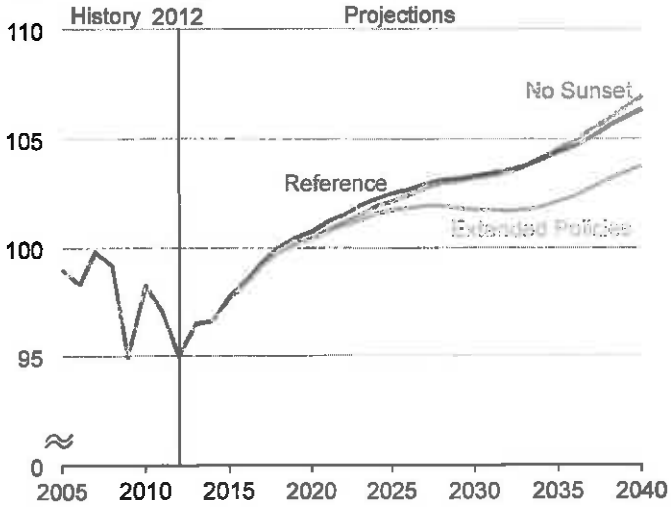
The Extended Policies case includes additional updates to federal equipment efficiency standards that were not considered in the Reference case or the No Sunset case. Residential and commercial end-use technologies eligible for incentives in the No Sunset case are not subject to new standards. Other than those exceptions, the Extended Policies case adopts the same assumptions as the No Sunset case, in addition to the following:

- Federal equipment efficiency standards are assumed to be updated at periodic intervals, consistent with the provisions in existing law, at levels based on ENERGY STAR specifications or on the Federal Energy Management Program purchasing guidelines for federal agencies, as applicable. Standards also are introduced for products that are not currently subject to federal efficiency standards.
- Federal energy codes for residential and commercial buildings are assumed to be updated periodically, providing additional improvement to new construction. The equipment standards and building codes assumed for the Extended Policies case are meant to illustrate the potential effects of those policies on energy consumption for buildings. No cost-benefit analysis or evaluation of impacts on consumer welfare was completed in developing the assumptions. Likewise, no technical feasibility analysis was conducted, although standards were not allowed to exceed the "maximum technologically feasible" levels described in DOE's technical support documents.
- The AEO2014 Reference, No Sunset, and Extended Policies cases include the joint attribute-based CAFE and vehicle GHG emissions standards for model year (MY) 2012 to MY 2025 for light-duty vehicles (LDVs). The Reference and No Sunset cases assume that the CAFE standards are then held constant at MY 2025 levels in subsequent model years, although the fuel economy of new LDVs continues to rise modestly over time. The Extended Policies case modifies the assumption in the Reference and No Sunset cases, assuming continued increases in CAFE standards at an annual average rate of 1.3% for new LDVs after MY 2025.
- The AEO2014 Reference, No Sunset, and Extended Policies cases include the heavy-duty vehicle (HDV) fuel consumption and GHG emissions standards for MY 2014 to MY 2018. The Reference and No Sunset cases assume that the standards are held constant at MY 2018 levels in subsequent model years, although the fuel economy of HDVs rises modestly thereafter. The Extended Policies case includes an increase in fuel consumption and GHG emissions standards for 13 vehicle size classes.
- In the industrial sector, the ITC for CHP is extended to cover all properties with CHP, no matter what the system size (which may include multiple units), instead of being limited to properties with systems smaller than 50 megawatts (MW) as in the Reference case [3]. Also, the ITC is modified to increase the eligible CHP unit cap from 15 MW to 25 MW. These extensions are consistent with previously proposed legislation.
- The extension of ethanol and biodiesel subsidies assumed in the No Sunset case is not included in the Extended Policies case, because the renewable fuel standard (RFS) program already included in the AEO2014 Reference case tends to determine the levels of ethanol and biodiesel use.

### Analysis results

The changes made to the Reference case assumptions in the No Sunset and Extended Policies cases generally lead to lower estimates for overall delivered energy consumption, increased use of renewable fuels (particularly for electricity generation), and reduced energy-related carbon dioxide ($CO_2$) emissions. Because the Extended Policies case includes most of the assumptions in the No Sunset case but adds others, the effects of the Extended Policies case tend to be greater than those of the No Sunset case (with some exceptions discussed below). Both cases result in lower energy prices, because the assumed tax credits and end-use efficiency standards lead to lower energy demand (except in the No Sunset case after 2034, as discussed below) and lower costs for renewable technologies. Appliance purchase costs are also affected. In addition, the government receives lower tax revenues as consumers and businesses take advantage of the tax credits.

Figure IF1-1. Total energy consumption in three cases, 2005-40 (quadrillion Btu)




#### Energy consumption

Total energy consumption in the No Sunset case is slightly lower than in the Reference case before 2034 and slightly higher than in the Reference case in the later years of the projection (Figure IF1-1). Improvements in energy efficiency lead to reduced consumption in the No Sunset case, but the demand-increasing effect of lower energy prices fully offsets the efficiency impacts by the end of the projection period. In 2040, total energy consumption in the Extended Policies case is 2% below the Reference case projection, as the combination of tax and other policy extensions reduces overall demand even after taking price declines into account.

#### Buildings energy consumption

Renewable distributed generation (DG) technologies (photovoltaic systems and small wind turbines) provide much of the buildings-related energy savings in the No Sunset case. The continuation of tax credits in the No Sunset case spurs increased adoption of DG systems, leading to 59 billion kWh

of onsite electricity generation from renewable DG in 2025, compared with 25 billion kWh in the Reference case. In 2040, onsite electricity generation from renewable sources increases to 145 billion kWh in the No Sunset case—almost three times the amount of onsite electricity generated in the Reference case in that year.

Similar adoption of renewable DG occurs in the Extended Policies case, while efficiency gains from assumed future standards and more stringent building codes further reduce delivered energy use in the buildings sectors. Delivered energy use for buildings in the Extended Policies case is 1.5%, or 0.3 quadrillion British thermal units (Btu), lower than in the Reference case in 2025 and 5.4%, or 1.1 quadrillion Btu, lower than in the Reference case in 2040. In the No Sunset case, in contrast, delivered energy consumption is only 1.0% (0.2 quadrillion Btu) and 1.8% (0.4 quadrillion Btu) lower than in the Reference case projections for 2025 and 2040, respectively.

Electricity use shows the largest reduction in the two alternative cases relative to the Reference case. Building electricity purchases in 2025 are 1.4% and 1.9% lower in the No Sunset and Extended Policies cases, respectively, and 2.8% and 6.9% lower, respectively, in 2040, when compared with the Reference case. Increased onsite generation decreases electricity purchases in both cases. Additional reductions in electricity purchases occur in the Extended Policies case, as assumed standards increase the market penetration of efficient equipment and building construction. Energy use for water heating in the Extended Policies case shows the largest drop relative to the Reference case, at 16% (0.4 quadrillion Btu) below the Reference case level in 2040. Space heating and cooling also are affected by the assumed standards for equipment and building codes in the Extended Policies case, and energy consumption for those uses is reduced by a combined 6.7% (0.5 quadrillion Btu) from the Reference case level in 2040. In 2040, natural gas use in the buildings sectors is 0.9% and 4.1% below the Reference case level in the No Sunset and Extended Policies cases, respectively.

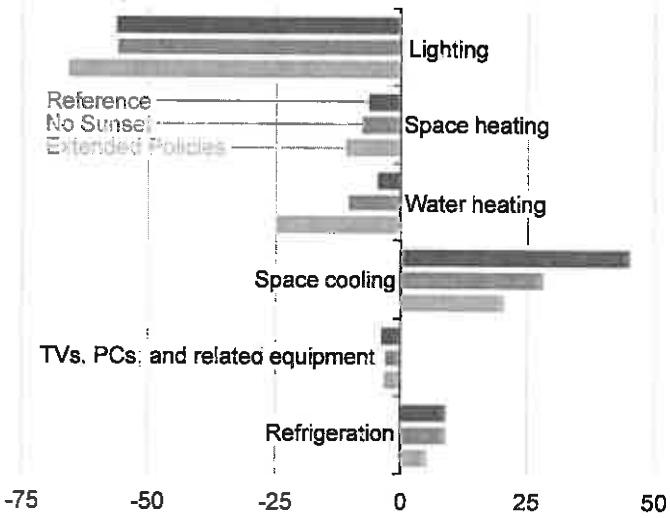
Residential energy consumption for most end uses moves in the same direction in all three cases, but at different rates (Figure IF1-2). For example, energy use for lighting, which declines in the Reference case, declines further in the Extended Policies case with additional standards; and space cooling, which increases in the Reference case, increases more slowly in the No Sunset case, which assumes the continuation of tax credits for efficient equipment and building shell thermal integrity improvement.

### Industrial energy consumption

The No Sunset case modifies the Reference case assumptions by extending the existing ITC for industrial CHP through 2040. The Extended Policies case starts from the No Sunset case and expands the credit to include industrial CHP systems of all sizes, while raising the system size limit for the maximum credit that can be claimed, from 15 MW of installed capacity to 25 MW. The changes result in 1.2 gigawatts (GW) of additional industrial CHP capacity in the Extended Policies case compared with the Reference case in 2025 and 3 GW of additional capacity in 2040.

From 2025 through 2040, more CHP capacity is installed in the Extended Policies case than in the No Sunset case, but the differences narrow over time. CHP capacity is 0.3 GW higher in the Extended Policies case than in the No Sunset case in 2025, but only 0.1 GW higher in 2040. The Extended Policies case includes a tax benefit that applies to more CHP units than in the No Sunset case, which by itself provides greater incentive to build CHP capacity. However, electricity prices are slightly lower in the Extended Policies case than in the No Sunset case starting around 2024, and the difference grows over time, which reduces the economic attractiveness of CHP. These opposite effects explain why CHP capacity in the Extended Policies case is only slightly higher than in the No Sunset case, and why the difference decreases over time. Also, the median size of the nameplate capacity of industrial CHP units is 10 MW [4], and most CHP systems are well within the 50-MW total system size, which means that relaxing the size constraint is not as strong an incentive for investment as is allowing the current tax credit for new CHP investments to continue after 2016.

Figure IF1-2. Change in residential delivered energy consumption for selected end uses in three cases, 2012-40 (percent)




Natural gas consumption in the industrial sector averages 10.4 quadrillion Btu per year from 2012 to 2040 in all three cases. However, the pattern of use varies, with the No Sunset and Extended Policies cases showing higher levels of consumption than the Reference case at the end of the projection period.

### Transportation energy consumption

The Extended Policies case differs from the Reference and No Sunset cases in assuming that the joint CAFE and greenhouse gas emissions standards promulgated by EPA and NHTSA for model years 2012 through 2025 are extended through 2040, with an assumed average annual increase of 1.3%. Sales of vehicles that do not rely solely on gasoline internal combustion engines for power (including those that use

**Effects of proposed energy provisions in the Energy Savings and Industrial Competitiveness Act of 2013**

Senate bill S. 1392, The Energy Savings and Industrial Competitiveness Act of 2013 (ESICA) [5], introduced in July 2013, contains provisions for building energy codes, industrial energy efficiency, federal agencies, and budget offsets. Assuming appropriation of the funding authorized in the bill, EIA examined two key provisions of the proposed legislation: the adoption of updated building energy codes for residential and commercial buildings, and a rebate program for energy-efficient electric motors [6]. Other provisions require further specification by federal agencies or Congress, or they address levels of detail beyond that modeled in the National Energy Modeling System. Amendments have been introduced that may have energy impacts, but they are not part of the bill as of this writing and are not considered in this analysis. Of the two provisions analyzed for AEO2014, the updated building codes have a small effect on energy consumption and $CO_2$ emissions, and the industrial motors rebate program has virtually no effect. The analysis assumes that states will take advantage of incentives offered to implement the updated codes, and that once in place the codes will be effective over time.

Compared with the AEO2014 Reference case, the proposed building codes in ESICA reduce buildings delivered energy consumption by 0.7% in 2025 and 1.1% in 2040. Natural gas shows the largest reduction in buildings' energy use relative to the Reference case, as improved building shells lessen space heating requirements. Lower energy use in the ESICA case leads to lower levels of $CO_2$ emissions than in the Reference case. From 2014 to 2040, energy-related $CO_2$ emissions are reduced by a cumulative total of 307 million metric tons (an annual average of about 12 million metric tons) relative to the Reference case projection.

Residential and commercial consumers save $9.2 billion (2012 dollars) on energy purchases in 2040 in the ESICA case relative to the Reference case, as a result of lower energy demand. From 2014 to 2040, the cumulative reduction in residential and commercial energy purchases in the ESICA case totals $96.9 billion. Some of those savings are assumed to be offset by additional costs to the buildings sectors in meeting more stringent building codes, but such costs are not comprehensively modeled by EIA. The electric motor rebate program has a minimal impact on energy use, because the proposed program is limited in terms of both authorized funding and the two-year time frame for eligible installations.

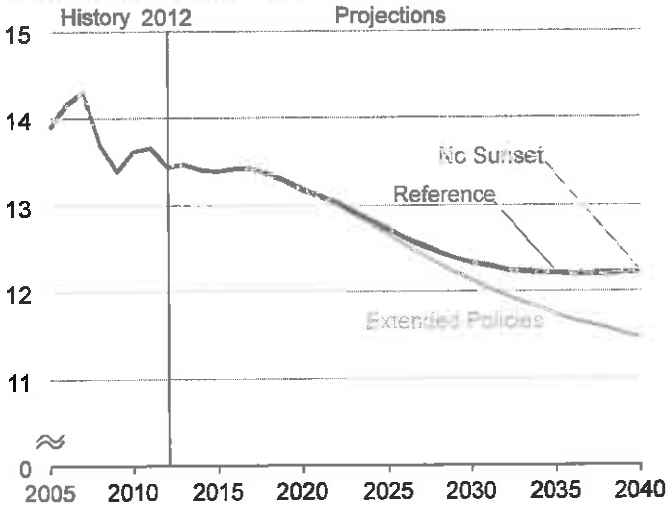
diesel, alternative fuels, or hybrid electric systems) play a substantial role in meeting the higher fuel economy standards after 2025, growing to 76% of new light-duty vehicle (LDV) sales in 2040, compared with 55% in the Reference case.

LDV energy consumption declines from 16.0 quadrillion Btu (8.7 million barrels per day [MMBbl/d] of oil equivalent) in 2012 to 13.5 quadrillion Btu (7.4 million barrels per day (MMBbl/d) of oil equivalent) in 2025 in the Reference case as a result of the increase in CAFE standards. Extension of the increases in CAFE standards in the Extended Policies case further reduces LDV energy consumption to 11.1 quadrillion Btu (6.1 MMBbl/d of oil equivalent) in 2040, which is 9% lower than in the Reference case.

The Extended Policies case differs from the Reference and No Sunset cases by extending the standards for heavy-duty vehicle (HDV) fuel consumption and GHG emissions after MY 2018. New HDV fuel economy increases from 7.7 mpg in 2018 to 8.0 mpg in 2040 in the Extended Policies case. HDV annual energy consumption still rises from 5.3 quadrillion Btu (2.5 MMBbl/d of oil equivalent) in 2012 to 6.0 quadrillion Btu (2.9 MMBbl/d of oil equivalent) in 2018 and continues to grow to 7.3 quadrillion Btu (3.5 MMBbl/d of oil equivalent) in 2040 in the Extended Policies case. However, the total is lower than the 7.5 quadrillion Btu (3.6 MMBbl/d of oil equivalent) in the Reference case in 2040.

Consumption of petroleum and other liquids in the transportation sector is nearly the same through 2025 in the Reference and Extended Policies cases but declines in the Extended Policies case from 12.7 MMBbl/d of oil equivalent in 2025 to 11.5 MMBbl/d of oil equivalent in 2040, as compared with 12.2 MMBbl/d of oil equivalent in 2040 in the Reference case (Figure IF1-3).

Figure IF1-3. Consumption of petroleum and other liquids for transportation in three cases, 2005–40 (million barrels per day)




**Renewable electricity generation**

The No Sunset and Extended Policies cases assume that tax credits for renewable electricity generation sources are extended through 2040, resulting in significantly more renewable generation—primarily from wind and solar—than in the Reference case in 2040 (Figure IF1-4). In general, renewable generation in the No Sunset case is slightly higher than in the Extended Policies case, which includes energy efficiency measures that result in slower load growth and lower demand for new generation capacity.

In the Extended Policies case, wind generation more than triples from 2012 to 2040, compared with a 76% increase in the Reference case. However, the short-term growth of wind generation in the Reference case exceeds that in the Extended Polices case, as qualification for the current production tax

credit (PTC) requires that new wind capacity be under construction by 2013 and generally in service before 2016, resulting in a near-term surge in wind capacity additions.

Minimal demand for new capacity and competitive natural gas prices limit mid-term (approximately 2015 to 2025) wind growth in all the cases, but long-term sustained growth of wind generation capacity begins earlier (in the early 2020s) and proceeds at more rapid rate in the Extended Policies case as a result of relative attractiveness of wind projects under the continued support of the PTC.

Solar generation grows at a uniformly higher rate in the Extended Policies case than in the Reference case, in response to the assumed extension of the solar investment tax credits (ITC) in the Extended Policies case that either expire or are significantly reduced after 2016 in the Reference case. In both the No Sunset and Extended Polices cases, total U.S. solar generation increases by an average of about 12% per year from 2012 to 2040, compared with 7% per year in the Reference case. In general, the relatively higher growth benefits both utility-scale PV installations in the electric power sector and customer-sited rooftop PV applications in the residential and commercial sectors. The effects of tax credit extensions on other renewable generation technologies, such as hydropower, biomass, and geothermal, are minimal in comparison.

### Energy-related $CO_2$ emissions

In the No Sunset and Extended Policies cases, lower overall fossil energy use leads to lower levels of energy-related $CO_2$ emissions than in the Reference case. In the Extended Policies case, the emissions reduction is larger than in the No Sunset case. From 2012 to 2040, energy-related $CO_2$ emissions are reduced by a cumulative total of 2.6 billion metric tons (a 1.7% reduction over the period) in the Extended Policies case relative to the Reference case, as compared with 1.2 billion metric tons (a 0.7% reduction over the period) in the No Sunset case (Figure IF1-5). The increase in fuel economy standards assumed for new LDVs in the Extended Policies case is responsible for 11.4% of the total cumulative reduction in $CO_2$ emissions from 2012 to 2040 in comparison with the Reference case. The balance of the reduction in $CO_2$ emissions is a result of greater improvement in appliance efficiencies and increased penetration of renewable electricity generation.

Most of the emissions reductions in the No Sunset case result from increases in renewable electricity generation. Consistent with current EIA conventions and EPA practice, emissions associated with the combustion of biomass for electricity generation are not counted, because they are assumed to be balanced by carbon absorption when the plant feedstock is grown. Relatively small incremental reductions in emissions are attributable to renewables in the Extended Policies case, mainly because electricity demand is lower than in the Reference case, reducing the consumption of all fuels used for generation, including biomass.

In the Extended Policies case, water heating, space cooling, and space heating together account for most of the emissions reductions from Reference case levels in the buildings sector. In the industrial sector, the Extended Policies case shows reduced emissions as a result of lower petroleum use.

### Energy prices and tax credit payments

With lower natural gas use and more consumption of renewable fuels stimulated by tax credits in the No Sunset and Extended Policies cases, natural gas and electricity prices are lower than in the Reference case. In 2040, the average delivered price for natural gas is $0.44/thousand cubic feet (Mcf), or 4.2%, lower in the No Sunset case and $0.48/Mcf, or 4.5%, lower in the Extended Policies case than in the Reference case (Figure IF1-6). Similarly, average end-use electricity prices are 0.46 cents/kWh

Figure IF1-4. Renewable electricity generation in three cases, 2012, 2020, 2030, and 2040 (billion kilowatthours)

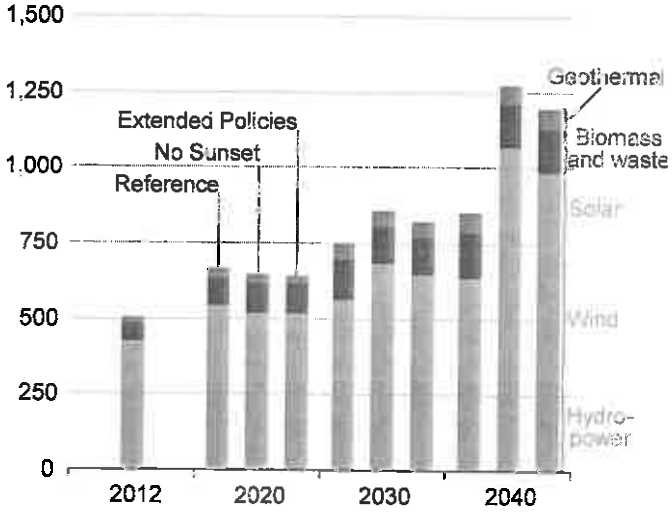
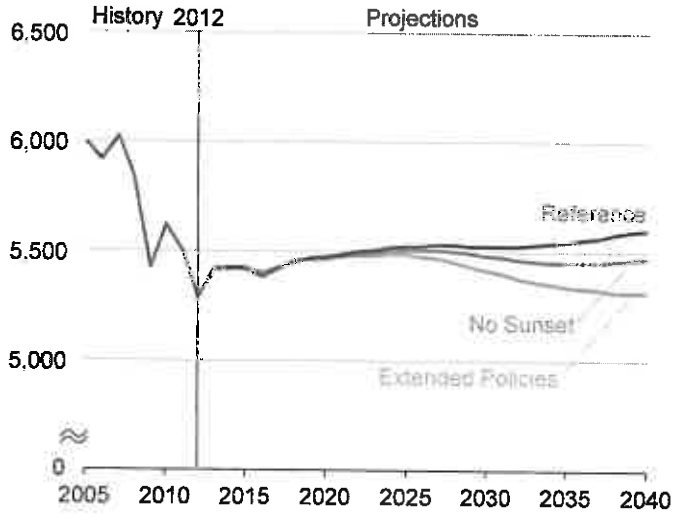



Figure IF1-5. Energy-related carbon dioxide emissions in three cases, 2005–40 (million metric tons)



(4.1%) lower in the No Sunset case and 0.55 cents/kWh (5.0%) lower in the Extended Policies cases than in the Reference case (Figure IF1-7).

The reductions in delivered energy consumption and $CO_2$ emissions in the No Sunset and Extended Policies cases are accompanied by higher equipment costs for consumers and revenue reductions for the U.S. government. Compared to the Reference case, residential and commercial consumers in the No Sunset case, on average, pay an extra $1.7 billion/year (2012 dollars) for end-use equipment, residential building shell improvements, and additional distributed generation systems between 2014 and 2040. The government, on average, pays an extra $7.7 billion/year in tax credits to consumers in the buildings sector (or, from the government's perspective, receives that amount of reduced revenue). In the Extended Policies case, consumers and the government pay, on average, an additional $14.5 billion and $5.1 billion/year, respectively, over the amounts in the Reference case between 2014 and 2040.

The additional costs to the buildings sectors in the No Sunset and Extended Policies cases are more than offset by savings on energy purchases as a result of efficiency improvements and increased distributed generation. Compared to the Reference case, residential and commercial consumers save an average of $11.9 billion (2012 dollars) in annual energy costs from 2014 to 2040 in the No Sunset case and an average of $20.4 billion annually in the Extended Policies case.

The largest response to federal tax incentives for new renewable generation in the power sector is seen in the No Sunset case, where the extension of the PTC and the 30% ITC reduces government tax revenues by approximately $4.5 billion/year from 2014 to 2040, as compared with $483 million/year in the Reference case. In the Extended Policies case, the reduction in government tax revenues is similar to, but somewhat less than, that in the No Sunset case because of the lower levels of demand. From 2014 to 2040, annual government tax revenues in the Extended Policies case will be approximately $3.3 billion/year lower than in the Reference case.

Figure IF1-6. Average delivered prices for natural gas in three cases, 2005–40 (2012 dollars per thousand cubic feet)

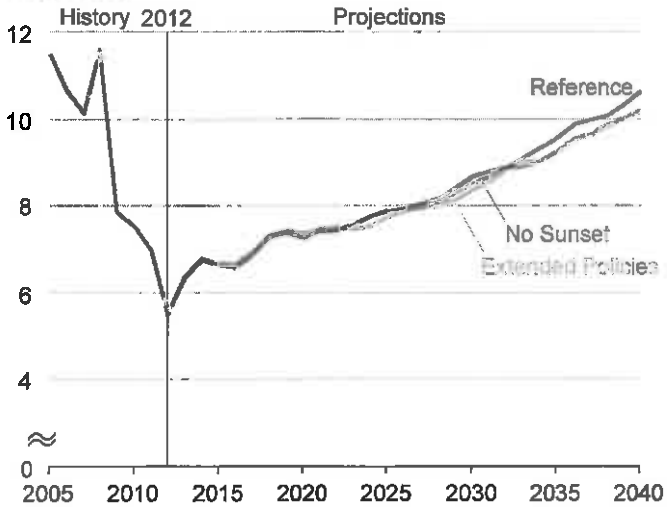
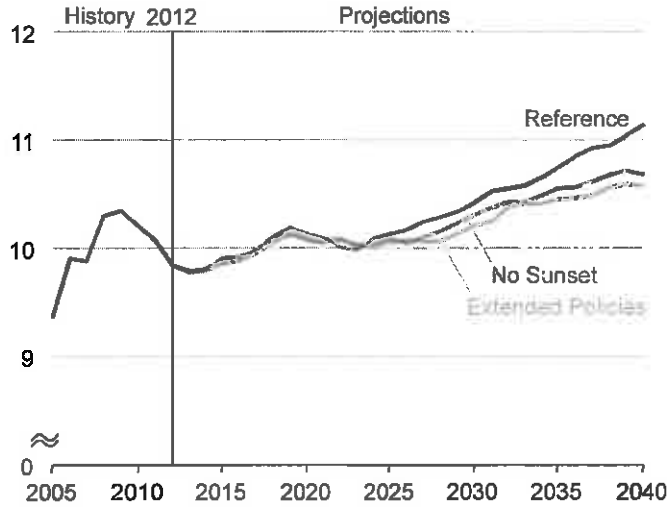



Figure IF1-7. Average electricity prices in three cases, 2005–40 (2012 cents per kilowatthour)



# Endnotes for IF1

**Links current as of April 2014**


1. United States Internal Revenue Code, Title 26, Subtitle A—Income Taxes, §48(a)(2)(A)(ii), http://www.gpo.gov/fdsys/pkg/USCODE-2011-title26/pdf/USCODE-2011-title26-subtitleA-chap1-subchapA.pdf.
2. A tax extenders package that includes a two-year extension of the biodiesel credit (retroactive to January 1, 2014) was passed by the Senate Finance Committee on April 3, 2014, but still must be passed by the House and the full Senate to become law. R. Kotrba, "Senate Finance Committee passes tax package with biodiesel credit," *Biodiesel Magazine* (April 3, 2014), http://biodieselmagazine.com/articles/41973/senate-finance-committee-passes-tax-package-with-biodiesel-credit.
3. United States Internal Revenue Code, Title 26, Subtitle A—Income Taxes, §48(c)(3)(B)(iii), http://www.gpo.gov/fdsys/pkg/USCODE-2011-title26/pdf/USCODE-2011-title26-subtitleA-chap1-subchapA.pdf.
4. Calculations based on U.S. Energy Information Administration, Form EIA-860, Schedule 3, 2011 data (Washington, DC, January 9, 2013), http://www.eia.gov/electricity/data/eia860/index.html.
5. U.S. Congress, "S. 1392 - Energy Savings and Industrial Competitiveness Act of 2013," http://beta.congress.gov/bill/113th-congress/senate-bill/1392?q=%7B%22search%22%3A%22s+1392%22%7D.
6. Modeled provisions based on S. 1392, Sections 101 and 221, as brought to the Senate floor in September 2013. An updated version of the bill was reintroduced on February 27, 2014, http://beta.congress.gov/bill/113th-congress/senate-bill/2074/text. As of this writing, time had not been scheduled for Senate floor discussion.


# Figure sources for IF1

**Links current as of April 2014**

**Figure IF1-1. Total energy consumption in three cases, 2005-40: History:** U.S. Energy Information Administration, *Monthly Energy Review September 2013*, DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

**Figure IF1-2. Change in residential delivered energy consumption for selected end uses in three cases, 2012-40: History:** U.S. Energy Information Administration, *Monthly Energy Review September 2013*, DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

**Figure IF1-3. Consumption of petroleum and other liquids for transportation in three cases, 2005-40: History:** U.S. Energy Information Administration, *Monthly Energy Review September 2013*, DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

**Figure IF1-4. Renewable electricity generation in two cases, 2012-40: History:** U.S. Energy Information Administration, *Monthly Energy Review September 2013*, DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

**Figure IF1-5. Energy-related carbon dioxide emissions in three cases, 2005-40: History:** U.S. Energy Information Administration, *Monthly Energy Review September 2013*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

**Figure IF1-6. Average delivered prices for natural gas in three cases, 2005-40: History:** U.S. Energy Information Administration, *Monthly Energy Review September 2013*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

**Figure IF1-7. Average electricity prices in three cases, 2005-40: History:** U.S. Energy Information Administration, *Monthly Energy Review September 2013*, DOE/EIA-0035(2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, NOSUNSET.D121713A, and EXTENDED.D022814A.

## IF2. U.S. tight oil production: Alternative supply projections and an overview of EIA's analysis of well-level data aggregated to the county level

U.S. production of tight oil has increased dramatically in the past few years, from less than 1 million barrels per day (MMbbl/d) in 2010 to more than 3 MMbbl/d in the second half of 2013 [1]. The *Annual Energy Outlook 2014* (AEO2014) Reference case reflects continued growth in tight oil production. However, growth potential and sustainability of domestic crude oil production hinge around uncertainties in key assumptions, such as well production decline, lifespan, drainage areas, geologic extent, and technological improvement—both in areas currently being drilled and in those yet to be drilled. As a result, High and Low Oil and Gas Resource cases were developed to examine the effects of alternate resource and technology assumptions on production, imports, and prices.

The projected trends in oil production vary tremendously in the alternative cases, and those trends hold important implications for the United States. In the High Oil and Gas Resource case, growth in tight oil production continues for a longer period of time than projected in the Reference case. Domestic crude oil production increases to nearly 13 MMbbl/d before 2035 in the High Oil and Gas Resource case, and net U.S. oil imports decline through 2036 and remain at or near zero from 2037 through 2040. The Low Oil and Gas Resource case reflects uncertainty about tight oil and shale crude oil and natural gas resources that leads to lower domestic production than in the Reference case. In this case, production reaches 9.1 MMbbl/d in 2017 before falling to 6.6 MMbbl/d in 2040, leading to higher projected dependence on net imports of petroleum and other liquids than in the Reference case. The range of production and imports in these alternative cases, as shown in Figures IF2-1 and IF2-2, illustrates the importance of uncertainty in the resource and technology assumptions.

Policymakers, industry, markets, and the public have great interest in the outlook for future domestic oil production and its key drivers. EIA continues to advance both the quality and transparency of its work in this area. Improvements made to the National Energy Modeling System (NEMS) Oil and Gas Supply Module for AEO2014 enhance its ability to capture rapid growth in tight oil production. Specifically, EIA has implemented a more disaggregated representation of estimated ultimate recovery (EUR) that uses well-level data aggregated to the county level within key producing regions to track the combined effect of technology advances and the changing quality of resources being targeted on production per well, which in turn drives an analysis of EUR for wells in each region. There is still a great deal of uncertainty in the projections of U.S. tight oil production. EIA's analysis reflects those uncertainties by varying key assumptions regarding the resource base and the rate of technology advances that lower drilling cost or raise its productivity across alternative cases. As new information is gained through drilling, production, and technology experimentation, NEMS projections for tight oil production will continue to evolve.

### Improvements in data collection and projections

The domestic oil supply outlook in AEO2014 is based on data derived from measurements at production sites that are available for analysis. Those data provide a basis for improved understanding of the key factors that have contributed to the growth of tight oil production, which has improved the analysis in AEO2014; however, limitations about the use of the data should be taken into account when the Reference case results are examined.

As individual production profiles of wells drilled in tight oil formations are developed and analyzed, they provide a basis for the calculation of a production decline curve and EUR for each well. The results can be used to project potential future production from existing wells and from new wells drilled in the same plays [2].

Figure IF2-1. U.S. crude oil production in three cases, 1960-2040 (million barrels per day)

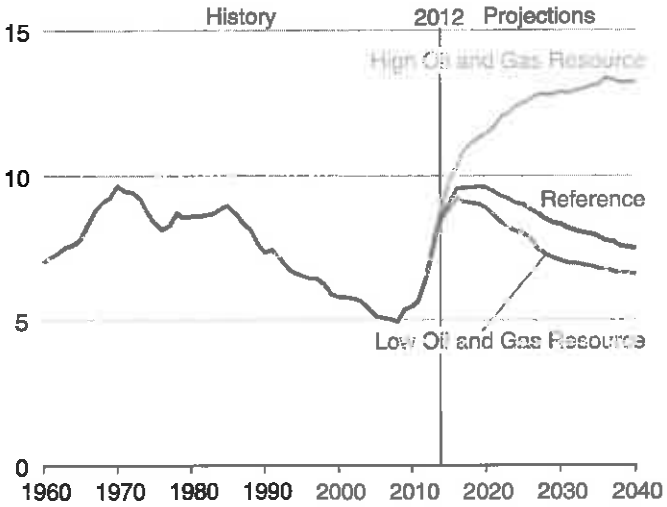
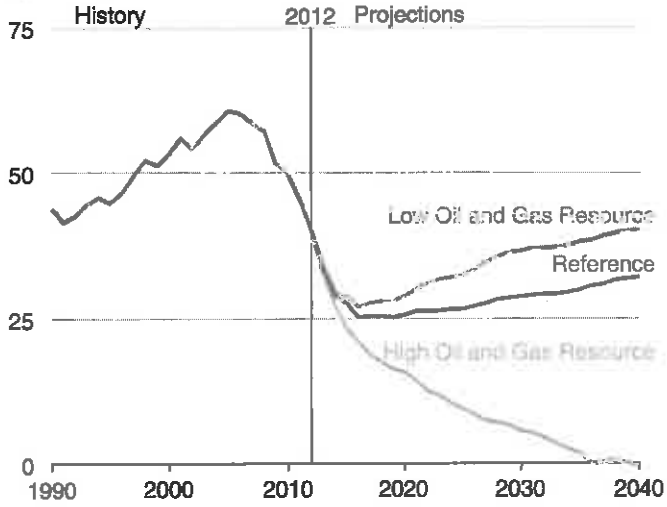



Figure IF2-2. Net import share of U.S. petroleum and other liquids consumption in three cases, 1990-2040 (percent)



Production decline curves and the associated EURs for individual wells vary widely across plays, within single plays, and even within discrete sections (counties) of a single play. Using the Eagle Ford formation in Texas as an example, the discussion below examines the methods used to estimate EURs for tight oil wells, the distribution of EURs, the factors that contribute to variations in EURs, and the implications of using county-level representations as the basis for projections of overall production totals both for oil and for natural gas, which is often a coproduct of tight oil production. Uncertainties related to EUR estimation and advances in tight oil production technologies, and their effects on projections of domestic tight oil production in the AEO2014 High and Low Oil and Gas Resource cases, are explored by scaling production decline curves.

### Estimating ultimate recovery per well

For each tight well or shale well with initial production in 2008 or later, and with at least four months of production data available, the U.S. Energy Information Administration (EIA) fits monthly production to a decline curve. The mathematical form of the curve is initially hyperbolic [3], but it shifts to exponential when the annual decline rate reaches 10% [4]. The EUR is the sum of actual past production from the well, as reported in the data, and an estimate of future production based on the fitted production decline curve over a 30-year well lifetime.

The actual production curve and the resulting actual ultimate recovery are highly uncertain and cannot be known until the well is plugged and abandoned, which may occur sooner or later than 30 years. Estimates of future production based on the first few months of initial production can differ significantly from later estimates for the same well.

As more months of production are added, the shape of the production curve and the resulting EUR for a given well can change. For example, for one well drilled in Live Oak County in the Eagle Ford formation in Texas, fitting a curve to the first year of monthly production data gave a EUR of 574,000 barrels; using four years of production data gave a EUR of 189,000 barrels for the same well. Conversely, another well in the same county had a EUR of 105,000 barrels based on the first 12 months of production data but 224,000 barrels based on four years of monthly production data. For the wells in the Eagle Ford formation with at least four years of production, EURs based on only the first year of monthly production ranged from as much as 385,000 barrels higher to 173,000 barrels lower than the EURs based on four years of production. Generally, the EUR stabilizes after three years of production, because for many wells in tight formations nearly 50% of the EUR has been produced during that period. EURs based on three years of data differ from EURs based on four years of data by 6,000 barrels on average, with a range of 65,000 barrels higher to 98,000 barrels lower. Because most Eagle Ford wells have been producing for less than three years (Table IF2-1), their EURs are likely to change as more production history is added.

### County-level representation

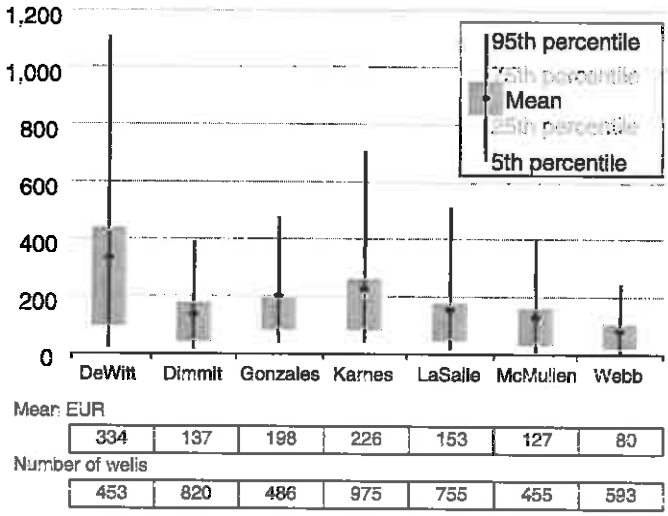
The decline curves from all wells in each county, averaged by production month, are used to generate a representative production curve that provides a basis for estimating production from future wells in that county. Wells that are newly drilled, with fewer data points and therefore greater uncertainty in the fit of their decline curves, have a tendency to inflate the average EUR. Older wells, which may have been drilled and completed using technologies and practices that are no longer representative of future practices, tend to pull the average down.

The range of EURs within a given county can be large, as shown in Figure IF2-3 for the seven counties in the Eagle Ford formation that have more than 400 oil and natural gas wells. Some wells have high initial production, but because they have been producing for less than a year, their EURs are highly uncertain. These few high-performing wells raise the county mean EUR above the county median EUR, generally skewing the mean toward the 75th percentile.

Table IF2-1. Average estimated ultimate recovery for wells in the Eagle Ford formation starting production between January 2008 and June 2013 and with at least four months of production

| Vintage year | Number of wells | Average EUR (thousand barrels) |
|---|---|---|
| 2008 | 33 | 36 |
| 2009 | 75 | 57 |
| 2010 | 514 | 117 |
| 2011 | 1,627 | 153 |
| 2012 | 2,717 | 191 |
| 2013 | 418 | 169 |
| All years | 5,384 | 168 |

Figure IF2-3. Distribution of estimated ultimate recovery per well in seven counties in the Eagle Ford formation, 2013 (thousand barrels)



The Eagle Ford formation covers 32 counties in Texas. In 14 of those counties, fewer than 10 wells had been drilled as reported through June 2013. The EUR for counties with little or no drilling is assumed to be equal to the average of the mean estimates from adjacent counties [5]. The Eagle Ford county-level EURs range from more than 300,000 barrels per well (DeWitt county) to less than 25,000 barrels per well (Burleson and Maverick counties), with a mean average of roughly 170,000 barrels per well and a median of 103,000 barrels per well across all the Eagle Ford counties.

The county-level representation derived from well-level data implemented in AEO2014 allows the model to reflect rapid growth in production for plays in the early years of development, when producers focus on developing the most productive wells in the formation's sweet spots [6], the plateau in production as new drilling offsets the decline in production from older wells, and an eventual decline in production as development moves to less-productive areas (Figure IF2-4). However, there is still a great deal of uncertainty underlying the recovery of tight oil in known plays, as well as the potential for production from additional plays or other layers within a currently productive formation that has not been tested. The application of refinements to current technologies, as well as new technology advances, can also have significant (but uncertain) impacts on the recoverability of tight and shale crude oil.

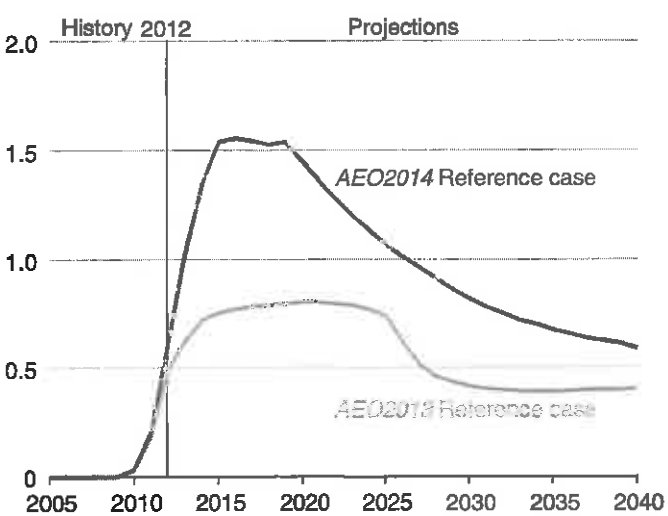
### High and Low Resource cases

The High and Low Oil and Gas Resource cases in AEO2014 were developed using assumptions that result in higher and lower estimates of technically recoverable crude oil and natural gas resources than those in the Reference case [7]. These cases allow for an examination of the potential impacts of higher and lower domestic supply on energy demand, imports, and prices, but they do not represent upper and lower bounds for future domestic oil and natural gas supply. The two cases are not symmetric; currently, there is more uncertainty about the potential for greater gains in production than about the potential for lower production levels.

The High Oil and Gas Resource case assumes a broad-based future increase in crude oil and natural gas resources, not limited to production of oil and natural gas in tight sands and shales. However, optimism about increased supply has been buoyed by recent advances in the production of crude oil and natural gas from tight and shale formations. With the adjusted resource and technology advance assumptions in the High Oil and Gas Resource case, domestic crude oil production continues to increase to more than 13 MMbbl/d before 2035. Specific assumptions for the High Oil and Gas Resource case, as compared with the Reference Case, include:

- EURs for tight oil, tight gas, and shale gas wells are 50% higher [8]
- Additional tight oil resources as well as 50% lower well spacing (i.e., wells are closer together), with a downward limit of 40 acres per well for existing and potential future tight oil resources, to capture the possibility that additional layers or new areas of low-permeability zones will be identified and developed
- Diminishing returns on the EUR when drilling in a county exceeds the number of potential wells assumed in the Reference case [9], to capture the probability that greater drilling density will cause wells to interfere with each other (i.e., production from one well might reduce production from a nearby well)
- Long-term technology improvements beyond those assumed in the Reference case, represented as a 1% annual increase in the EURs for tight oil, tight gas, and shale gas wells

Figure IF2-4. Eagle Ford crude oil production in the Reference case, 2005-40 (million barrels per day)




- More resources in Alaska and in the lower 48 offshore, including the development of tight oil in Alaska and 50% higher technically recoverable undiscovered resources for other Alaska crude oil and the lower 48 offshore (which reflects more favorable resolution of the uncertainty surrounding undeveloped areas where there has been little or no exploration and development activity, and where modern seismic survey data are lacking)
- The development of lower 48 onshore oil shale (kerogen), with production reaching 135,000 barrels per day by 2025.

The High Oil and Gas Resource case does not include exploration or production activity in the Arctic National Wildlife Refuge.

The Low Oil and Gas Resource case reflects only the uncertainty around tight and shale crude oil and natural gas resources—specifically, whether the performance of current and future wells drilled will actually be less than estimated. For the Low Oil and Gas Resource case, the EUR per tight and shale well is assumed to be 50% lower than in the AEO2014

Reference case (by scaling all applicable production decline curves). All other resource assumptions are unchanged from the Reference case.

### Effects on domestic crude oil production

The difference in overall production across cases mostly reflects differences in tight oil projections. In the High Oil and Gas Resource case, higher well productivity reduces development and production costs per unit, which results in more and earlier development of tight oil resources than in the Reference case. The greater abundance of tight oil resources in the High Oil and Gas Resource case causes tight oil production to peak later in the projections, at 8.5 MMbbl/d in 2035, compared to the Reference case peak production rate of 4.8 MMbbl/d in 2021. From 2012 through 2040, cumulative tight oil production in the High Oil and Gas Resource case amounts to 75 billion barrels, compared with 44 billion barrels in the Reference case.

In the Low Oil and Gas Resource case, lower estimates of tight oil, tight gas, and shale gas resources result in a U.S. production profile that is both slower and lower than in the Reference case, with tight oil production peaking at 4.3 MMbbl/d in 2016 and then declining through 2040. Cumulative tight oil production from 2012 through 2040 amounts to 34 billion barrels in the Low Oil and Gas Resource case, which is 23% less than in the Reference Case.

### Effects on U.S. net imports of petroleum and other liquids

The variations in projected domestic petroleum supply between the Reference case and the High and Low Oil and Gas Resource cases result in significant variations in the share of net imports in total U.S. liquid fuels consumption (Figure IF2-2). The net import share of petroleum and other liquids consumption, which increased steadily from 27% in 1985 to about 60% in 2005, has fallen since 2005, to roughly 40% in 2012. In the Reference case, the share of U.S. petroleum and other liquids consumption met by imports continues declining to 25% in 2016, and then begins a gradual increase starting in 2020, reaching 32% in 2040. The net import share follows a similar trend in the Low Oil and Gas Resource case, falling to 27% in 2016 and then rising to 40% in 2040. In contrast, net import dependence continues to decline through 2036, and it is at or near zero from that point until 2040 in the High Oil and Gas Resource case.

### Effects on prices

As a result of higher levels of U.S. crude oil production in the High Oil and Gas Resource case, North Sea Brent crude oil prices are lower than in the Reference case: $125 per barrel (2012 dollars) in 2040, compared with $141 per barrel in 2040 in the Reference case. Lower motor gasoline and diesel prices in the transportation sector encourage more consumption.

In the Low Oil and Gas Resource case, lower levels of domestic crude oil production result in a slightly higher Brent crude oil price than in the Reference case—$145 per barrel (2012 dollars) in 2040. As noted above, because the uncertainty around production increases is greater than the uncertainty around production decreases, assumptions in the Low Oil and Gas Resource case are closer to the assumptions in the Reference case than are the assumptions in the High Oil and Gas Resource case.

## Endnotes for IF2

**Links current as of April 2014**

1. The term tight oil does not have a specific technical, scientific, or geologic definition. Tight oil is an industry convention that generally refers to oil produced from very low permeability shale, sandstone, and carbonate formations, with permeability being a laboratory measure of the ability of a fluid to flow through the rock. In limited areas of some very low permeability formations, small volumes of oil have been produced for many decades.
2. A play is defined as a set of known or postulated oil and gas accumulations sharing similar geologic, geographic, and temporal properties, such as source rock, migration pathway, timing, trapping mechanism, and hydrocarbon type.
3. The hyperbolic decline curve is given by $Q_t = Q_i / [(1 + bD_it)^{1/b}]$, where $Q_t$ is the production volume in time $t$ (in months), $Q_i$ is the initial volume at time 0 (the 30-day initial production rate or IP is $Q_i$), $D_i$ is the initial decline rate, and $b$ is the hyperbolic parameter ($b$ of 0.001 is basically an exponential decline). Because the reported production in the first month could include 1 to 31 days of actual production, the first-month data are excluded from the fitting routine.
4. Of the 6,594 Eagle Ford wells included in the Drillinginfo database, 927 were excluded because they had less than four months of production data—leaving 5,667 to be evaluated through the automated fitting routine. For 95% of the wells, monthly production was fitted successfully to a hyperbolic decline curve.
5. Planned future enhancements to this methodology include taking into account any available geologic information (i.e., porosity, depth, thickness, total organic carbon, thermal maturity, and natural fracture density and location) to provide appropriate weights for the adjacent county EURs.
6. Sweet spot is an industry term for those selected and limited areas within a play where the well EURs are significantly higher than those for the rest of the play—sometimes as much as 10 times higher than those for the lower production areas within the play.
7. The total unproved technically recoverable crude oil resources are 401 billion barrels in the High Oil and Gas Resource case and 180 billion barrels in the Low Oil and Gas Resource case, compared to 209 billion barrels in the Reference case. Total unproved technically recoverable dry natural gas resources are 3,349 trillion cubic feet (Tcf) in the High Oil and Gas Resource case and 1,480 Tcf in the Low Oil and Gas Resource case, compared to 1,932 Tcf in the Reference case.
8. This is achieved by scaling the applicable production decline curves upward.
9. For this assumption, the initial production rate is increased by 20%, but the decline curve is shifted so that the overall EUR is reduced by 20%.

## Figure and table sources for IF2

**Links current as of April 2014**

**Figure IF2-1. U.S. crude oil production in three cases, 1960-2040: History:** U.S. Energy Information Administration. Monthly Energy Review September 2013, DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

**Figure IF2-2. Net import share of U.S. petroleum and other liquids consumption in three cases, 1990-2040: History:** U.S. Energy Information Administration. Monthly Energy Review September 2013, DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

**Table IF2-1. Average EUR for wells in the Eagle Ford formation starting production between January 2008 and June 2013 and with at least four months of production:** U.S. Energy Information Administration.

**Figure IF2-3. Distribution of estimated ultimate recovery per well in seven counties in the Eagle Ford formation, 2013:** U.S. Energy Information Administration.

**Figure IF2-4. Eagle Ford crude oil production in the Reference case, 2005-40: History:** U.S. Energy Information Administration. **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A, and AEO2013 National Energy Modeling System, run REF2013.D102312A.

## IF3. Potential of liquefied natural gas as a freight locomotive fuel

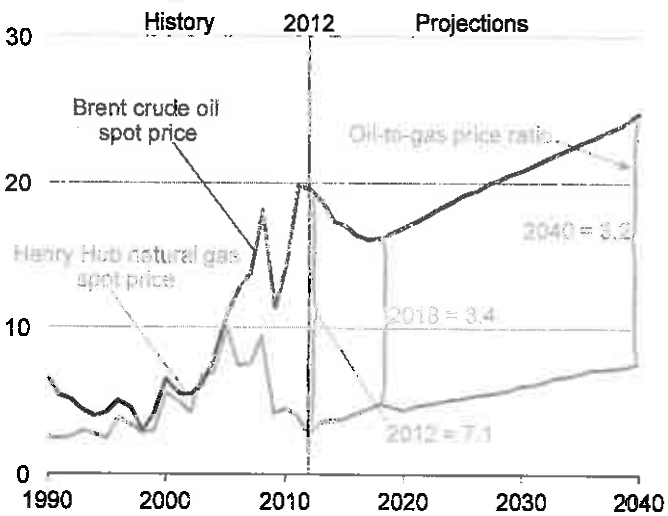
Continued growth in domestic natural gas production, along with substantially lower natural gas spot prices compared to crude oil, is reshaping the U.S. energy economy and attracting considerable interest in the potential for fueling freight locomotives with liquefied natural gas (LNG). While there is significant appeal for major U.S. railroads to use LNG as a fuel for locomotives because of its potentially favorable economics compared with diesel fuel, there are also key uncertainties as to whether, and to what extent, the railroads can take advantage of this relatively cheap and abundant fuel.

### Freight railroads and the basic economics of fuel choice

Major U.S. railroads, known commonly as Class 1 railroads, are defined as line-haul freight railroads with certain minimum annual operating revenue. Currently, that classification is based on 2011 operating revenue of $433.2 million or more [1]. While there are 561 freight railroads operating in the United States, only seven are defined as Class 1 railroads. The Class 1 railroads account for 94% of total freight rail revenue [2]. They haul large amounts of tonnage over long distances, and in the process they consume significant quantities of diesel fuel. In 2012, the seven Class 1 railroads consumed more than 3.6 billion gallons (gal) of diesel fuel [3], amounting to 10 million gal/day and representing 7% of all diesel fuel consumed in the United States. The two largest consumers of diesel fuel among the Class 1 railroads—Burlington Northern Santa Fe (BNSF) and Union Pacific—consumed more than 1 billion gal each in 2012. The cost to Class 1 railroads of consuming such large quantities of diesel fuel was more than $11 billion in 2012, representing 23% of their total operating expense (Table IF3-1).

Class 1 railroads are considering the use of LNG to fuel locomotives because of the potential for significant cost savings. Following years of tight price linkage, spot prices for crude oil (North Sea Brent) and natural gas (Henry Hub) diverged around 2005. In 2012, the Brent spot price was about seven times the Henry Hub spot price on an energy equivalent basis. That differential is projected to narrow in the midterm, but a persistent gap is expected to continue, with crude oil prices more than three times higher than natural gas per million British thermal units (MMBtu) throughout the Reference case projection period, going out to 2040 (Figure IF3-1).

Figure IF3-1. Comparison of spot prices for Brent crude oil and Henry Hub natural gas, 1990-2040 (2012 dollars per million Btu)




The large differential between crude oil and natural gas commodity prices translates directly into a significant disparity between projected LNG and diesel fuel prices, even after accounting for natural gas liquefaction costs that exceed refining costs. In the AEO2014 Reference case, the long-run price difference between locomotive diesel fuel and LNG in rail applications increases from $1.48/gal of diesel equivalent in 2014 to $1.77 in 2040 (Figure IF3-2).

Given the difference between LNG and diesel fuel prices in the Reference case, railroads that switch locomotive fuels could accrue significant fuel cost savings. Locomotives are used intensively, consume large amounts of fuel, and are kept in service for relatively long periods of time. The net present value of future fuel savings across the Reference case projection for an LNG locomotive compared to a diesel counterpart is well above the roughly $1 million higher cost of the LNG locomotive and tender (Figure IF3-3).

Relatively large changes in assumptions used to evaluate investments in LNG locomotives (such as a significantly shorter payback period or much higher discount rate) or in

Table IF3-1. Class 1 railroad diesel fuel consumption, fuel cost, and fuel cost share of operating expense, 2012

| Class 1 railroad (2012) | Diesel fuel consumption (gallons) | Fuel cost (thousand 2012 dollars) | Fuel cost share of total operating expense |
|---|---|---|---|
| Burlington Northern Santa Fe | 1,335,417,552 | $4,273,779 | 29% |
| Union Pacific | 1,108,029,359 | $3,505,671 | 24% |
| CSX Transportation | 490,902,017 | $1,542,747 | 18% |
| Norfolk Southern | 462,466,433 | $1,437,178 | 18% |
| Canadian National Grand Trunk | 101,555,124 | $326,303 | 16% |
| Canadian Pacific Soo | 71,575,774 | $231,211 | 16% |
| Kansas City Southern | 64,078,412 | $195,428 | 22% |
| **Total** | **3,634,024,671** | **$11,512,317** | **23%** |

fuel prices would be required to change LNG fuel economics for railroad use from favorable to unfavorable. Starting from the Reference case, the economics for switching to LNG locomotives remain favorable unless the payback period is reduced by eight years or the discount rate applied is raised by nine percentage points (Figure IF3-4). However, in the Low Oil Price case, the net present value of fuel cost savings associated with LNG use are not large enough to offset the higher additional upfront cost of LNG locomotives and tenders (Figure IF3-5). The shortfall in the value of fuel savings relative to upfront investment increases over the projection period in this case, making investments in LNG fueling less attractive over time. Clearly, uncertainty about future fuel prices suggests that there is some risk for companies in making such a fundamental change in freight rail operations.

### Challenges for liquefied natural gas as a freight rail fuel

While simple economic calculations involving the comparison of fuel cost savings to additional upfront cost are relatively straightforward, other factors, including operational, financial, regulatory, and mechanical challenges, also affect fuel choices by railroads. One of the most challenging factors raised by the switch to LNG locomotives by Class 1 railroads is the effect on operations. Switching from diesel fuel to LNG would require a new delivery infrastructure for locomotive fuel. Natural gas would need to be delivered to fuel depots, either by truck in smaller quantities, as LNG [4], or perhaps by pipeline. Larger quantities of

Figure IF3-2. Comparison of prices for railroad diesel fuel and liquefied natural gas fuel, 2014-40 (2012 dollars per gallon diesel equivalent)

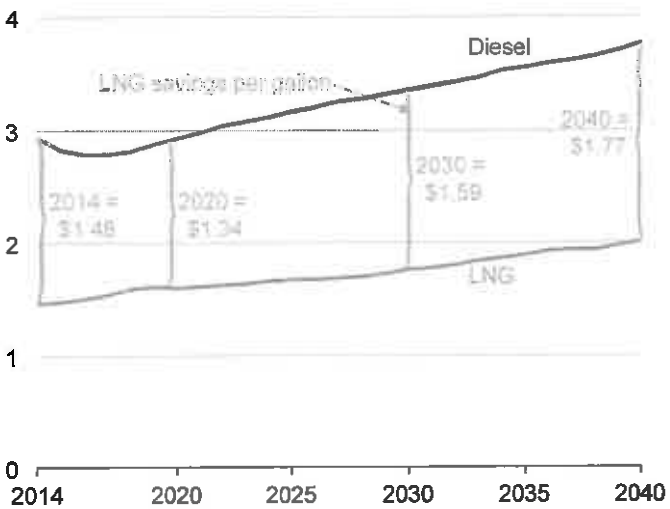



Figure IF3-3. Discounted fuel cost savings for a new locomotive and tender using liquefied natural gas as a fuel compared to diesel, 2020-40 (million 2012 dollars, net present value)

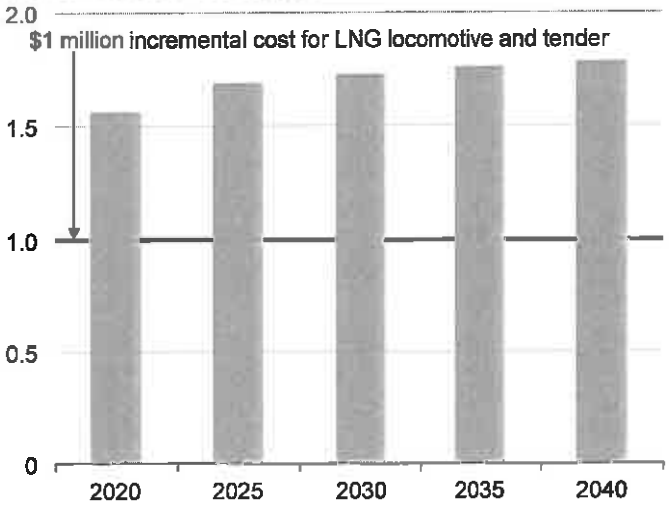



Figure IF3-4. Net present value calculation for locomotives using liquefied natural gas at Reference case fuel prices (payback years and discount rate)

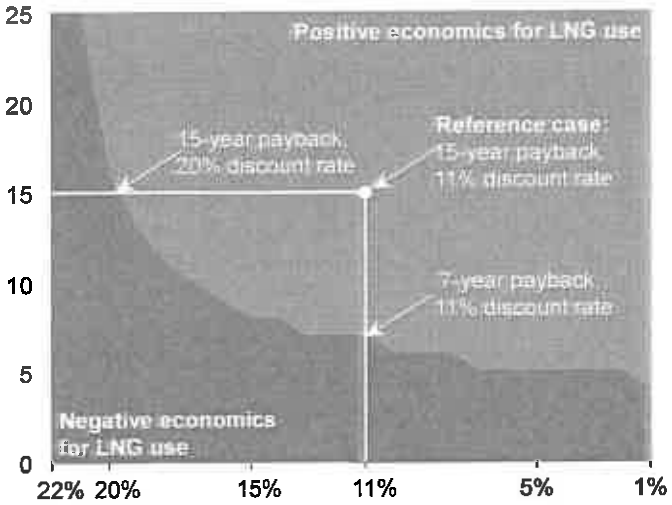
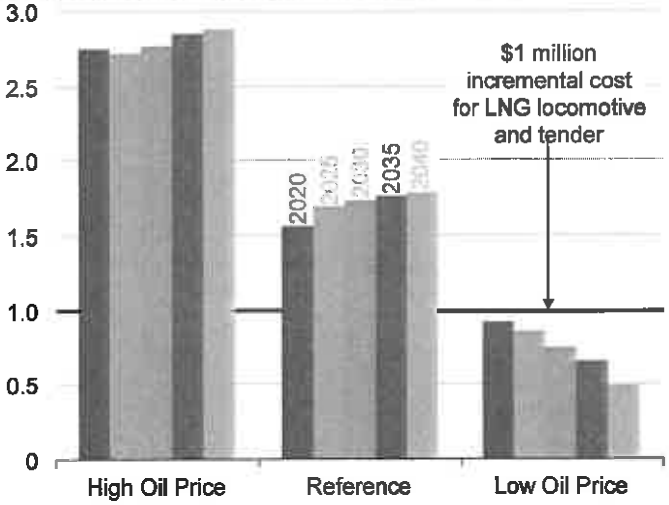



Figure IF3-5. Discounted average fuel cost savings for a new locomotive and tender using liquefied natural gas as a fuel compared to diesel in three cases, 2020-40 (net present value, million 2012 dollars)



natural gas would require liquefaction before delivery to tender cars for use in locomotives. Building the new infrastructure would require a large financial investment in addition to the large investments made in locomotives and tender cars.

The building of LNG refueling infrastructure could also complicate the inter-operability of the rail network, depending on how quickly modifications could be made to accommodate refueling at multiple points around the nation. Impeding the ability of the rail network system to move goods because of a lack of fuel availability could drive up costs and lead to reductions in network flexibility and operational efficiency [5]. In addition, operations could be further affected by fuel switching because of the cost of training staff at refueling depots and in maintenance shops, updating maintenance facilities to handle LNG locomotives and tenders, and managing more extensive logistics [6]. Further, LNG locomotives and tender cars could require more maintenance than their diesel counterparts. All of these operational changes would create a duplicative infrastructure [7], because many diesel-fueled locomotives still would be in service at least for some significant period, and compression-ignited LNG locomotives still require at least some diesel fuel for combustion ignition.

Replacing the current stock of diesel locomotives with LNG locomotives and tender cars would represent a significant financial investment by Class 1 railroads. In 2012, there were 25,174 locomotives in the service of Class 1 railroads, the vast majority of which were line-haul locomotives [8]. A new diesel line-haul locomotive costs about $2 million [9], and rebuilt locomotives cost about half that amount. With a new LNG locomotive and tender costing about $1 million more than a diesel counterpart, the cost to replace the entire diesel locomotive stock with LNG locomotives and tenders would be tens of billions of dollars, not including additional infrastructure, training, logistics, and a potential increase in maintenance costs. Moreover, much of the cost of the transition, such as purchases of locomotives and tender cars, potentially would occur over a much shorter time period than a fuel payback period.

The financing requirement of large capital expenditures complicates the rather straightforward calculation of locomotive fuel economics. The amount of capital available to Class 1 railroads, either on hand or raised in capital markets, is an important factor in determining whether, or to what extent, railroads can take advantage of fuel cost savings over time. The decision to switch from diesel fuel to LNG is also influenced by the facts that railroads are a highly capital-intensive industry [10] with complete responsibility for maintaining the physical rail network, that they face many competing needs for financial investment, and that they must ensure adequate return on investment for their shareholders.

On the regulatory side, LNG rail cargos currently are not permitted without a waiver from the Federal Railroad Administration (FRA) under Federal Emergency Management Agency (FEMA) rules. The development of standard LNG tenders and regulations is underway, with issues related to safety, crashworthiness, and environmental impact, including methane leakage, under consideration [11].

Finally, LNG locomotives currently are undergoing extensive testing and demonstration to determine their fuel consumption, emissions, operational performance, and range under real-world conditions. Locomotives and tenders will be evaluated to ensure mechanical performance of such components as connections between tender and locomotive. Several Class 1 railroads are planning to start LNG locomotive demonstration projects to provide better understanding of the obstacles to an LNG fuel switch.

### The future of liquefied natural gas in freight rail: lessons from history

The large potential fuel cost savings from the switch to LNG locomotives from diesel has resulted in great interest on the part of the freight rail industry, observers, and analysts. The companies have discussed the potential of LNG as comparable with the switch from steam propulsion to diesel in the 1940s and 50s [12], a revolution in freight rail known simply as "dieselization." Other industry experts have responded with more caution, likening the switch to the more evolutionary transformation of diesel-electric freight rail locomotives from direct current (DC) to alternating current (AC) propulsion that has been occurring since the early 1990s [13].

The diesel revolution in rail began in yard-switching operations during the mid-1920s, followed by passenger rail in the mid-1930s. After an initial period of hesitation, mainly because of the vast amount of capital already invested in steam locomotives and their refueling and watering infrastructure, diesel freight locomotives first appeared in 1941. They then captured the market at an extraordinary rate, with the last steam locomotive mustered out of service in 1961 [14].

The advantages of using diesel locomotives over steam were numerous. While diesel locomotive costs were about double per horsepower compared to steam, diesel locomotives proved superior in almost every other way. Steam locomotives had to slow or stop to take on water, requiring extensive watering infrastructure, and they needed nearly constant cleaning, maintenance, and repair, with annual costs reaching 25% of the initial cost of the locomotive. The switch to diesel allowed the railroads to avoid costly watering time and infrastructure and dramatically reduced maintenance and repair. As a result, diesel engines could travel faster and thus double the annual mileage of steam locomotives. Diesel engines, unlike steam engines, could be turned on and off with relative ease: a lead diesel locomotive could control other locomotives on a unit train; the costs of rail line maintenance were reduced because diesel locomotives were lighter and did not "pound the tracks"; and maintenance costs were lowered by the use of standardized parts and design [15].

Although diesel freight locomotives took over the market in 20 years, freight locomotives with AC traction motors, which began service in Class 1 railroads in the early 1990s, represent about 17% of the locomotive stock today [16]. AC locomotives have

the major advantage of greater adhesion levels than their counterparts equipped with DC motors, allowing fewer locomotives to pull the same load. The ability to reduce the number of locomotives pulling a unit train represents a significant improvement in fuel efficiency, but it has not been adopted to the same extent as dieselization. Class 1 railroads have gradually adopted or decided against AC traction for a variety of reasons related to operations, upfront incremental costs, and the ability to take advantage of increased adhesion levels. For example, in recent years Union Pacific, Canadian Pacific, and CSX have chosen AC traction locomotives because of locomotive unit reductions, reliability, interoperability, and life-cycle costs. Canadian National Grand Trunk and Norfolk Southern have stayed with DC traction because of incremental cost and the inability to apply unit train reductions. BNSF has chosen AC locomotives for coal runs, where they can take advantage of unit locomotive reductions, and DC locomotives for intermodal runs, where they cannot [17].

These historical examples of the impacts of new technologies and fuels may offer insights into the future potential for LNG locomotives. As happened during the diesel revolution, freight railroads may adopt a completely new locomotive fuel and infrastructure over two decades if there is a compelling business case. However, many cost and operational efficiencies made diesel locomotives superior to steam locomotives, and the same dynamic may not be seen with LNG. Moreover, investment in existing capital stock and relevant equipment may be an impediment early in a transformation process.

The ongoing evolution of AC traction locomotives shows that Class 1 railroads will invest in a new locomotive technology, at least gradually, if there is significant reason to do so. The decision may balance factors such as cost with operational efficacy.

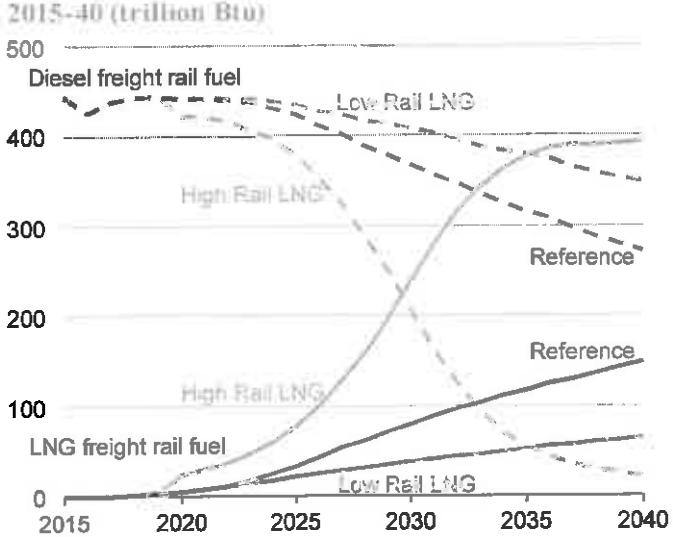
### Liquefied natural gas in freight rail—revolution and evolution cases

AEO2014 includes two alternative cases that examine the potential impact of LNG in freight rail, based on the diesel revolution and AC traction evolution. The cases also look at the impact of a specific LNG engine technology. The High Rail LNG case represents a revolution in freight rail locomotive fueling similar to that of dieselization in the 1940s and 1950s. After an initial trial period starting in 2017 through 2020, Class 1 railroads take advantage of the favorable economics of LNG locomotive fuel such that after a 20-year period, all freight rail motive stock is converted to LNG capability. The new locomotives are assumed to use high-pressure direct injection (HPDI) LNG engine technology, which uses natural gas as the primary fuel and relies on a small amount of diesel fuel for ignition. HPDI engines use fuel at a ratio of about 95% LNG to 5% diesel. LNG-only engines are not expected to be adopted for locomotives.

The Low Rail LNG case represents an evolution in freight rail locomotive fueling similar to the ongoing penetration of AC traction locomotives. After an initial trial period from 2017 through 2020, Class 1 railroads take advantage of the favorable LNG locomotive fuel economics by turning over their engine stocks at an average rate of 1% per year. The new LNG locomotives are assumed to use a dynamic gas blending engine, which uses diesel fuel for combustion until intake temperature rises, at which point natural gas is used. The engines are LNG-capable up to a fuel consumption ratio of 80% LNG and 20% diesel and have the added advantage of being dual-fuel compatible, with the ability to switch back to 100% diesel fuel as needed. The Reference case does not make any assumption about the type of LNG engine used but instead allows LNG to penetrate into freight rail at the average annual turnover rate of new and rebuilt stock experienced over the last decade.

The High and Low Rail LNG cases show a dramatic change in the fuel mix used by freight rail. In the Reference case, LNG fuel use increases from 0.5 trillion Btu in 2017 to 148 trillion Btu in 2040, or 35% of total freight rail energy consumption (Figure IF3-6). In the High Rail LNG case, LNG fuel consumption increases to 392 trillion Btu in 2040, or 95% of freight rail energy consumption. LNG consumption in the Low Rail LNG case increases to just 64 trillion Btu, or 16% of total freight energy consumption.

Figure IF3-6. Comparison of energy consumption for freight rail using diesel and LNG in three cases, 2015-40 (trillion Btu)




While the impacts are dramatic in the freight rail sector, it is important to note that the impacts on total energy use in the U.S. transportation system and on the nation's total energy consumption are relatively small. In the Reference case, transportation diesel consumption increases from about 6 quadrillion Btu in 2012 to 6.5 quadrillion Btu in 2017 and 7.5 quadrillion Btu in 2040, with railroad diesel use of 0.5 quadrillion Btu in 2012 decreasing to 0.4 quadrillion Btu in 2017 and 0.3 quadrillion Btu in 2040, when LNG accounts for 35% of projected energy use by freight rail in the Reference case. Most transportation diesel fuel consumption—more than 80%—occurs in heavy-duty vehicles. Because freight rail accounts for only a small share of transportation diesel use, projected total transportation diesel fuel use in 2040 varies only modestly across cases with different levels of LNG use in freight rail, ranging from 7.3 quadrillion Btu in the High Rail LNG case to 7.6 quadrillion Btu in the Low Rail LNG case.

Projected natural gas consumption for transportation (excluding pipeline transportation) is sensitive to variation in freight rail use of LNG, because relatively small amounts of natural gas currently are consumed in mobile applications either as compressed or liquefied natural gas. Natural gas consumption in the transportation sector (including pipeline transportation) increases from 0.9 quadrillion Btu in 2040 in the Reference case to 1.1 quadrillion Btu in the High Rail LNG case and to 0.8 quadrillion Btu in the Low Rail LNG case. The projected changes in use of LNG in rail have marginal impacts on retail natural gas prices in the transportation sector, which impact natural gas demand in other transportation uses. As a result of these price changes, heavy-duty truck natural gas demand partially offsets the consumption impacts occurring in rail.

Because the transportation sector is a relatively small consumer of natural gas compared to other sectors, the seemingly dramatic fuel switch from the perspective of freight rail is only a minor change in overall U.S. natural gas consumption. Total U.S. natural gas energy consumption varies from 32.3 quadrillion Btu in 2040 in the Reference case to 32.4 quadrillion Btu in the High Rail LNG case and 32.1 quadrillion Btu in the Low Rail LNG case.

# Endnotes for IF3

**Links current as of April 2014**


1. Association of American Railroads, *Class I Railroad Statistics* (July 9, 2013), https://www.aar.org/StatisticsAndPublications/Documents/AAR-Stats-2013-07-09.pdf. Accessed January 23, 2014.
2. S.C. Davis, S.W. Diegel, and R.G. Boundy, *Transportation Energy Databook: Edition 32*, ORNL-6989 (Oak Ridge, TN, July 2013), Chapter 9, Table 9.8, "Summary Statistics for Class 1 Freight Railroads, 1970-2011."
3. U.S. Department of Transportation, Surface Transportation Board, *Annual Reports Financial Data*, http://www.stb.dot.gov/econdata.nsf/f03952607fcc0f8e85256660b006870c97Open/view.
4. W.C. Vantuono, "A Closer Look at LNG," *Railway Age* (October 2013).
5. BNSF Railway Company, Union Pacific Railroad Company, Association of American Railroads, and California Environmental Associations, *An Evaluation of Natural Gas-fueled Locomotives* (November 2007).
6. W.C. Vantuono, "A Closer Look at LNG," *Railway Age* (October 2013).
7. BNSF Railway Company, Union Pacific Railroad Company, Association of American Railroads, and California Environmental Associations, *An Evaluation of Natural Gas-fueled Locomotives* (November 2007).
8. U.S. Department of Transportation, Surface Transportation Board, *Annual Report Financial Data* (2012 and various years), http://www.stb.dot.gov/econdata.nsf/f03952607fcc0f8e85256660b006870c97Open/view.
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11. W.C. Vantuono, "A Closer Look at LNG," *Railway Age* (October 2013).
12. K. Smith, "LNG: fuel of the future?" *International Railway Journal* (December 9, 2013), http://www.railjournal.com/index.php/locomotives/lng-fuel-of-the-future.html.
13. W.C. Vantuono, "A Closer Look at LNG," *Railway Age* (October 2013).
14. This summary of many of the major factors related to the switch from steam locomotives to diesel locomotives is taken from C. Wolmar, *The Great Railroad Revolution: The History of Trains in America* (Perseus Books Group, 2012), ISBN 978-1-61039-179-5.
15. C. Wolmar, *The Great Railroad Revolution: The History of Trains in America* (Perseus Books Group, 2012), ISBN 978-1-61039-179-5.
16. W.C. Vantuono, "A Closer Look at LNG," *Railway Age* (October 2013).
17. Electro Motive Diesel, "The Merits of AC vs DC Locomotives" (November 2008), http://www.slideshare.net/RailwaysandHarbours/merits-of-ac-vs-dc-locomotives-presentation.

# Figure and table sources for IF3

**Links current as of April 2014**

**Table IF3-1. Class 1 Railroad diesel fuel consumption, fuel cost, and fuel cost share of operating expense, 2012:** U.S. Department of Transportation, Surface Transportation Board, "Annual Report Financial Data," http://www.stb.dot.gov/econdata.nsf/103952f076ac0f8a852566f0006970c9?OpenView.

**Figure IF3-1. Comparison of spot prices for Brent crude oil and Henry Hub natural gas, 1990-2040: History:** U.S. Energy Information Administration, *Monthly Energy Review September 2013*, DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

**Figure IF3-2. Comparison of prices for railroad diesel fuel and liquefied natural gas fuel, 2014-40:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

**Figure IF3-3. Discounted fuel cost savings for a new locomotive and tender using liquefied natural gas as a fuel compared to diesel, 2020-40:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

**Figure IF3-4. Net present value calculation for locomotives using liquefied natural gas at Reference case fuel prices:** AEO2014 National Energy Modeling System, run REF2014.D102413A.

**Figure IF3-5. Discounted fuel cost savings for a new locomotive and tender using liquefied natural gas as a fuel compared to diesel in three cases, 2020-40: Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWPRICE.D120613A, and HIGHPRICE.D120613A.

**Figure IF3-6. Comparison of energy consumption for freight rail using diesel and LNG in three cases, 2015-40: Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, RLNGLOW20.D012914C, and RLNGHIGH20.D012914C.

## IF4. Light-duty vehicle energy demand: demographics and travel behavior

In 2012, energy consumption by light-duty vehicles (LDVs) accounted for 61% of all transportation energy consumption in the United States, or 8.4 million barrels of oil equivalent per day, and represented nearly 10% of world petroleum liquids consumption. LDV energy use is driven by both LDV fuel economy and travel behavior, as measured by LDV vehicle miles traveled (VMT). LDV VMT per licensed driver peaked in 2007 at 12,900 miles per year and decreased to 12, 500 miles in 2012.

The shift in VMT highlights the importance of travel behavior and its influence on LDV energy consumption. Before the 2007 peak, travel behavior in the United States tracked closely with economic growth. Since 2007, trends in U.S. LDV travel have not followed the trends in economic indicators such as income and employment as closely (Figure IF4-1). Although economic factors continue to influence travel demand, demographic, technological, social, and environmental factors also have shown the potential to affect LDV travel.

The AEO2014 Low and High VMT cases examine variations in travel demand as compared with the Reference case. In the Reference case, VMT per licensed driver begin to increase after 2018. The compound annual rate of growth in total VMT for LDVs from 2012 to 2040 in the AEO2014 Reference case is 0.9%—below the 1.7% rate from 1995 to 2005 but higher than the 0.7% average annual growth rate from 2005 through 2012. The Low VMT case assumes an environment in which travel choices made by drivers result in lower demand for personal vehicle travel, consistent with recent trends in VMT per licensed driver. In the Low VMT case, total U.S. LDV travel demand in 2040 is 19% lower than in the Reference case with annual increase in total LDV VMT from 2012 through 2040 averaging 0.2%. The High VMT case assumes changes in travel behavior that result in an increase in VMT per licensed driver compared with the Reference case. In the High VMT case, total U.S. LDV travel demand in 2040 is nearly 6% higher than in the Reference case with annual increase in total LDV VMT from 2012 through 2040 averaging 1.1% (Figure IF4-2).

The alternative VMT cases have direct implications for both projected energy use by LDVs and associated carbon dioxide emissions. In the Low VMT case, U.S. LDVs consume 5.3 million barrels of oil equivalent per day in 2040, 18% less than in the Reference case, resulting in total transportation sector $CO_2$ emissions roughly 9% lower than in the Reference case. In the High VMT case, LDVs consume 6.7 million barrels of oil equivalent per day in 2040, or 5% more than in the Reference case, resulting in total transportation sector $CO_2$ emissions more than 2% higher than in the Reference case (Figures IF4-3 and IF4-4).

### Influential travel demand factors

Fuel use by LDVs is directly related to travel demand, which in turn depends on economic, demographic, technological, social, and environmental factors. In general, the demand for LDV travel is likely to decline when licensing rates fall [1], use of telework increases, or fuel prices are relatively high. Fuel use by LDVs is likely to rise when the driving-age population grows, during periods of expanding economic activity, or when fuel prices are relatively low.

#### Economic factors

Although recent U.S. travel indicators have started to decouple from economic indicators, economic indicators still are a dominant influence on levels of personal travel. There are strong links between economic activity and employment and commuting. Employment rates (Figure IF4-5) largely determine the ability of individuals to travel. When people are not employed and have less income, their daily travel is likely to be much lower than when they are commuting to and from work.

The labor force participation rate, defined as the percentage of the total population ages 16 years and older that is employed or looking for work, has declined since the early 2000s [2]. Reasons for the decline include increasing retirements and lack of

Figure IF4-1. Economic indicators of travel, 1975-2012 (index, 1995 = 1.0)

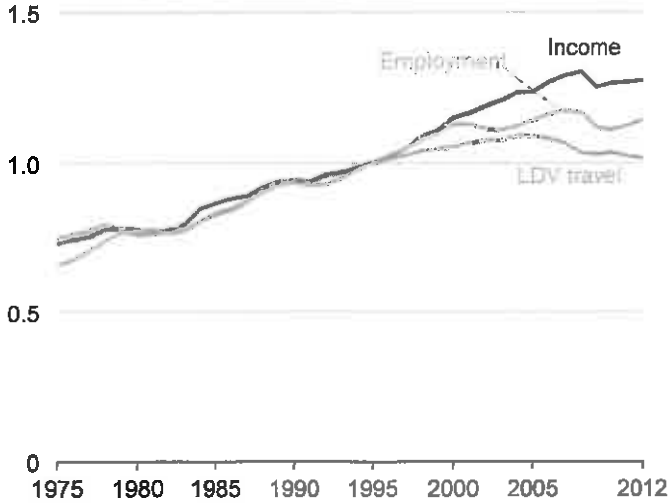
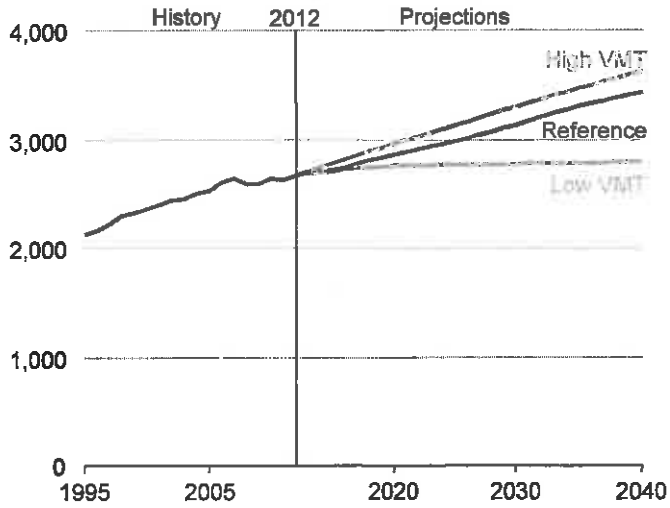



Figure IF4-2. Total light-duty vehicle miles traveled in three cases, 1995-2040 (billion miles)

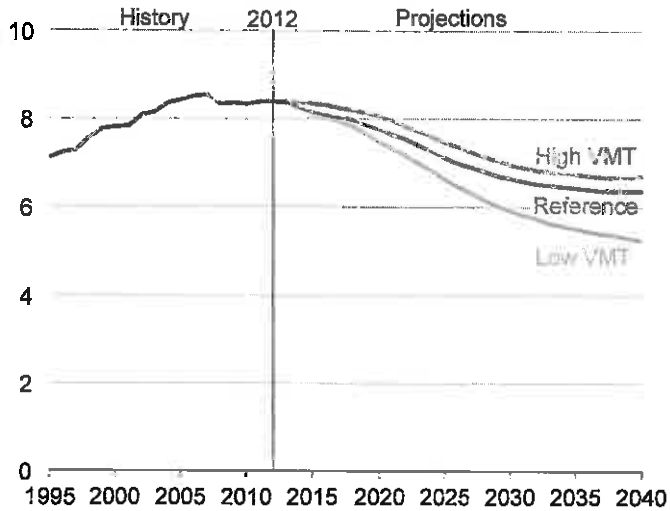


opportunities in the job market (which cause those without jobs to give up on job searches). When the labor force participation rate declines, the unemployment rate may also decline as people are removed from the labor pool, even if overall employment is stable. If the trend continues, retirees and people having difficulty finding jobs may reduce their travel as compared with people who have similar demographic profiles and are employed. When labor force participation rates rise, VMT per driver is likely to increase, particularly for miliennials (those born between the early 1980s and early 2000s).

Other macroeconomic factors also influence travel behavior. Income, fuel prices, the costs of purchasing a vehicle, and other vehicle operating costs all influence the extent to which an individual can afford LDV travel. Households with vehicle ownership rates that equal or exceed the number of licensed drivers in the household have maximum non-overlapping access to vehicles. More recently, a business model that provides drivers with access to a shared-pool of vehicles has developed, particularly in urban areas. Because users of shared pool vehicles incur charges for time of use as well as fuel, this model discourages vehicle use for low-value trips. Income provides the financial means to own and operate a vehicle and, therefore, to travel; but operating costs can affect vehicle utilization rates. When fuel prices increase, the cost of driving increases, and many licensed drivers may choose to drive fewer miles, particularly if their personal incomes do not increase at the same rate as fuel prices.

Economic growth and higher employment rates are correlated with increased travel; however, it is unclear to what extent those economic effects may be offset or reinforced by other factors, such as aging of the population, driver licensing rates, telecommuting rates, and access to alternative travel options. The AEO2014 High and Low VMT cases illustrate potential impacts on overall VMT under plausible combinations of factors that could raise or lower VMT.

Figure IF4-3. U.S. light-duty vehicle energy use in three cases, 1995-2040 (million barrels of oil equivalent per day)




## Demographic factors

Although economic factors play a significant role, demographic factors such as population, age distribution, and licensing rates also are important determinants of LDV travel demand. Population age groups have different gender distributions, licensing rates, and travel behaviors. As the age groups change over time, long-term effects on VMT will become apparent, particularly for the age groups that have the greatest influence on VMT.

A key factor in the recent shift of personal travel demand is specific travel behavior in age and gender groups. In this analysis, the driving population is divided into five age groups (Table IF4-1), and each age group is further divided into males and females (not shown in the table). Licensing rates differ across age and gender groups. Since 1990, licensing rates generally have been declining for the two youngest age groups and increasing for the two oldest groups (Figure IF4-6). For males, most age groups have seen declining or stagnant

Figure IF4-4. U.S. carbon dioxide emissions in the transportation sector in three cases, 1995-2040 (million metric tons)

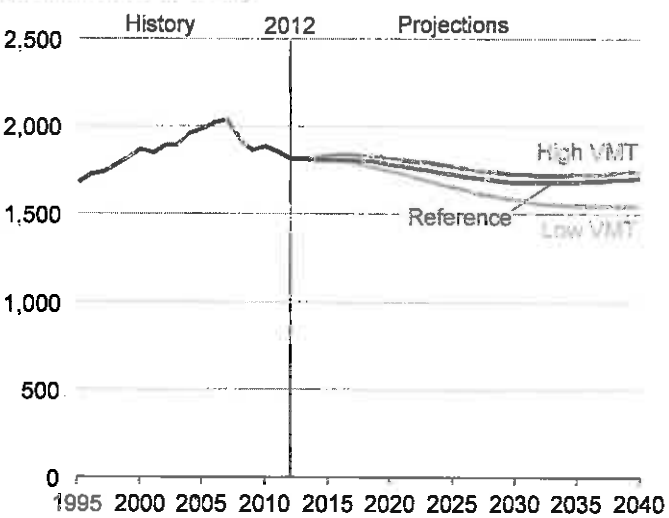
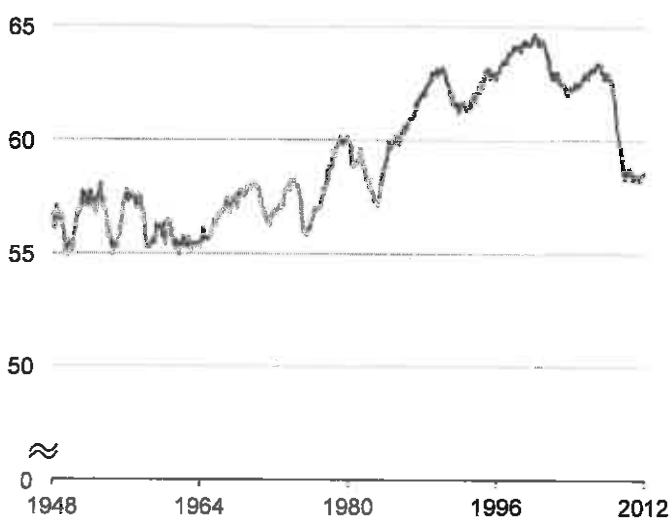



Figure IF4-5. Ratio of U.S. civilian employment to population, 1948-2012 (percent)



licensing rates, with the only exception being males 65 years and older. The female age groups have seen similar stagnation for most of the younger age groups and an increase for females 65 years and older.

Since about 1990, the average age of males who are licensed drivers has been higher than the average age of the male population 16 years and older (the male driving population). That trend is projected to continue as fewer young males obtain licenses or delay obtaining licenses until later in life. Conversely, the average age of female licensed drivers has been lower than the average age of the female driving population, but it is projected to be higher than the average age before 2020 and to continue rising through 2040 (Figure IF4-7). For both males and females, the average age of the driving population and average age of licensed drivers increase in the Reference case, with fewer younger individuals obtaining licenses and more choosing to wait until later in life to become licensed drivers.

The population age 34 years and below has seen a decrease in both licensing rates and VMT per licensed driver, with the licensing rate for the group falling by 5% over the past decade [3]. Some of the decline is a result of increased state restrictions on licenses. For example, for individuals under 18, states almost universally issue provisional licenses with restrictions on driving hours and passengers and do not allow full driving privileges until 18 years of age [4]. Since 2000, VMT per licensed driver for the population under 20 has dropped by 13%. In 1990, 52% of eligible individuals under 20, and 92% of those between 20 and 34 years of age, obtained their licenses. In 2010, those shares were 43% and 86%, respectively [5]. If the trend persists, licensing rates could continue to decline or flatten out for the youngest driving populations, further reducing VMT per capita. If the licensing rate returns to historic levels, total VMT will increase. Technological factors may also play a role for younger age groups, as discussed below.

The peak driving age group, between 35 and 54 years of age, has experienced a small decline in licensing, from 95% in 1990 to an estimated 92% in 2010. Drivers in this age group traveled an average of almost 15,000 miles annually in 2012, the highest rate of VMT per licensed driver for any age group. This relatively large age group, accounting for 34% of the population in 2012, has a limited influence on changes in total VMT, because neither the licensing rate nor the share of the population has changed drastically through history or is projected to change significantly in the future. Much of that stability results from high employment rates for this age group, as a result of the interaction between economic and demographic factors.

The overall population share in the oldest age group, 65 years and older, has grown steadily since 2000 and is expected to reach 24% of the total population ages 16 and above in 2025, up from a 17% share in 2012. Although the size of this segment of the population has grown since 2000, personal travel (VMT per capita) by the oldest age group dropped by 7% between 2008 and 2009, and its total VMT dropped by 10%. More members of the older population are obtaining their licenses than in the past, but they also have altered their travel behavior, increasing their use of public transportation by 40% during the period from 2001 to 2009 [6]. As the aging of the U.S. population continues, long-term effects on VMT will be apparent, particularly as seen in older driver behavior versus younger driver behavior, as well as gender and regional differences in driver behavior.

Table IF4-1. Historic and projected distribution of age groups

| | Percent of population ages 16 and above | | |
|---|---|---|---|
| Age (years) | 2012 | 2025 | 2040 |
| 16-19 | 6.9 | 6.1 | 6.0 |
| 20-34 | 26.1 | 24.4 | 22.8 |
| 35-54 | 34.1 | 30.9 | 30.9 |
| 55-64 | 15.5 | 15.0 | 13.5 |
| 65+ | 17.4 | 23.7 | 26.8 |

Figure IF4-6. Driver licensing rates by age group, 1990-2010 (percent of total age group)

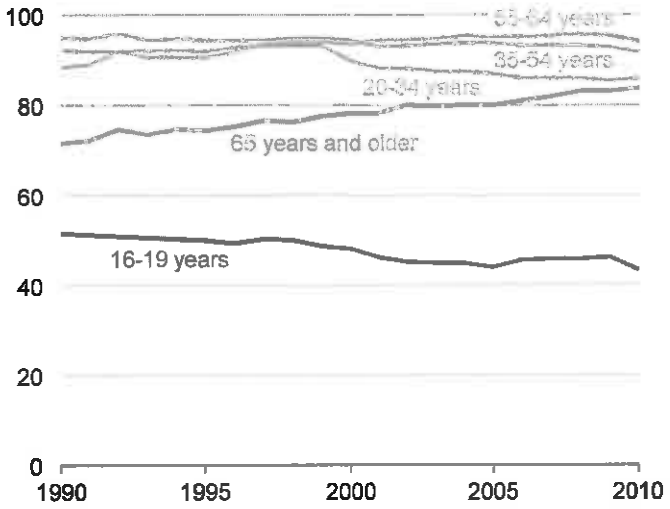
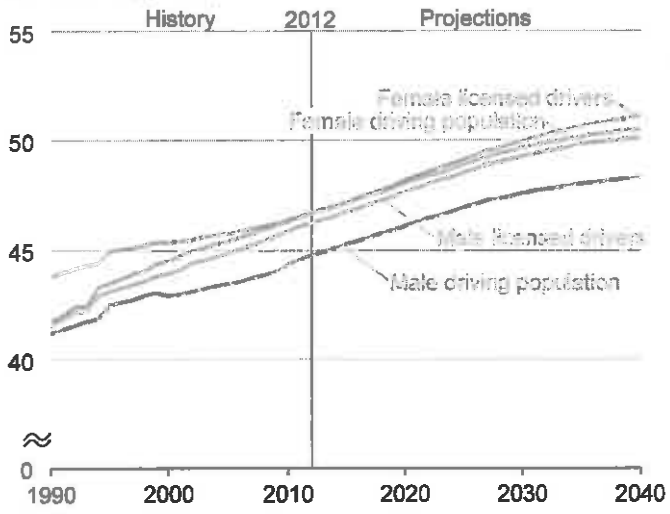



Figure IF4-7. Average ages of male and female driving-age populations and licensed drivers, 1990-2040 (years)



Demographic changes can also interact with other factors to influence VMT. Historically, shifts in demographics coupled with economic changes have had major impacts on total travel. For example, the increasing number of women who entered the work force beginning in the 1970s—and added secondary incomes for their families—led to a rise in VMT that combined both economic activity and demographic changes. In the future, factors that influence VMT may merge in various ways that change long-term trends in U.S. travel demand.

### Technological, social, and environmental factors

Technological, social, and environmental factors also can influence VMT. Alternative modes of travel affect VMT to the degree that the population has access to substitutes for personal LDVs. The decision to choose a substitute travel option depends on cost in comparison to personal LDVs, convenience, personal preferences, and the availability of mass transit, rail, biking, and pedestrian travel service options. Other opportunities may also affect personal travel, including car-sharing services, car rental and taxi services, and carpooling.

Technological changes and improvements can also affect VMT. The increasing fuel efficiency of LDVs can influence personal travel by lowering the marginal cost of driving per mile. As vehicle efficiency improves, individuals can drive the same distance with less fuel and therefore at a lower cost, which may result in an increase in VMT. In recent analyses supporting the promulgation of new final fuel economy and greenhouse gas emissions standards for LDVs in model years 2017 through 2025, the National Highway Traffic Safety Administration (NHTSA) and the U.S. Environmental Protection Agency (EPA) applied a 10% rebound in VMT to reflect the lower fueling costs of more efficient vehicles [7].

Other types of technological and environmental changes also can affect personal travel. Telecommuting, e-commerce, urbanization, and social media can supplant or complement personal vehicle use. Telecommuting, or working from home, can influence personal VMT. From 1997 to 2010, the share of the workforce working at least one day of the week from home increased from 7% to 9.5%. As that trend grows, so does the likelihood that individuals will reduce their total miles driven. The share of the working population that works exclusively from home also has increased, from 4.8% in 1997 to 6.6% in 2010 [8]. Although telecommuting can have an impact on reducing VMT, work-related travel in 2009 was only 25% of total personal travel [9].

Technological advances have increased access to and the availability of electronic devices and other opportunities that can influence VMT—including, but not limited to, social media, GPS applications, and electronic devices. Some analysts have suggested an association between rising interest in social media and a decline in the rates at which driving-age youth obtain driver licenses. Others suggest that access to social media actually increases opportunity and desire for travel. Mobile technology and changing preferences of the younger generations will play a significant part in determining the future of LDV travel.

Finally, spatial development patterns may begin to play a different role in determining VMT than is suggested by history, as suburban sprawl gives way to other development patterns. Urbanization generally results in increases in, and greater access to, public transportation and would be likely to support other forms of transportation, including biking, car sharing, and carpooling. Land use changes and related policies, mainly at the local level but supported or incentivized by state and federal policies, have had only localized impacts on VMT to date. However, the tradeoff between suburban and exurban development and urban infill development is likely to change over the coming decades, and those changes could affect VMT.

Figure IF4-8. Vehicle use by drivers 16-19 years old in three cases, 1990-2040 (VMT per licensed driver per year)

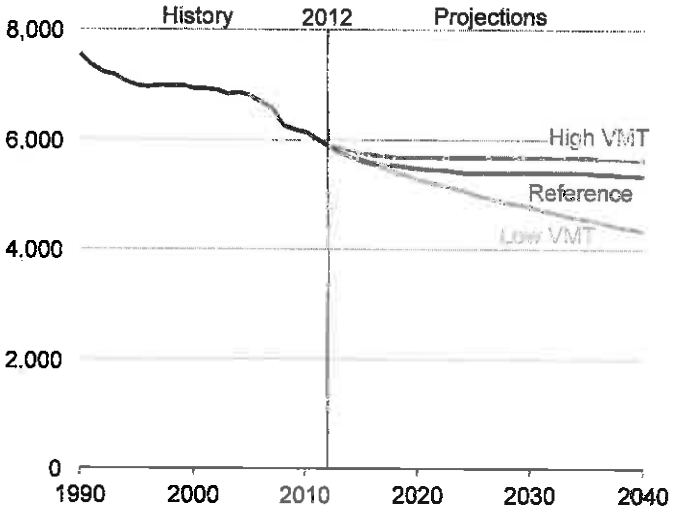
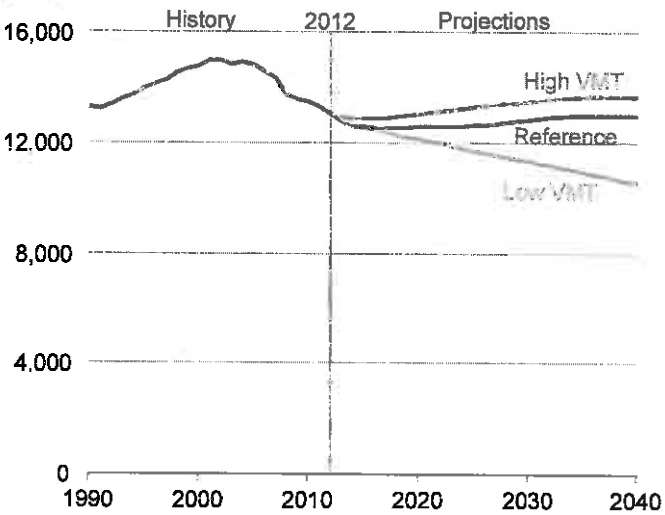



Figure IF4-9. Vehicle use by drivers 20-34 years old in three cases, 1990-2040 (VMT per licensed driver per year)



## VMT sensitivity analysis

The High and Low VMT cases suggest possible future changes in travel behavior and their potential impacts on VMT and on LDV energy demand. The Low VMT case assumes a 0.5% annual decrease in VMT per licensed driver from 2013 to 2040 for each age and gender group. The High VMT case assumes a pattern of annual increases in VMT per licensed driver: 0.3% starting in 2013, 0.4% starting in 2016, 0.5% starting in 2019, and 0.6% starting in 2023, slowing to 0.5% starting in 2027, 0.4% starting in 2032, and 0.3% from 2036 through 2040. Figures IF4-8 through IF4-12 show VMT per licensed driver in each case for five age groups.

In the Low VMT case, VMT per licensed driver for all drivers decline throughout the projection, to about 10,400 miles per year in 2040—a 19% decrease from 12,800 miles per year in 2040 in the Reference case. In the High VMT case, VMT per licensed driver for all drivers rise to 13,500 miles per year in 2040—nearly 6% higher than in the Reference case (Figure IF4-13). In the Low VMT case, VMT per licensed driver across all age groups decline by an average of 0.7% per year from 2012 to 2040, compared with an average increase of 0.1% per year in the Reference case. The High VMT case projects 0.3% average annual growth in VMT per licensed driver from 2012 through 2040.

Total LDV VMT increase only slightly in the Low VMT case, to almost 2.8 trillion miles in 2040, as compared with 3.6 trillion miles in 2040 in the High VMT case. Annual increases in total LDV VMT from 2012 to 2040 average 0.2% in the Low VMT case and 1.1% in the High VMT case.

Figure IF4-10. Vehicle use by drivers 35-54 years old in three cases, 1990-2040 (VMT per licensed driver per year)

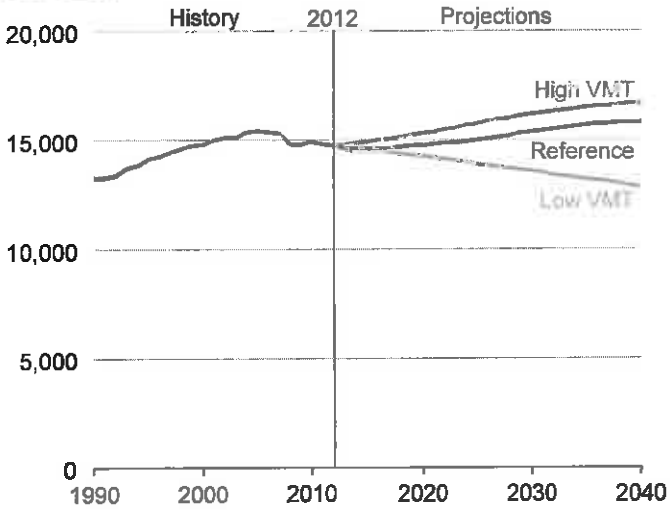



Figure IF4-11. Vehicle use by drivers 55-64 years old in three cases, 1990-2040 (VMT per licensed driver per year)

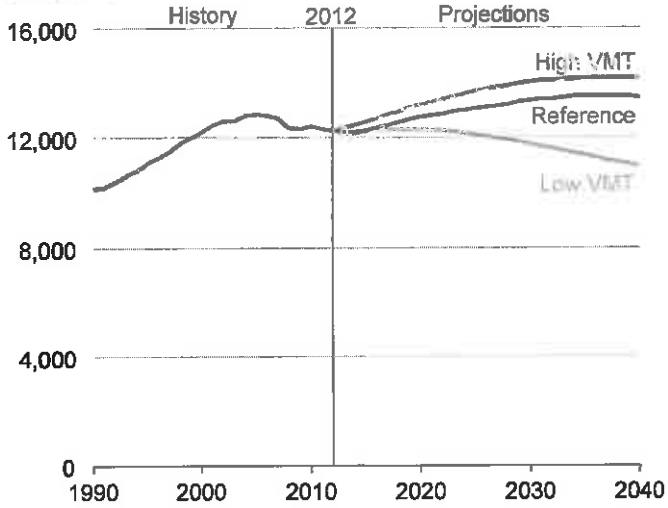



Figure IF4-12. Vehicle use by drivers 65+ years old in three cases, 1990-2040 (VMT per licensed driver per year)

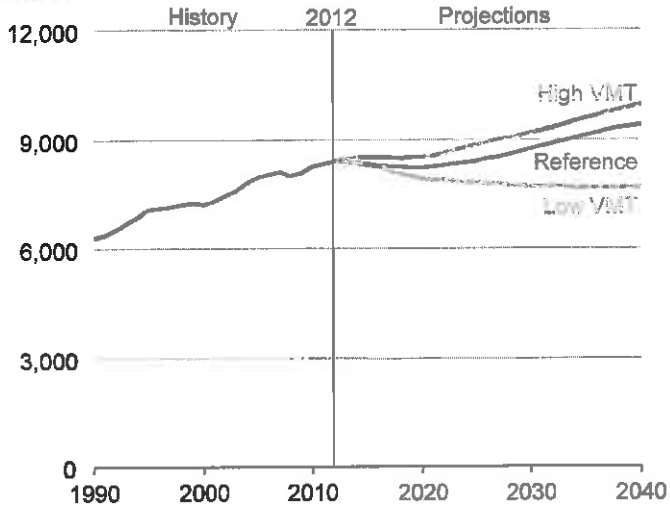
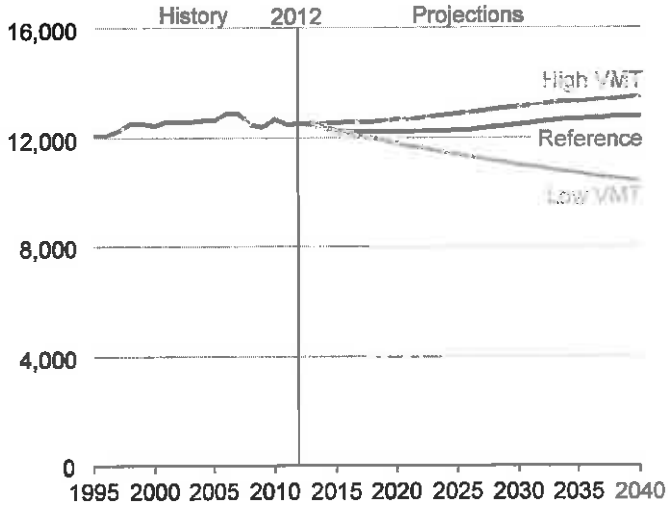



Figure IF4-13. Vehicle use by all drivers in three cases, 1995-2040 (VMT per licensed driver per year)



# Endnotes for IF4

**Links current as of April 2014**


1. The licensing rate is the share of a population or group 16 years old or older that have driver's licenses.
2. U.S. Department of Labor, Bureau of Labor Statistics, "Labor Force Participation Rate," http://data.bls.gov/timeseries/LNS11300000.
3. United States Public Interest Research Group (PIRG) Education Fund and Frontier Group, *Transportation and the New Generation* (April 2012), http://www.uspirg.org/reports/usp/transportation-and-new-generation.
4. Government Highway Safety Association, "Graduated Driver Licensing Laws" (March 2014), http://www.ghsa.org/html/stateinfo/laws/license_laws.html.
5. U.S. Department of Transportation, Federal Highway Administration, Highway Statistics Series (2012), https://www.fhwa.dot.gov/policyinformation/statistics.cfm.
6. J. Lynott and C. Figueiredo, "Fact Sheet 218: How the Travel Patterns of Older Adults Are Changing: Highlights from the 2009 National Household Travel Survey" (AARP Public Policy Institute, April 2011), http://assets.aarp.org/rgcontent/npi/ppi-com/fs218-transportation.pdf.
7. 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/2012/10/15/2012-25623/2017-and-later-model-year-light-duty-vehicle-greenhouse-gas-emissions-and-corporate-average-fuel.
8. P.J. Mateyka, M.A. Rapino, and L.C. Landivar, *Home-Based Workers in the United States: 2010* (U.S. Department of Commerce, U.S. Census Bureau, Washington, DC, October 2012), http://www.census.gov/prod/2012pubs/p70-132.pdf.
9. U.S. Department of Transportation, Federal Highway Administration, "2009 NHTS - Version 2.1" (February 2011), http://nhts.ornl.gov/download.shtml.

# Figure and table sources for IF4

**Links current as of April 2014**

**Figure IF4-1. Economic indicators of travel, 1975-2012: Income:** U.S. Bureau of Economic Analysis, "GDP and Personal Income" *National Data*, http://www.bea.gov/iTables/index_nipa.cfm. **Employment:** U.S. Department of Labor, Bureau of Labor Statistics, *Current Employment Statistics*, http://www.bls.gov/ces/#data. **LDV Travel:** U.S. Department of Transportation, Federal Highway Administration, "Table VM-1," Highway Statistics Series 2011 (March 2013), https://www.fhwa.dot.gov/policyinformation/statistics/2011/.

**Figure IF4-2. Total light-duty vehicle miles traveled in three cases, 1995-2040: History:** U.S. Department of Transportation, Federal Highway Administration, "Table VM-1," *Highway Statistics Series 2011* (March 2013), https://www.fhwa.dot.gov/policyinformation/statistics/2011/. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

**Figure IF4-3. U.S. light-duty vehicle energy use in three cases, 1995-2040: History:** U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey*, http://nhts.ornl.gov/download.shtml. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

**Figure IF4-4. U.S. carbon dioxide emissions in the transportation sector in three cases, 1995-2040: History:** S.C. Davis, S.W. Diegel, and R.G. Boundy, *Transportation Energy Data Book*, Edition 31 (July 2012), http://info.ornl.gov/sites/publications/files/Pub37220.pdf. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

**Figure IF4-5. Ratio of U.S. civilian employment to population, 1948-2012:** U.S. Department of Labor, Bureau of Labor Statistics, Current Employment Statistics, http://www.bls.gov/ces/#data.

**Table IF4-1. Historic and projected distribution of age groups:** U.S. Department of Commerce, U.S. Census Bureau, 2010 Census Data, https://www.census.gov/2010census/data/.

**Figure IF4-6. Driver licensing rates by age group, 1990-2010:** U.S. Department of Transportation, Federal Highway Administration, "Table DL-22," *Highway Statistics Series 2011* (March 2013), https://www.fhwa.dot.gov/policyinformation/statistics/2011/.

**Figure IF4-7. Average ages of male and female driving-age populations and licensed drivers, 1990-2040: History:** U.S. Department of Transportation, Federal Highway Administration, "Table DL-22," *Highway Statistics Series 2011* (March 2013), https://www.fhwa.dot.gov/policyinformation/statistics/2011/; and U.S. Department of Commerce, U.S. Census Bureau, *2010 Census Data*, https://www.census.gov/2010census/data/. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

**Figure IF4-8. Vehicle use by drivers 16-19 years old in three cases, 1990-2040: History:** U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey*, http://nhts.ornl.gov/download.shtml. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

**Figure IF4-9. Vehicle use by drivers 20-34 years old in three cases, 1990-2040: History:** U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey*, http://nhts.ornl.gov/download.shtml. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

**Figure IF4-10. Vehicle use by drivers 35-54 years old in three cases, 1990-2040: History:** U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey*, http://nhts.ornl.gov/download.shtml. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

**Figure IF4-11. Vehicle use by drivers 55-64 years old in three cases, 1990-2040: History:** U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey*, http://nhts.ornl.gov/download.shtml. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

**Figure IF4-12. Vehicle use by drivers 65+ years old in three cases, 1990-2040: History:** U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey*, http://nhts.ornl.gov/download.shtml. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

**Figure IF4-13. Vehicle use by all drivers in three cases, 1995-2040: History:** U.S. Department of Transportation, Federal Highway Administration, *National Household Travel Survey*, http://nhts.ornl.gov/download.shtml. **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWVMT.D020314B, and HIGHVMT.D020314D.

### IF5. Effects of lower natural gas prices on projected industrial production

This analysis focuses on variation in industrial output in the Low and High Oil Price cases and Low and High Oil and Gas Resource cases compared to the *Annual Energy Outlook 2014* (AEO2014) Reference case. Energy-intensive industries, including food, paper, bulk chemicals, glass, cement, iron and steel, and aluminum, are the industries that use the largest amount of energy per unit of output and are the most sensitive to natural gas prices. Of these, the most natural gas-intensive industries are food, paper, bulk chemicals, and glass [1].

Analysis of the industrial sector as a whole reveals strong links between natural gas prices and industrial production [2]. Further analyses reveal important data issues and indicate some basic sensitivity to natural gas prices for the most energy-intensive industries, subject to trade competition, when they are disaggregated [3, 4]. Those studies show evidence of a straightforward production decline when natural gas prices to the bulk chemicals industry increase, but the relationship does not appear to apply to the less natural gas-intensive cement industry. The same studies point to an important role for demand, both foreign and domestic, for all industries, including the energy-intensive industries. The National Energy Modeling System used to produce AEO2014 includes sufficient disaggregation to support analysis of the influence of natural gas prices on industrial output.

### Demand categories

Expenditure categories, such as personal consumption, investment, government spending, and trade, measure underlying demand in the U.S. economy. Each category includes more detailed disaggregation, such as durable and nondurable goods. The AEO2014 industrial output projections use 59 different categories of final demand, with the effects of each category on industrial production differing across industries. The most important final demand categories for the industries analyzed here, according to input-output tables from the Commerce Department's Bureau of Economic Analysis (BEA) [5], are consumer spending, trade, and investment (see box below). In addition to demand from domestic consumers and trade, interindustry demand also affects the industrial sector.

#### Impact of Bureau of Economic Analysis revisions on the National Income and Product Accounts

BEA performs comprehensive National Income and Product Accounts (NIPA) revisions approximately every five years. The 2013 release was its 14th comprehensive revision. The previous release was in July 2009. The BEA comprehensive revisions incorporate changes in the methods used to measure the U.S. economy as well as the most up-to-date, most complete, and most accurate source data available. Changes in NIPA definitions, classifications, and presentations as a result of the 2013 comprehensive revision include:

- Capitalization of expenditures on research and development (R&D)
- Capitalization of expenditures on entertainment, literary, and artistic originals
- Addition of intellectual property products to the fixed investment tables, including R&D; entertainment, literary, and artistic originals; and software
- Accrual treatment of defined benefit pension plan transactions, recognizing the costs of unfunded liabilities
- Expanded set of ownership transfer costs for residential fixed assets
- Change of the reference year for price indexes and inflation-adjusted series.

The AEO2014 Reference case and High and Low Economic Growth cases started with the IHS Global Insight U.S. long-term model simulations available in March and June 2013, which do not reflect the latest comprehensive NIPA revisions for two reasons. First, the July 2013 NIPA revisions were issued late in the AEO preparation cycle. The late issuance of the NIPA revisions delayed the September and October releases of the IHS Global Insight U.S. long-term model simulations, normally used in preparation of the U.S. Energy Information Administration's (EIA) *Annual Energy Outlook* (AEO). Second, EIA uses the economic forecast together with interindustry data describing how each industry uses other industries' output, and how each industry satisfies its final demand components [6]. BEA released the updated interindustry tables in December 2013, much too late for the AEO. While the comprehensive NIPA revisions affect past and projected estimates of GDP, they are not expected to materially affect projected energy use. The results of the 2013 NIPA comprehensive revisions will be included in EIA's *Annual Energy Outlook 2015*.

Although the 2013 comprehensive NIPA revision did not lead to changes in broad economic trends or in the general patterns of past business cycles, it did increase gross domestic product (GDP) in every year back to 1929. The average annual growth rate of real GDP from 1929 to 2012 was revised upward to 3.3%, as compared with the previous estimate of 3.2%. More recently, the annual growth rate from 2002 to 2012 was revised upward to 1.8%, as compared with the previous estimate of 1.6%. The economic recession of 2007-09 (December 2007 to June 2009) now looks less severe than previously reported—with GDP contracting by 2.9% over that period after the comprehensive revision, compared with 3.2% before the revision. In addition, the current recovery is stronger than first reported—a 2.2% average annual expansion from the second quarter of 2009 through the first quarter of 2013, compared with 2.1% before the revision. The revised data also indicate that the economy shrank at an average annual rate of 1.3% in the first quarter of 2011, compared with 0.1% growth before the revision.

*(continued on next page)*

Changes in 2012 nominal GDP as a result of the comprehensive revision total $559.8 billion, including $526 billion (94%) attributable to changes in definitions and $33.8 billion (6%) resulting from statistical changes. Research and development capitalization accounts for 75% of definitional changes, or $396.7 billion. Two-thirds of R&D expenditures are made by the private sector and one-third by government. The remaining changes to definitions include capitalization of entertainment, literary, and artistic originals ($74.3 billion, or 14%); an expanded set of ownership transfer costs for residential fixed assets ($42.3 billion, or 8%); and accrual accounting for defined benefit pension programs ($12.6 billion, or 2%).

Figure IF5-1. Bureau of Economic Analysis revisions to gross domestic product by major component, 2002-12 (billion dollars)

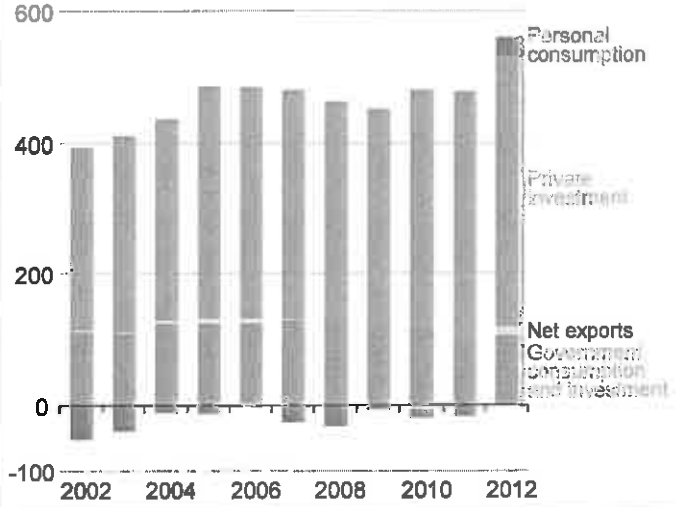



Figure IF5-1 shows the annual impacts of the NIPA revisions on the major components of GDP from 2002 to 2012. Private investment and government expenditures accounted for 92% of the $560 billion upward revision in 2012, primarily as a result of the capitalization of R&D expenditures. Revisions to gross private domestic investment contributed $413 billion, or 74% of the total; revisions to government expenditures contributed $104 billion, or 19% of the total; and revisions to personal consumption and net exports contributed $43 billion, or 7% of the total upward revision to 2012 GDP.

The increase in private and government investment spending is primarily the result of BEA's continued work to broaden the definition of GDP. With this comprehensive revision, NIPA now includes capitalization of spending on R&D and on long-lived artwork produced by artists, studios, and publishers—intangible assets that previously were considered intermediate inputs to the production of other goods or services. Although the inclusion of intangible assets does raise the measured level of overall economic activity, it has only a modest impact on economic growth rates.

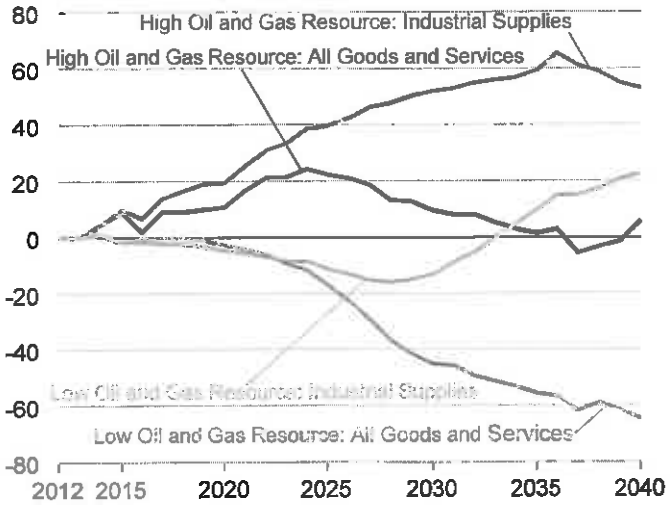
## Alternative cases

### Results

#### Oil and Gas Resource cases

Changes in the assumed size of the U.S. oil and natural gas resource base and the rate of technology advance within the sector can affect the nation's economy. In general, increases in oil and natural gas resources result in lower prices and higher industrial output, and a smaller oil and natural gas resource base results in higher prices and lower industrial output. However, the cases are not symmetric. In the High Oil and Gas Resource case, GDP is 1.2% higher in 2040 than projected in the Reference case, total industrial output is 5.1% higher in 2040, and bulk chemicals and paper industries output is 11.5% higher in 2040, as a result of improved trade advantages resulting from lower prices. The changes tend to be smaller in the Low Oil and Gas Resource case. GDP is 0.4% lower in 2040 than projected in the Reference case, total industrial output is 2.3% lower in 2040, and bulk chemicals and paper industries output is 5.0% lower in 2040, as a result of lower oil and natural gas production and higher prices in the Low Oil and Gas Resource case.

Figure IF5-2. Changes from the Reference case in annual net exports, Low and High Oil and Gas Resource cases, 2012-40 (billion 2005 dollars)




Among the final demand categories, trade of industrial supplies (Figure IF5-2) and consumer goods (Figure IF5-3) show the largest differences across the Oil and Gas Resource cases. Energy trade is a major component of industrial supplies. Trade of industrial supplies and consumer goods drives production in the bulk chemicals industry (Figure IF5-4). The price advantage of natural gas-based feedstock varies widely in the High Oil and Gas Resource case (Figure IF5-5), with corresponding impacts on the bulk chemicals industry. Differences in production of bulk chemicals account for a large portion of the differences in fuel consumption results, particularly for petroleum and other liquids and for natural gas, both of which are used as feedstocks in the bulk chemicals industry.

In the High Oil and Gas Resource case, exports of all goods and services from 2012 to 2025 grow faster than imports, as a result of lower U.S. producer prices [7] that are attributable in part to lower natural gas prices (see Figure IF5-2). After 2025, the growth rate of imports begins to increase. Net exports of industrial supplies continue to grow throughout the projection in the High Oil and Gas Resource case, because energy imports are low. In the Low Oil and Gas Resource case, net exports of all goods and services decline through 2040, primarily as a result of slow export growth when U.S. producer prices are higher than those in the Reference case. Net exports of industrial supplies in the Low Oil and Gas Resource case are lower than in the Reference case until 2034, when nonenergy imports drop below Reference case levels as U.S. producer price inflation slows.

**Oil Price cases**

In comparison with the Reference case, the Low Oil Price case shows lower natural gas prices and production, and the High Oil price case shows higher natural gas prices and production. However, the magnitude of the changes in the Oil Price cases is smaller than in the Oil and Gas Resource cases. The changes in natural gas prices in the Low Oil Price case affect the economy earlier in the projection, leading to changes in inflation, unemployment, and interest rates. In the High Oil Price case, the economy shows larger losses beginning earlier than in the Low Oil and Gas Resource case but recovers as natural gas production expands.

In both the Low and High Oil Price cases, the largest changes from the Reference case are for trade in industrial supplies (Figure IF5-6) and consumer goods (Figure IF5-7), which primarily affect the bulk chemicals, glass, and paper industries. Differences

Figure IF5-3. Changes from the Reference case in consumer spending, Low and High Oil and Gas Resource cases, 2012-40 (billion 2005 dollars)

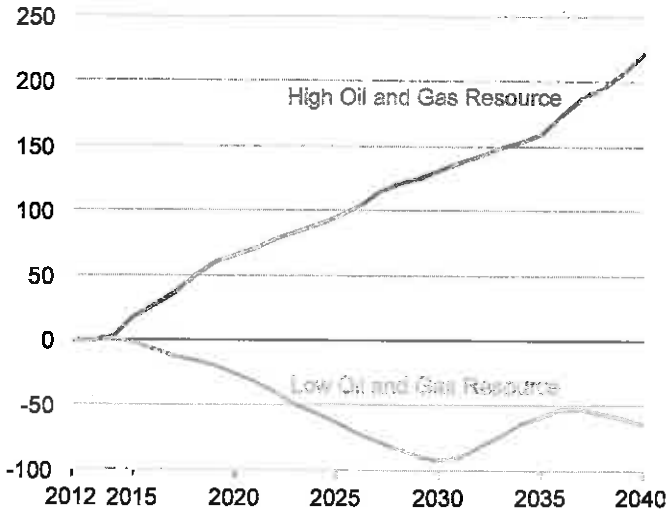



Figure IF5-4. Bulk chemicals value of shipments in three cases, 2012-40 (billion 2005 dollars)

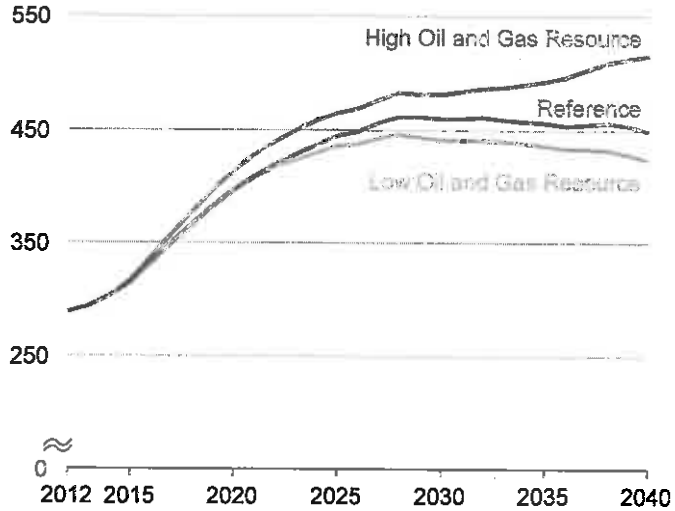



Figure IF5-5. Ratio of ethane to naphtha feedstock prices in three cases, 2012-40

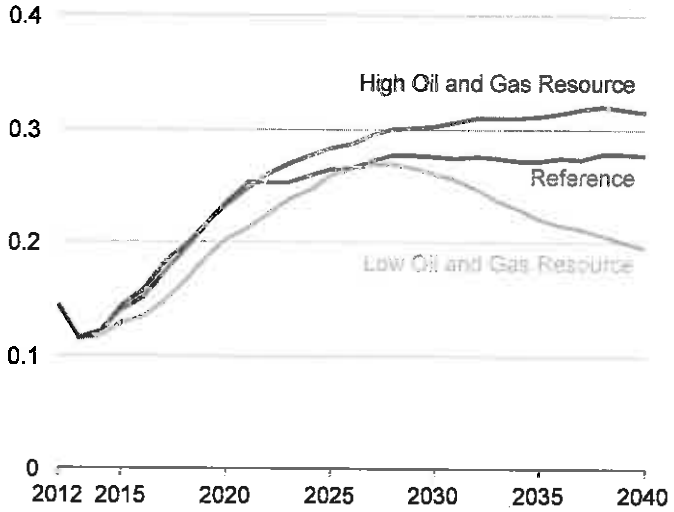



Figure IF5-6. Changes from the Reference case in net exports, Low and High Oil Price cases, 2012-40 (billion 2005 dollars)

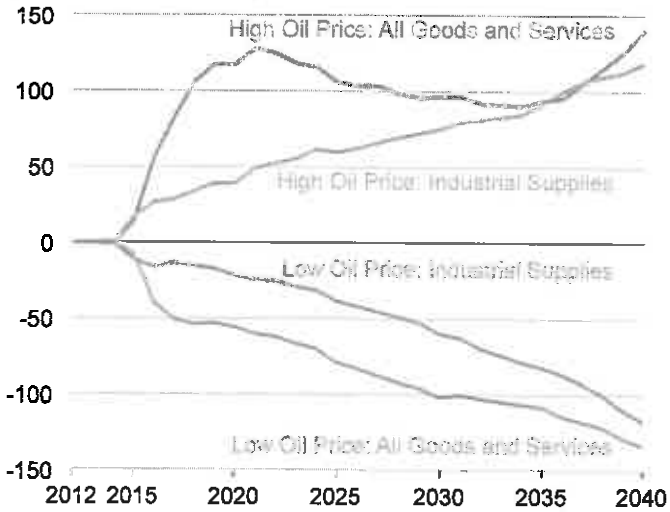
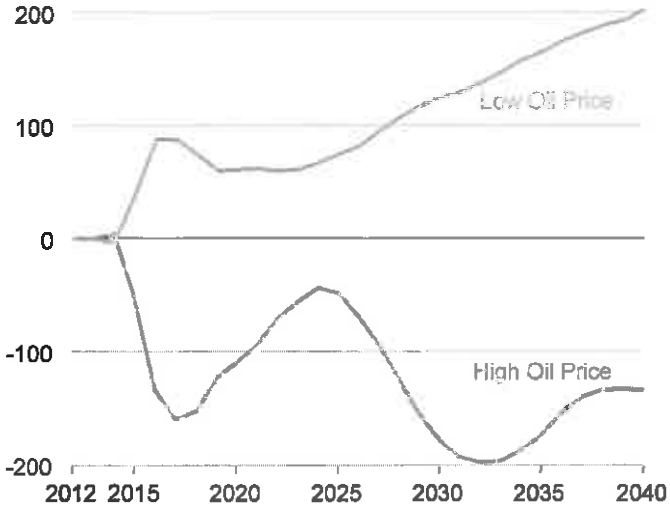


Figure IF5-7. Changes from the Reference case in consumer spending, Low and High Oil Price cases, 2012-40 (billion 2005 dollars)




in consumer spending affect output in the glass and paper industries, which are tightly linked to consumer goods and more closely tied to demand for capital goods than is the bulk chemicals industry. Fuel consumption trends in the Low and High Oil Price cases differ from those in the Low and High Oil and Gas Resource cases, primarily because of the bulk chemicals industry. The initial response of the bulk chemicals industry to higher oil prices compared with the Reference case is a decrease in output (Figure IF5-8), and the initial response to lower oil prices is an increase in output, which does not occur in the High and Low Oil and Gas Resource cases (see Figure IF5-4). In the High Oil Price case, oil prices grow faster than the prices of natural gas-based feedstocks, leading to a price advantage for natural gas feedstocks (Figure IF5-9). As a result, bulk chemicals output in the High Oil Price case in 2040 is higher than in the Reference case. In the Low Oil Price case, with natural gas prices increasing more than oil prices, bulk chemicals output remains below the Reference case level in 2040.

Figure IF5-8. Shipments of bulk chemicals in three cases, 2012-40 (billion 2005 dollars)

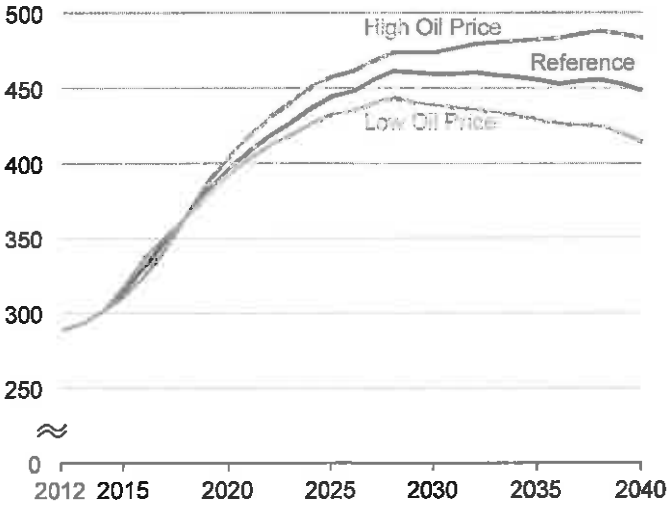
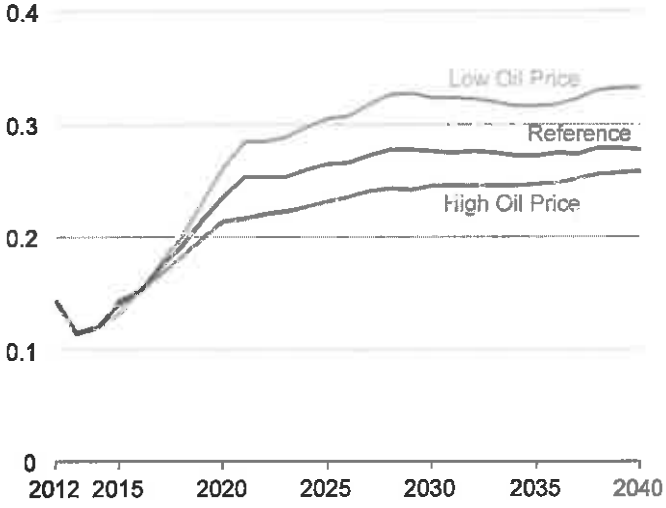



Figure IF5-9. Ratio of ethane to naphtha feedstock prices in three cases, 2012-40



## Endnotes for IF5

**Links current as of April 2014**


1. U.S. Energy Information Administration, 2010 Manufacturing Energy Consumption Survey (MECS). http://www.eia.gov/consumption/manufacturing/index.cfm.
2. V. Arora and J. Lieskovsky, "Natural gas and U.S. economic activity," *The Energy Journal* (forthcoming, 2014).
3. E. Sendich, "The importance of natural gas in the industrial sector with a focus on energy-intensive industries," EIA Discussion Paper (February 28, 2014), http://www.eia.gov/discussionpapers/?page=bookshelf.
4. V. Arora and E. Sendich, "Natural gas and U.S. industrial production: a closer look at four industries" (unpublished).
5. Bureau of Economic Analysis, Industry Accounts, http://bea.gov/industry/index.htm#annual.
6. For a more detailed description of the interindustry data changes, see "Benchmark input-output account of the U.S. economy, 2007" (December 18, 2013), http://www.bea.gov/newsreleases/industry/io/iomakeup.htm.
7. The producer price index, used to capture the selling prices received by domestic producers for their output, represents the price paid by industrial sector purchasers for inputs.


## Figure sources for IF5

**Links current as of April 2014**

**Figure IF5-1. Bureau of Economic Analysis revisions to gross domestic product by major component, 2002-12: History:** U.S. Department of Commerce, Bureau of Economic Analysis, "National Income and Products Account Table," Table 1.1.5, Gross Domestic Product, First Quarter Third Release (Washington, DC, June 26, 2013), http://www.bea.gov/newsreleases/national/gdp/2013/gdp1q13_3rd.htm; and U.S. Department of Commerce, Bureau of Economic Analysis, "National Income and Products Account Table," Table 1.1.5, Gross Domestic Product, Second Quarter Advanced Release (Washington, DC, July 31, 2013), http://www.bea.gov/newsreleases/national/gdp/2013/gdp2q13_adv.htm.

**Figure IF5-2. Changes from the Reference case in annual net exports, Low and High Oil and Gas Resource cases, 2012-40: Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

**Figure IF5-3. Changes from the Reference case in consumer spending, Low and High Oil and Gas Resource cases, 2012-40: Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

**Figure IF5-4. Shipments of bulk chemicals in three cases, 2012-40: Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

**Figure IF5-5. Ratio of ethane to naphtha feedstock prices in three cases, 2012-40: Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

**Figure IF5-6. Changes from the Reference case in net exports, Low and High Oil Price cases, 2012-40: Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

**Figure IF5-7. Changes from the Reference case in consumer spending, Low and High Oil Price cases, 2012-40: Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

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**Figure IF5-9. Ratio of ethane to naphtha feedstock prices in three cases, 2012-40: Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWRESOURCE.D112913A, and HIGHRESOURCE.D112913B.

## IF6. Implications of accelerated power plant retirements

In 2012, coal-fired and nuclear power plants together provided 56% of the electricity generated in the United States. The role of these technologies in the U.S. generation mix has been changing since 2009, as both low natural gas prices and slower growth of electricity demand have altered their competitiveness relative to other fuels. Many coal-fired plants also must comply with requirements of the Mercury and Air Toxics Standards (MATS) and other environmental regulations. Some of the challenges faced by coal-fired and nuclear generators, and the implications for electricity markets if the plants are retired in significant numbers, are analyzed in this discussion.

Of the total installed 310 gigawatts (GW) of coal-fired generating capacity available at the end of 2012, 50 GW, or 16%, is projected to be retired by 2020 in the AEO2014 Reference case. Despite those projected retirements, coal continues to account for the largest share of the electricity generation mix through 2034, after which it is overtaken by natural gas. However, throughout the projection the coal share of total generation remains significantly below its 49% share in 2007, when coal set its annual generation record.

In 2012 and 2013, operators of five nuclear power reactors representing 4.2 GW of capacity announced plans to retire the reactors by 2015. Four of the reactors—San Onofre 2 and 3, Kewaunee, and Crystal River—already have ended nuclear power production, and the fifth, Vermont Yankee, is expected to end generation by the end of 2014 [1]. In addition, the Oyster Creek plant is expected to conclude operation in 2019 [2]. These are the first retirements of U.S. nuclear power plants since Millstone Unit 1 was retired in 1998. Retirements often are the result of unique circumstances, but some owners of nuclear power plants have voiced concerns about the profitability of their units, sparking discussion of possible additional nuclear retirements [3]. In order to evaluate the impacts of potential retirements beyond those in the Reference case, AEO2014 includes several alternative cases with economic assumptions that make it less likely that existing coal and nuclear power plants will be used for generation.

### Factors that lead to power plant retirements

Power plant owners generally make the decision to retire plants when their expected costs exceed their expected revenues over the future life of the plants [4]. Costs incurred by power plants can include large capital projects, such as installation of flue gas desulfurization (FGD) systems or scrubbers on coal plants, increased operating costs, or higher fuel costs. Revenues are received from energy sales or capacity payments in wholesale electricity markets in regions of the country with competitive wholesale markets, or from cost-recovery mechanisms in regions with vertically integrated utilities subject to rate regulations [5].

Recent trends in the electric power industry have resulted in both declining revenues and increased operating costs for coal plants. Because natural gas often is the marginal fuel and thus sets prices in Regional Transmission Organization (RTO) markets, and natural gas influences wholesale electricity prices in non-RTO markets, the decline in natural gas prices beginning in 2008 tends to reduce electricity prices and the payments received by all generators for the electricity they produce. Lower natural gas prices also improve the competitiveness of natural gas combined-cycle (NGCC) power plants relative to coal-fired plants. When lower natural gas prices drive the cost of generating electricity from an NGCC plant below that of a nearby coal-fired plant, the coal plant is dispatched, or operated, less often and earns less revenue [6].

Slow growth of electricity demand in recent years has resulted in fewer high-cost marginal generators being dispatched. In regions with excess generating capacity, plants with relatively high variable operating costs may not be dispatched frequently enough to produce the revenue needed to cover their costs [7], making them candidates for retirement. Although the average price of coal delivered to the electric power sector declined in both 2012 and 2013, it rose by more than 4% per year from 2007 to 2011, and the resulting increase in operational costs for coal-fired power plants reinforced the impacts of lower demand and more competitive natural gas prices.

When faced with declining profitability, plant owners may choose to retire their units rather than make additional investments to keep them operating. In the AEO2014 Reference case, all coal-fired plants are required to have either a scrubber or a dry sorbent injection (DSI) system combined with a fabric filter in order to continue operating in 2016 [8] and later years. As of the end of 2012, 64% of the U.S. fleet of coal-fired generators was compliant with this requirement. The remaining plant owners are in the process of deciding whether to retrofit or retire their plants [9].

The outlook for nuclear power also has been altered by the changing conditions in U.S. electricity markets. Nuclear power plants have lower fuel costs than either coal- or natural gas-fired plants, translating to lower variable operating costs and ensuring that they are dispatched when available. The spread between the price of electricity and the fuel cost for nuclear plants is often referred to as the quark spread. Nuclear power plant owners in wholesale markets rely on sufficient quark spreads to cover nonfuel operations, maintenance, and any new capital expenses associated with the plants to provide a return on their investment. Lower wholesale electricity prices have reduced quark spreads for all nuclear power plants, especially those with increasing operations and maintenance (O&M) costs or capital addition costs.

The AEO2014 Reference case assumes an additional 6 GW of generic nuclear retirements from 2012 to 2019, beyond the six reactor retirements already announced (a total that includes the Oyster Creek plant), as higher-cost units face continued economic challenges. Those projected retirements are represented by derating of existing capacity for plants in vulnerable regions, not by

retiring any specific plants. Higher natural gas prices in the Reference case after 2020 support the continued operation of the U.S. nuclear fleet and limit retirements from 2020 through 2040.

### Accelerated retirement cases

AEO2014 includes several cases designed to explore the effects of alternative assumptions that change projected natural gas prices or electricity demand, or assigns a value to carbon dioxide ($CO_2$) emissions as a proxy for possible future policies to mitigate greenhouse gas emissions. However, those cases have impacts throughout the energy system and the economy, which makes it difficult to measure the independent effects of significant coal and nuclear capacity retirements. In order to isolate the effects of additional retirements on the energy system, several cases were developed by incorporating assumptions that directly accelerate retirements of coal-fired and nuclear power plants.

#### Accelerated Coal Retirements case

The AEO2014 High Coal Cost case assumes a decrease in coal mine productivity and an increase in coal transportation costs, causing coal prices to rise to a level 68% above those in the Reference case in 2040. In the Reference and High Coal Cost cases, real O&M costs are flat, which is consistent with long-term historical trends. However, as coal plants age, higher O&M costs may also become a concern because replacement parts and upgrades to plant equipment could be required to keep them operating effectively. In the Accelerated Coal Retirements case, the assumptions of the High Coal Cost case are combined with an assumed 3% annual increase in real O&M costs for coal-fired power plants from 2012 through 2040, with the increase intended to represent the high end of potential future O&M costs. The higher fuel prices and O&M costs in the Accelerated Coal Retirements case serve as proxies for any combination of factors that would produce a higher rate of coal plant retirements.

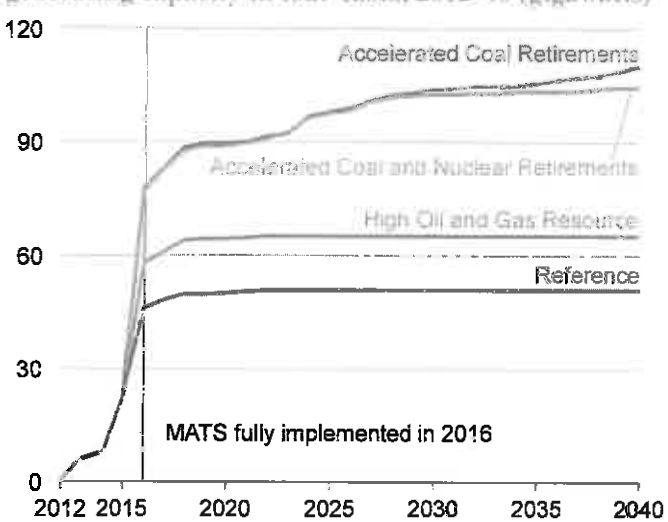
#### Accelerated Nuclear Retirements case

The Nuclear Regulatory Commission (NRC) has the authority to issue initial operating licenses for commercial nuclear power plants for a period of 40 years and then to extend them in 20-year increments. The NRC has already approved initial 20-year license extensions for more than 70% of the nuclear fleet, and the AEO2014 Reference case assumes that each plant will receive a first license extension unless its planned retirement has specifically been reported. The nuclear power industry currently is developing strategies to submit license applications for additional 20-year life extensions that would allow plants to continue operating beyond 60 years. The AEO2014 Reference case assumes that plants reaching 60 years of age between 2030 and 2040 will be granted a second life extension.

Nuclear power plants operate as baseload capacity. Although they are expensive to build and maintain, they have relatively low variable operating costs, which ensures that they are dispatched when available. While not affecting their dispatch order, increases in nonfuel O&M costs can have negative effects on the economics of nuclear power plants through lower profit margins. To avoid retirement for economic reasons, a plant must maintain a positive net present value over its operating lifetime. As with coal plants, annual O&M costs for nuclear power plants remain flat in the AEO2014 Reference case. However, recent data suggest that O&M costs for nuclear plants rose at an average annual rate of 4% over the 2008-12 period [*10*].

The Accelerated Nuclear Retirements case assumes that O&M costs for nuclear power plants grow by 3% per year through 2040; that all nuclear plants not retired for economic reasons are retired after 60 years of operation; and that no additional nuclear power plants are built after the 5.5 GW of capacity currently under construction is completed. This case reflects uncertainty regarding actions and costs associated with continued operation of the existing nuclear fleet.

**Figure IF6-1. Cumulative retirements of coal-fired generating capacity in four cases, 2012-40 (gigawatts)**




#### Accelerated Coal and Nuclear Retirements case

Large-scale simultaneous retirements of both coal-fired and nuclear capacity could have a significant effect on the electric power system. In order to assess that potential effect, the AEO2014 Accelerated Coal and Nuclear Retirements case combines the assumptions of the Accelerated Coal Retirements case and the Accelerated Nuclear Retirements case.

### Results

#### Retirements

In the Accelerated Coal Retirements case, 110 GW of capacity, or 117% more than in the Reference case, is retired by 2040 (Figure IF6-1). In the Accelerated Coal and Nuclear Retirements case, coal retirement levels are similar to those in the Accelerated Coal Retirements case through 2030, with a slight leveling off toward the end of the projection, when some coal-fired capacity is needed to make up for the lost nuclear capacity.

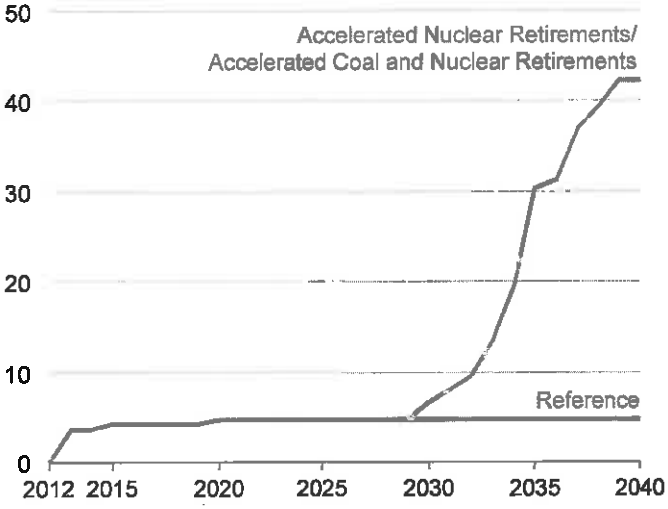
In the Accelerated Nuclear Retirements case, 42 GW of nuclear capacity is retired through 2040 (Figure IF6-2). However, other than retirements early in the projection, there is no significant reduction in nuclear capacity before the plants begin to reach their 60th year of operation, in 2029. The same retirement trajectory is repeated in the Accelerated Coal and Nuclear Retirements case.

There is no incremental increase in nuclear retirements in the Accelerated Nuclear Retirements, despite higher O&M costs. However, incremental retirements do occur in the Low Nuclear case, discussed in the Market Trends section of the AEO2014. The Low Nuclear case uses the same assumptions as the Accelerated Nuclear Retirements case, but also includes the resource assumptions from the High Oil and Gas Resource case that result in lower natural gas prices than in the Reference case. As a result, economic retirements of nuclear power plants that have not operated for 60 years do occur in the last decade of the projection in the Low Nuclear case, with nuclear capacity falling to 35 GW below the levels in the Accelerated Coal and Nuclear Retirements case.

### Capacity additions

In order to replace capacity that is retired in the accelerated retirement cases, more total capacity (including capacity in the electric power sector, combined heat and power, and capacity in the end-use sectors) is added than in the Reference case. The new capacity mix consists almost entirely of natural gas and renewable energy sources (Figure IF6-3). Natural gas-fired combined-cycle units are favored because of their low fuel prices and relatively moderate capital costs.

Figure IF6-2. Cumulative retirements of nuclear generating capacity in three cases, 2012-40 (gigawatts)




### Generation fuel mix

As existing coal and nuclear plants are retired, natural gas and renewables gain increasing shares of the generation mix (Figure IF6-4). The strength of this trend depends on how much nuclear and coal-fired capacity is retired.

Coal-fired generation in 2040 is lowest in the Accelerated Coal Retirements case, which results in the greatest total loss of coal-fired capacity. In all AEO2014 cases, including the Reference case, available coal-fired capacity operates as baseload generation throughout the projection. Therefore, removing coal capacity results in lower overall levels of generation. Coal-fired electricity generation in 2040 is 1% higher in the Accelerated Nuclear Retirements case than in the Reference case as a result of a small increase in coal-fired capacity installed at the end of the projection period.

Nuclear power plants also consistently operate as baseload generation, and their total generation varies with changes in capacity. In the Accelerated Nuclear Retirements and Accelerated Coal and Nuclear Retirements cases, nuclear

Figure IF6-3. Cumulative additions of electricity generating capacity by fuel in four cases, 2012-40 (gigawatts)

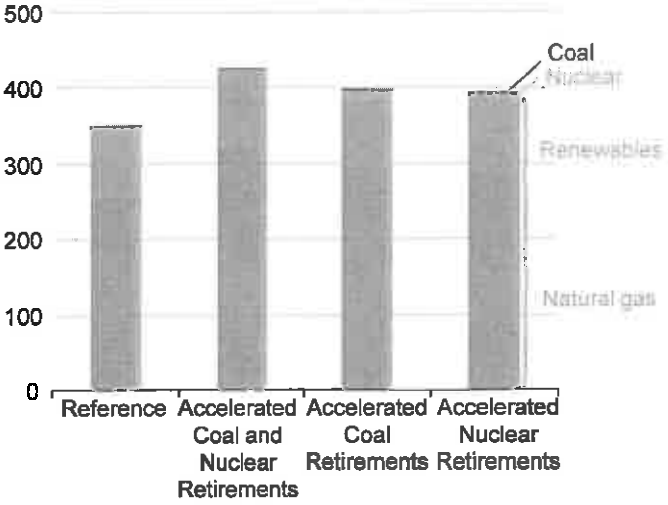
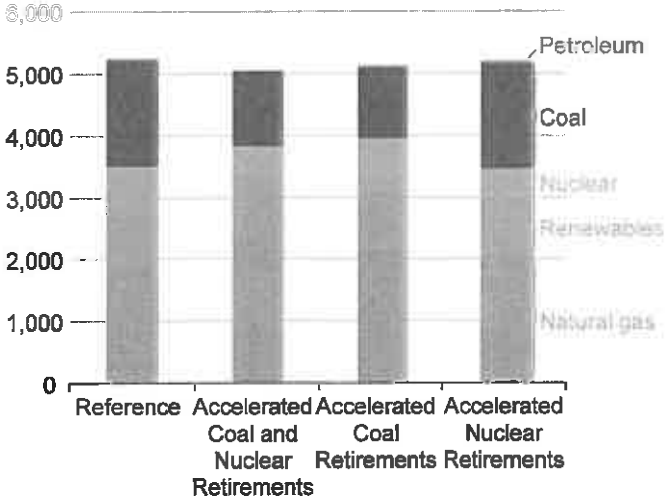



Figure IF6-4. Electricity generation by fuel in four cases, 2040 (billion kilowatthours)



generation in 2040 is 40% lower than in the Reference case. In the Accelerated Coal Retirements case, nuclear electricity generation is 2% above the Reference case level in 2040.

### Natural gas prices

In all the AEO2014 accelerated retirement cases, natural gas prices are higher in most years than in the Reference case as retirements of existing coal and nuclear capacity lead to both increased use of existing natural gas-fired plants and the development of new plants. The alternative cases with the largest increases in natural gas-fired generation also have the largest price increases. For example, the price of natural gas delivered to the electric power sector in 2040 in the Accelerated Coal and Nuclear Retirements case is 11% higher than the Reference case price (Figure IF6-5) [11].

### Carbon dioxide emissions in the electric power sector

Coal and natural gas are the primary sources of $CO_2$ emissions from the electric power sector. Coal is the most significant contributor, emitting more than twice as much $CO_2$ per megawatthour (mWh) as a combined-cycle plant fueled by natural gas. Generation using nuclear power and renewables does not emit $CO_2$.

Because of the high $CO_2$ intensity of coal, scenarios that result in less coal-fired electricity generation also result in the most significant emissions reductions. Total electric power sector $CO_2$ emissions in the Accelerated Coal Retirements case are 20% below those in the Reference case in 2040 (Figure IF6-6). Emissions are slightly higher in the Accelerated Coal and Nuclear Retirements case, because some nuclear power generation is replaced by gas-fired generation; however, the effect of the coal-fired capacity retirements still keeps emissions 14% below the Reference case level in 2040. In the Accelerated Nuclear Retirements case, nuclear generation is 328 mWh below the Reference case level in 2040, while electric power sector $CO_2$ emissions are 85 million metric tons higher, reflecting an average increase of 0.26 metric tons $CO_2$ per mWh reduction in nuclear generation across the two scenarios. The estimated increase in $CO_2$ emissions per mWh of nuclear generation reduced, which is slightly below the estimated increase in $CO_2$ emissions per additional mWh of generation from advanced combined-cycle plants burning natural gas, reflects replacement generation from natural gas and renewables, together with some reduction in overall electricity demand as a result of higher end-user prices.

### Retail electricity prices

Retail electricity prices vary in the accelerated retirement cases, because natural gas prices are a key determinant of wholesale electricity prices, which in turn are a significant component of retail electricity prices. Accordingly, the cases with the highest delivered natural gas prices also show the highest retail electricity prices (Figure IF6-7). In 2040, real retail electricity prices in the Accelerated Coal and Nuclear Retirements case are 12% higher than those in the Reference case.

## Conclusions

Accelerated retirements of coal-fired and nuclear electricity generation capacity would cause natural gas and renewables to gain an increased share in the nation's electricity generation mix. Natural gas is most often the lowest-cost option for replacement capacity, while renewable generation grows, spurred by the increased economic competitiveness of solar and wind technologies toward the end of the projection period. The rising use of natural gas in the electric power sector results in price increases for both natural gas and electricity in all sectors relative to the Reference case (Table IF6-1).

Figure IF6-5. Delivered price of natural gas to the electric power sector in four cases, 2012, 2025, and 2040 (2012 dollars per thousand cubic feet)

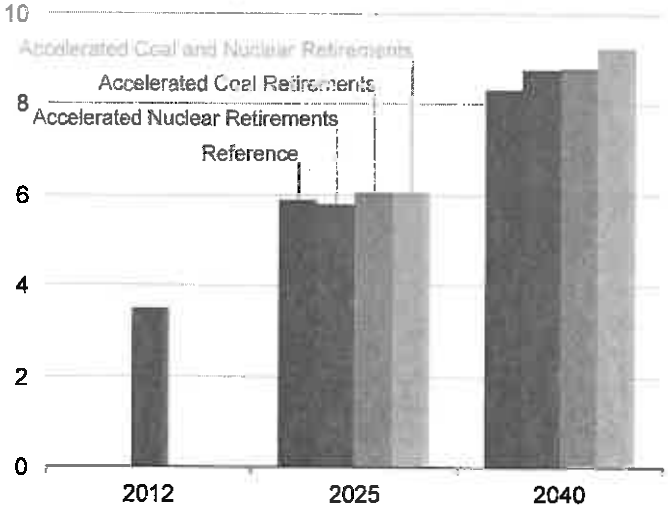



Figure IF6-6. Electric power sector carbon dioxide emissions in four cases, 2012-40 (million metric tons per year)

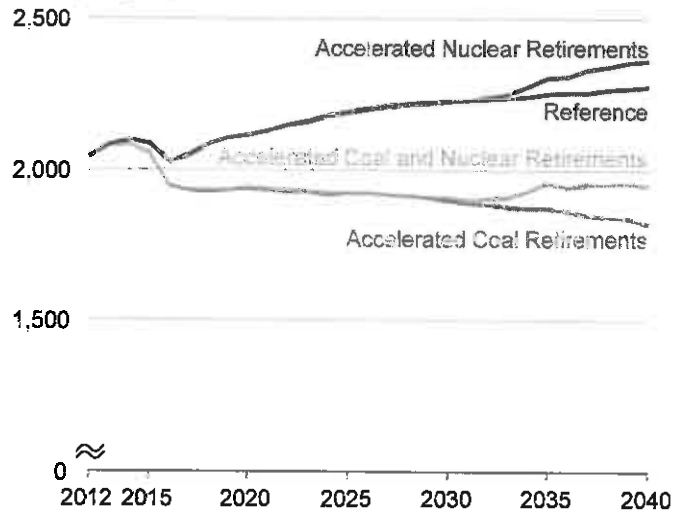
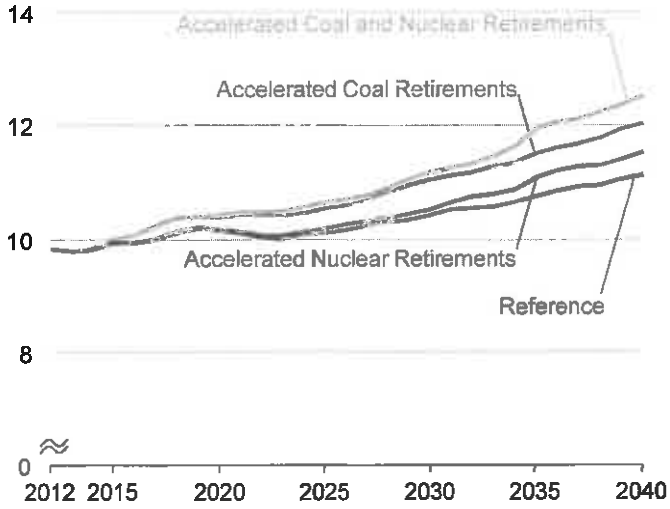


Figure IF6-7. Average retail electricity prices in four cases, 2012-40 (2012 cents per kilowatthour)




Effects on $CO_2$ emissions depend on the technology retired. Because a natural gas-fired combined-cycle plant emits less than half as much $CO_2$ as a plant fueled with pulverized coal, accelerated retirements of coal-fired plants result in lower $CO_2$ emissions compared with the Reference case. In contrast, because nuclear power plants emit no $CO_2$, accelerated retirements of nuclear power plants raise $CO_2$ emissions compared with the Reference case.

Table IF6-1. Average delivered natural gas prices, electricity prices, and carbon dioxide emissions in four cases, 2012, 2025, and 2040

| Year and case | Average delivered natural gas price to power sector (2012 dollars per million Btu) | Retail electricity price (2012 cents per kilowatthour) | Electric power sector carbon dioxide emissions (million metric tons) |
|---|---|---|---|
| 2012 | 3.44 | 9.8 | 2,039 |
| 2025 | | | |
| Reference | 5.76 | 10.1 | 2,194 |
| Accelerated Coal Retirements | 5.91 | 10.5 | 1,925 |
| Accelerated Nuclear Retirements | 5.69 | 10.2 | 2,188 |
| Accelerated Coal and Nuclear Retirements | 5.92 | 10.6 | 1,923 |
| 2040 | | | |
| Reference | 8.16 | 11.1 | 2,271 |
| Accelerated Coal Retirements | 8.60 | 12.0 | 1,821 |
| Accelerated Nuclear Retirements | 8.57 | 11.5 | 2,356 |
| Accelerated Coal and Nuclear Retirements | 8.03 | 12.5 | 1,946 |

# Endnotes for IF6

**Links current as of April 2014**


1. Entergy, "Entergy to close, decommission Vermont Yankee" (Press Release, August 27, 2013; accessed March 25, 2014), http://www.entergy.com/news_room/newsrelease.aspx?NR_ID=2769.
2. Exelon Corporation, "Exelon to retire Oyster Creek generating station in 2019" (Press Release, December 8, 2010; accessed March 25, 2014), http://www.exeloncorp.com/newsroom/pr_20101208_Nuclear_OysterCreekRetirement.aspx.
3. M. Wallace and G.D. Banks, *Restoring U.S. Leadership in Nuclear Energy* (Center for Strategic & International Studies, Washington, DC, June 2013), http://csis.org/publication/restoring-us-leadership-nuclear-energy.
4. The U.S. Energy Information Administration analysis assumes competitive economics for electric power capacity, in which variable costs determine dispatch, and fixed costs must also be paid by electric sales revenue to continue operation over the long term.
5. Capacity payments provide units with revenue for being available to run in order to ensure reliability. Capacity payments can account for a significant portion of revenue for peak load plants, which do not run often and require financial incentives to remain available for dispatch.
6. U.S. Energy Information Administration, "Dark spreads measure returns over fuel costs of coal-fired generation," *Today In Energy* (February 20, 2013), http://www.eia.gov/todayinenergy/detail.cfm?id=10251.
7. U.S. Energy Information Administration, "Electric generator dispatch depends on system demand and the relative cost of operation," *Today In Energy* (August 17, 2012), http://www.eia.gov/todayinenergy/detail.cfm?id=7590.
8. U.S. Energy Information Administration, "Assumptions to AEO2014: Electricity Market Module" (forthcoming), http://www.eia.gov/forecasts/aeo/assumptions/.
9. S. Ferris, "Hatfield's Ferry Power Station quietly closes for good," *Herald Standard* (Uniontown, PA, October 20, 2013), http://www.heraldstandard.com/new_today/hatfields-ferry-power-station-quietly-closes-for-good/article_cd0133e1-9adb-5b12-8f8d-5676ede34636.html. Installing control equipment does not guarantee that a plant will remain economical to continue operating. Retirement of the Hatsfield's Ferry power station in Pennsylvania was announced after installation of a $650 million FGD scrubber system in 2009. However, in the AEO2014 Reference case most coal-fired power plants continue operating despite the regulatory hurdle of MATS in 2016.
10. Electric Utility Cost Group (EUCG), via Nuclear Energy Institute, "Annual briefing for the financial community" (February 13, 2014), http://www.nei.org/Issues-Policy/Economics/Financial-Analyst-Briefings/Nuclear-Energy-in-2014-Status-and-Outlook.
11. The 2025 average price of natural gas price delivered to the electric power sector in the Accelerated Nuclear Retirements case is slightly lower than the price in the Reference case due to a decline in LNG export capacity additions. The retirement of nuclear capacity in the Accelerated Nuclear Retirements case after 2030 causes an increase in demand from the electric power sector, resulting in higher natural gas prices, and the anticipation of higher prices reduces the economic competitiveness of LNG export facilities, lowering LNG export projections. This results in lower natural gas prices in the Accelerated Nuclear Retirements case between 2022 and 2032, because less natural gas is exported. Demand from the power sector does not change significantly from the Reference case until significant amounts of nuclear capacity are retired.

# Figure and table sources for IF6

**Links current as of April 2014**

**Figure IF6-1. Cumulative retirements of coal-fired generating capacity in four cases, 2012-40. Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCCSTOM.D012314A, HCLONUC.D012314A, and HIGHRESOURCE.D112913B.

**Figure IF6-2. Cumulative retirements of nuclear generating capacity in three cases, 2012-40. Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, LOWNUC14.D012314B, and HCLONUC.D012314A.

**Figure IF6-3. Cumulative additions of electricity generating capacity by fuel in four cases, 2012-40: Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCLONUC.D012314A, HCCSTOM.D012314A, and LOWNUC14.D012314B.

**Figure IF6-4. Electricity generation by fuel in four cases, 2040. Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCLONUC.D012314A, HCCSTOM.D012314A, and LOWNUC14.D012314B.

**Figure IF6-5. Delivered price of natural gas to the electric power sector in four cases, 2012, 2025, and 2040. History:** U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCLONUC.D012314A, HCCSTOM.D012314A, and LOWNUC14.D012314B.

**Figure IF6-6. Electric power sector carbon dioxide emissions in four cases, 2012-40. Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCLONUC.D012314A, HCCSTOM.D012314A, and LOWNUC14.D012314B.

**Figure IF6-7. Average retail electricity prices in four cases, 2012-40. Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCLONUC.D012314A, HCCSTOM.D012314A, and LOWNUC14.D012314B.

**Table IF6-1. Average delivered natural gas prices, electricity prices, and carbon dioxide emissions in four cases, 2012, 2025, and 2040. History:** U.S. Energy Information Administration, *Monthly Energy Review September 2013,* DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, runs REF2014.D102413A, HCLONUC.D012314A, HCCSTOM.D012314A, and LOWNUC14.D012314B.

## IF7. Renewable electricity projections show growth under alternative assumptions in AEO2014

In the AEO2014 Reference case, renewable electricity generation grows by 69% from 2012 to 2040, including an increase of more than 140% in generation from nonhydropower renewable energy sources. Renewables are collectively the fastest-growing source of electricity generation in the projection, with annual growth rates that exceed the growth rate for natural gas-fired generation. However, because renewables start from a relatively low 12% market share of total generation, their contribution to U.S. total electricity generation is just 16% in 2040 in the Reference case, well below the natural gas and coal shares of 35% and 32%, respectively (Figure IF7-1).

The AEO2014 Reference case is based on current laws and policies, as well as on known technology and demographic trends. Projections of nonhydropower [1] renewable electricity generation are sensitive to assumptions about government policies and external market factors. Key uncertainties affecting projected growth include expiration of policies that affect financial incentives for deployment or operation of particular technologies, the costs and performance of the technologies, the costs of competing generation sources, and macroeconomic conditions that affect growth in electricity demand (including GDP growth).

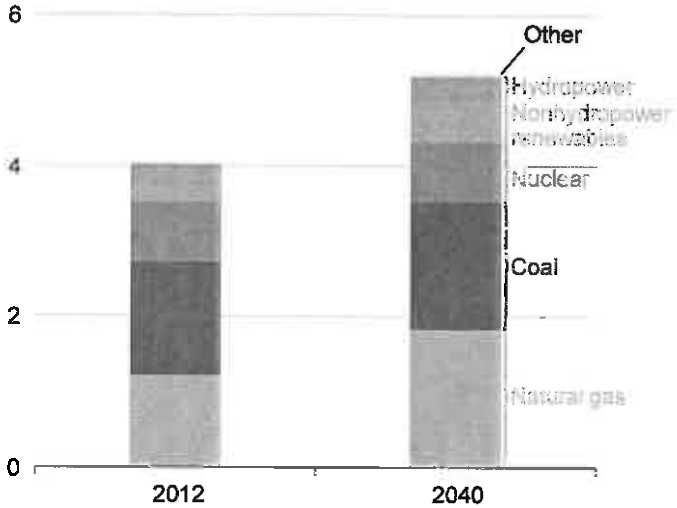
The renewable energy policy landscape is particularly dynamic compared to that of more-established energy sources, as new and existing policies continue to be created and adjusted at the federal, state, and local levels. In addition, policies that affect competing sources of generation, such as natural gas and coal, can have significant impacts on renewable generation projects. For example, placing an explicit or implicit value on carbon dioxide ($CO_2$) emissions would make the cost of operating fossil-fueled capacity higher, improving the relative economics of renewables.

From 2005 to 2012, nonhydropower renewable generation more than doubled, encouraged by policies such as federal tax credits and grants, state renewable portfolio standards (RPS), and a variety of other state and local policies such as rebates, tax incentives, financing assistance, net metering, and interconnection standards. For example, the federal production tax credit (PTC), which most recently applied to wind, geothermal, biomass, hydro, certain waste technologies, and marine energy projects under construction by the end of 2013, was first established by the Energy Policy Act of 1992. Since that time, the tax credit has been revised periodically—expiring several times and then subsequently being renewed. Most recently, the credit expired at the end of 2013 and has not been extended as of early 2014. Trade groups and renewable supporters continue to advocate for an extension to the 2013 deadline, but the AEO2014 Reference case assumes no such extension.

Assumptions about the cost and performance of renewable technologies also affect the projections, particularly as some renewable technologies become more economically competitive in some regions. Determination of future or even current technology costs can be a challenge. For example, in the case of solar photovoltaic (PV) technologies, there is enough variation among current projects in terms of geographic locations, technologies, developer experience, and regulatory frameworks that even the most carefully developed estimates will overstate actual costs for some projects and understate costs for others. While PV capital costs have declined over the past decade, there is continuing uncertainty about both the degree and pace of future cost declines.

Projections for generation with renewables are sensitive to the prices of competing generation sources and other market factors, particularly in later years of the projection period, when the projected trends in renewable generation are increasingly influenced by economic rather than policy factors. In some regions and projection years, renewable resources like wind or solar may represent the marginal source of capacity growth, which makes renewables sensitive to price swings in competing resources as well as to broader economic or market fluctuations. In order to address such uncertainties, AEO2014 includes alternative cases to provide insight regarding the direction and magnitude of sensitivities in the projections. Table IF7-1 shows key technology, policy, economic, and market uncertainties and shows how they are addressed in a selected group of AEO2014 alternative cases (described in more detail in Appendix E).

Figure IF7-1. Total U.S. electricity generation by energy source, 2012 and 2040 (billion kilowatthours)




The Low Renewable Technology Cost case assumes that renewable technology capital costs are 20% lower than in the Reference case. The No Sunset case assumes the extension of existing federal energy policies that contain sunset provisions—in particular the production and investment tax credits for certain renewable electricity generation technologies. The GHG25 case assumes a policy that applies a fee on carbon dioxide emissions (in 2012 dollars) starting at $25 per metric ton in 2015 and escalating by 5% per year to about $85 per metric ton in 2040. The High Oil and Gas Resource case adjusts oil and gas resource and productivity assumptions that result in natural gas prices to the electric power sector in 2040 that are 37% lower than in the Reference case. The Low Oil and Gas Resource case adjusts assumptions about oil and gas resources that result in natural gas prices to the electric power sector in 2040 that are 33%

higher than in the Reference case. The High Economic Growth and Low Economic Growth cases assume higher and lower levels of real GDP growth from 2012 to 2040 than in the Reference case.

Figure IF7-2 shows projected total nonhydropower renewable generation from 2012 to 2040 in the selected alternative cases. The results vary significantly, particularly in the later years of the projection. For example, in the GHG25 case total nonhydropower renewable generation in 2040 is 83% higher than in the Reference case, and in the High Oil and Gas Resource case total nonhydropower renewable generation in 2040 is 12% lower than in the Reference case.

Some of the assumptions used in the AEO2014 alternative cases can lead to significant increases in long-term growth of renewable electricity generation. However, alternative cases with assumptions that are less favorable to renewables growth, such as the Low Economic Growth case (with slower electricity demand growth) and the High Oil and Gas Resource case (with lower natural gas prices) are unlikely to result in renewable projections that fall drastically below those in the Reference case—in large part because state renewable portfolio standards (RPS) effectively establish a floor for generation with renewables. RPS policies generally require that a minimum share of generation must come from renewable sources, and even with slow load growth or competition from low-cost alternative generation resources, renewable generation must be sufficient to meet the RPS target. On the other hand, as renewable generation sources become increasingly competitive after 2025, a favorable shift in assumptions may result in an impact that does not have a limit on the upper bound, allowing for stronger growth in renewable generation than is projected in the Reference case.

In addition, long-term projections are more sensitive to changes in assumptions than are near-term projections. Although the range of renewable generation in 2040 across the alternative cases is large, the 2025 projections for total renewable generation are within 15% of the Reference case in all the alternative cases except for the GHG25 case. Near-term growth in renewable generation is constrained by a combination of factors that generally hold across most sensitivity analyses: growth in electricity demand continues at a relatively low annual rate (less than 1% per year in the Reference case) compared with historical levels, and generating capacity required to meet demand and reserve requirements in many regions already exceeds near-term requirements at the start of the projection period. As a result, demand for new generating capacity of any type in the first decade of the projection is minimal in most regions. From 2012 to 2025, total generating capacity—including renewables, fossil fuels, and nuclear—increases by only 4%. However, as renewable technologies become more economically competitive, they capture a larger share of the growing market. In addition, even with low rates of electricity demand growth, the presence of a significant and growing fee on $CO_2$ emissions creates enough pressure early in the projection period to spur significant growth of renewable generation in the near term.

Alternative assumptions that lead to greater penetration of electricity markets by renewable energy sources—namely, those in the No Sunset, Low Renewable Technology Cost, GHG25, Low Oil and Gas Resource, and High Economic

Figure IF7-2. Nonhydropower renewable electricity generation in eight cases, 2005-40 (billion kilowatthours)

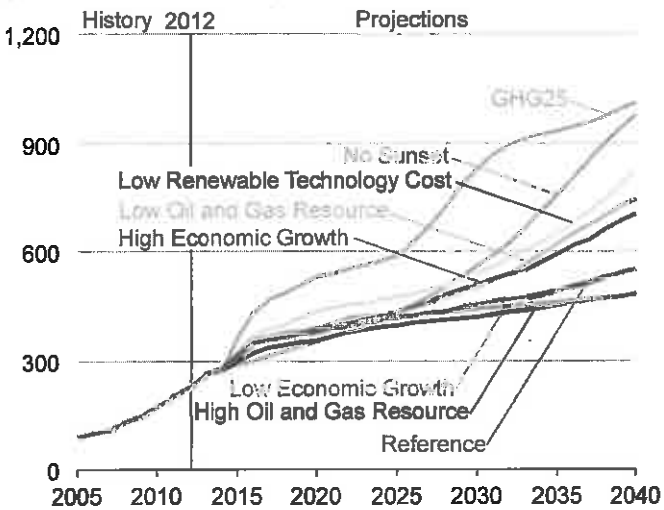



Table IF7-1. Sources of uncertainty and variation in AEO2014 projections for renewable electricity generation

| Key uncertainties | Selected AEO2014 alternative cases | Uncertainties not addressed in AEO2014 alternative cases |
|---|---|---|
| **Technology:** Cost assumptions for renewable technologies. | Low Renewable Technology Cost | Breakthroughs in new or emerging renewable (e.g., wave/tide/ocean) or complementary (e.g., storage) technologies |
| **Policy:** Current policies may not expire as scheduled; future policies may impose direct or indirect fees on carbon dioxide emissions. | No Sunset<br>GHG25 (carbon dioxide fee case) | Existing policies not explicitly modeled in AEO2014 that are more specific or geographically specialized (e.g., net metering, local rebate programs, and technology-specific set-asides in state RPS programs); other new policies that could be introduced |
| **Macroeconomics and prices:** Macroeconomic growth rates and natural gas prices. | High Oil and Gas Resource<br>Low Oil and Gas Resource<br>High Economic Growth<br>Low Economic Growth | Competition from other fuels; sector- or region-specific economic factors; unexpected shifts in demand |

Growth cases—do not have proportionate effects on all renewable technologies (Figures IF7-3 through IF7-6). Generation from solar and wind installations generally increases by more compared with the Reference case than does generation from biomass, waste, and geothermal sources. Solar generation in 2040 in most of the alternative cases is more than double the Reference case level. Wind starts from a much larger installed capacity base, so the percentage growth in wind generation is lower than for solar, but in all five alternative cases wind generation in 2040 is at least 20% higher than projected in the Reference case.

Solar and wind energy are expected to remain the primary sources of renewable capacity growth. Although geothermal, waste, and biomass resources have some favorable characteristics compared to wind and solar, such as the ability to provide operator-dispatched power, each has significant limitations. The limitations include a limited resource base (geothermal, waste) or relatively high capital and/or fuel costs (biomass). Although wind and solar will continue to be capital-intensive technologies, they are expected to achieve cost reductions that—along with a larger resource base—result in higher growth than other renewables under favorable conditions (such as placement of an explicit or implicit value on $CO_2$ emissions, or high natural gas prices). However, solar and wind resources also vary in availability and quality by region, and generation facilities are likely to be concentrated in the more favorable regions.

Even in the alternative cases that result in higher levels of market penetration for renewable generation technologies, the results are limited by the selection of technologies currently modeled by the U.S. Energy Information Administration. The AEO2014 alternative cases cannot be used to evaluate potential technologies that are not characterized in the National Energy Modeling

Figure IF7-3. Electricity generation from wind power in eight cases, 2012, 2020, 2030, and 2040 (billion kilowatthours)

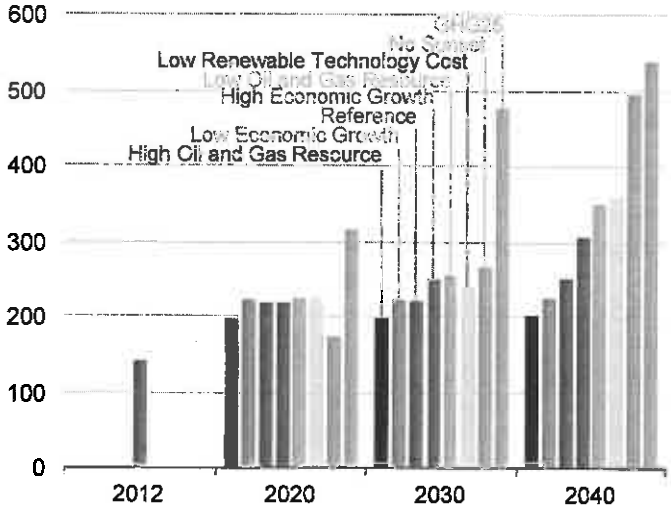



Figure IF7-4. Electricity generation from solar power in eight cases, 2012, 2020, 2030, and 2040 (billion kilowatthours)

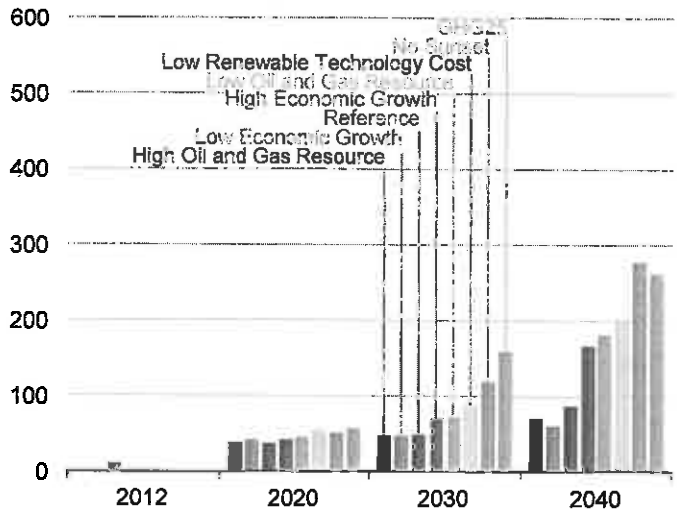



Figure IF7-5. Electricity generation from geothermal power in eight cases, 2012, 2020, 2030, and 2040 (billion kilowatthours)

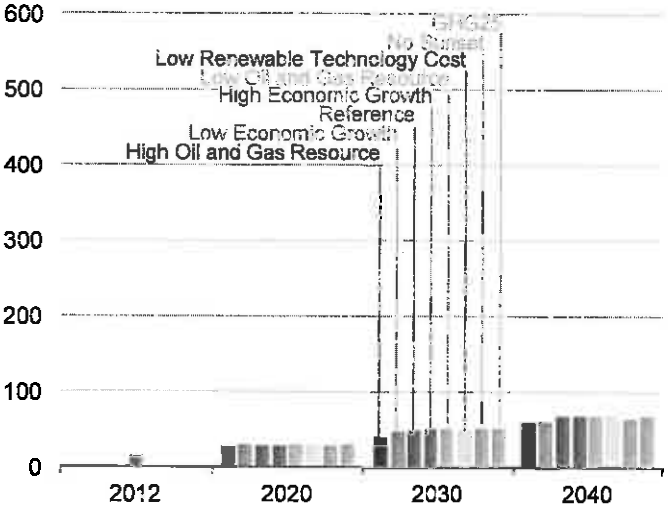
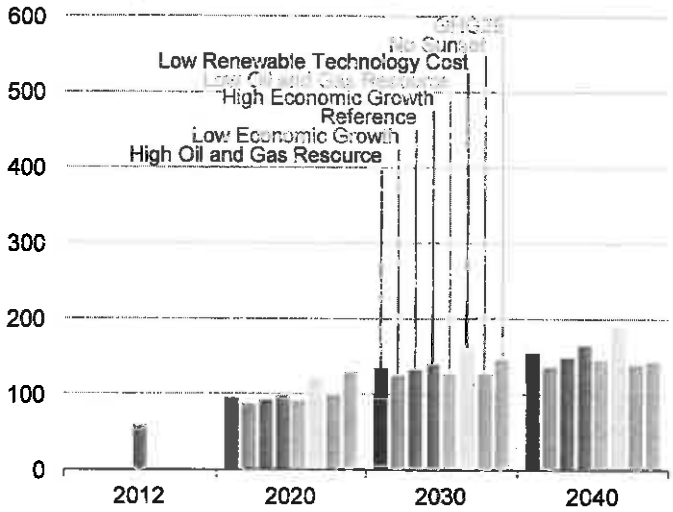



Figure IF7-6. Electricity generation from biomass and waste power in eight cases, 2012, 2020, 2030, and 2040 (billion kilowatthours)



System. Some emerging renewable technologies not included in AEO2014 include engineered geothermal systems, marine hydrokinetics (such as wave energy), in-stream hydroelectric, and hybrid solar thermal combined cycle.

Similarly, no new electricity storage technologies are included in the projections. Electricity storage represents one of several options for accommodating high levels of intermittent generation from wind and solar resources. Because such technologies, other than pumped hydro storage, generally are either in early stages of development or not yet commercially established, impacts on electricity markets in the near- to mid-term period are difficult to model.

The AEO2014 alternative cases typically examine the effects of changing single assumptions within a moderate range of uncertainty, and they are not intended to be interpreted as bounding cases. For example, a compound case incorporating high natural gas prices, low renewable technology costs, and an explicit or implicit value for $CO_2$ emissions could be expected to result in additional renewable generation growth, although the impact would not necessarily be the sum of the results of the individual cases. The same could be true if any of the individual alternative cases were examined using different assumptions—for example, if renewable technology costs were assumed to be 50%, rather than 20%, below the costs used in the Reference case.

## Endnotes for IF7

**Links current as of April 2014**

1. Hydropower has resource-specific characteristics that separate it from other renewable energy sources. It is projected to remain close to current capacity and generation levels in the cases considered here.

## Figure and table sources for IF7

**Links current as of April 2014**

**Figure IF7-1. Total U.S. electricity generation by fuel, 2012 and 2040: History:** U.S. Energy Information Administration, *Monthly Energy Review September 2013*, DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). Projections: AEO2014 National Energy Modeling System, run REF2014.D102413A.

**Table IF7-1. Sources of uncertainty and variation in AEO2014 projections for renewable electricity generation:** U.S. Energy Information Administration.

**Figure IF7-2. Nonhydropower renewable electricity generation in eight cases, 2005-40: History:** U.S. Energy Information Administration, *Monthly Energy Review September 2013*, DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, CO2FEE25.D011614A, NOSUNSET.D121713A, LCR_2014.D120613A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

**Figure IF7-3. Electricity generation from wind power in eight cases, 2012, 2020, 2030, and 2040: History:** U.S. Energy Information Administration, *Monthly Energy Review September 2013*, DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, CO2FEE25.D011614A, NOSUNSET.D121713A, LCR_2014.D120613A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

**Figure IF7-4. Electricity generation from solar power in eight cases, 2012, 2020, 2030, and 2040: History:** U.S. Energy Information Administration, *Monthly Energy Review September 2013*, DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, CO2FEE25.D011614A, NOSUNSET.D121713A, LCR_2014.D120613A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

**Figure IF7-5. Electricity generation from geothermal power in eight cases: History:** U.S. Energy Information Administration, *Monthly Energy Review September 2013*, DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, CO2FEE25.D011614A, NOSUNSET.D121713A, LCR_2014.D120613A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

**Figure IF7-6. Electricity generation from biomass and waste power in eight cases: History:** U.S. Energy Information Administration, *Monthly Energy Review September 2013*, DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A, CO2FEE25.D011614A, NOSUNSET.D121713A, LCR_2014.D120613A, LOWRESOURCE.D112913A, HIGHRESOURCE.D112913B, LOWMACRO.D112913A, and HIGHMACRO.D112913A.

## IF8. Implications of low electricity demand growth

Although electricity demand fell in only three years between 1950 and 2007, it declined in four of the five years between 2008 and 2012. The largest drop occurred in 2009 (Figure IF8-1). One contributing factor was the steep economic downturn from late 2007 through 2009, which led to a large drop in electricity sales in the industrial sector. Other factors, such as efficiency improvements associated with new appliance standards in the buildings sectors and overall improvement in the efficiency of technologies powered by electricity, have slowed electricity demand growth and may contribute to slower growth in the future, even as the U.S. economy continues its recovery.

In the Reference case, which assumes no new efficiency standards beyond those already in place or announced as final for future implementation as of 2012, total electricity use grows by an average of less than 1% per year from 2012 to 2040. Demand grows across all sectors, with average annual increases in the industrial sector (0.9% per year) slightly higher than those in the residential and commercial sectors (0.7% and 0.8% per year, respectively). As a result of rising demand, 351 gigawatts (GW) of new electricity generating capacity is added from 2012 to 2040, electricity generation increases by 29%, and carbon dioxide ($CO_2$) emissions from the electric power sector increase by 11%.

To examine the energy implications of slower growth of electricity demand, AEO2014 includes a Low Electricity Demand case, in which annual electricity demand in 2040 is only slightly higher than the 2012 level of 3.8 trillion kilowatthours (kWh).

### Low Electricity Demand case

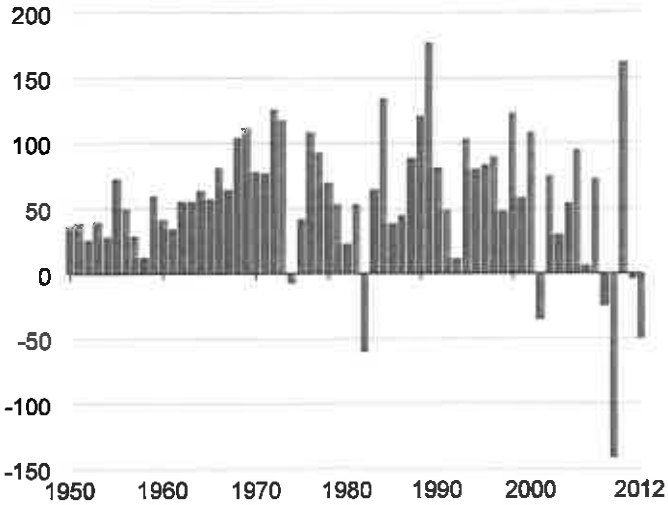
Electricity demand growth depends on economic growth, relative energy prices, and technology choices in the end-use sector, among other factors. Changes in electricity demand result in corresponding changes in electricity generation and the mix of technologies used to meet demand.

The Low Electricity Demand case was developed by assuming changes in technology choices and higher efficiency in the end-use sectors. To limit the number of competing influences, macroeconomic and fuel supply assumptions were unchanged from those in the Reference case. The goals for the Low Electricity Demand case were to identify a combination of technologies that would result in flat demand, and to examine the impacts of stagnant demand on future needs for electricity generation and supply.

The Low Electricity Demand case uses the assumptions incorporated in the Best Available Demand Technology case for both the residential and the commercial sectors, as described in Appendix E and the Market Trends section of this report. The Best Available Demand Technology case assumes that all future equipment purchases in the residential and commercial sectors will be made from a menu of technologies that includes only the most efficient models available in a particular year, regardless of cost. Building shell efficiencies also are assumed to improve relative to the Reference case, and distributed generation costs are assumed to decline much faster than in the Reference case. In addition to those assumptions, the Low Electricity Demand case assumes higher energy savings for electric motors in pumps, fans, and air compressors used in the industrial sector compared with the Reference case. Those adjustments reduce total electric power consumption by electric motors slightly less than 20% over the course of the projection. Although technically plausible, such a drop in electric motor energy usage may not represent a likely path for motor development.

As a result of changes across all end-use sectors in the Low Electricity Demand case, retail electricity sales in 2040 are roughly the same as in 2012. Industrial sales grow slightly from 2012 levels, but a decline in residential sales offsets that growth. Because the distributed generation assumptions in the buildings sector result in higher investment in end-use renewable capacity and generation relative to the Reference case, direct-use generation increases, and there is a 7% increase in total electricity consumption from 2012 to 2040, as compared with 29% in the Reference case (Figure IF8-2).

Figure IF8-1. Annual changes in U.S. electricity demand, 1950-2012 (billion kilowatthours)




### Analysis results

#### Electricity generation capacity

In the Low Electricity Demand case, little new capacity is added in the power sector after planned capacity additions are completed (Figure IF8-3). A significant amount of renewable capacity is added in the end-use sectors as a result of the lower cost assumptions for distributed solar photovoltaics, and a smaller amount of renewable capacity (19% of total renewable additions) is added in the power sector to meet renewable portfolio standards. Total natural gas capacity added is only one-quarter of the amount in the AEO2014 Reference case. Even more so than in the Reference case, there are few new additions of coal or nuclear capacity beyond those already under construction.

With lower demand for electricity, a total of 110 GW of older coal-fired generating capacity is retired between 2013 and 2040 in the Low Electricity Demand case, more than double the 51 GW retired in the Reference case (Figure IF8-4). Most of the retirements occur early in the projection, due to the timing of the Mercury and Air Toxics Standards (MATS), which require a decision to retire or retrofit coal plants to meet environmental standards by 2016. A total of 100 GW of oil- and gas-fired capacity is retired between 2013 and 2040 in the Low Electricity Demand case, compared with 40 GW in the Reference case.

### Electricity generation

Electricity generation in 2040 is 17% lower in the Low Electricity Demand case than in the Reference case, with natural gas-fired generation 472 billion kWh lower and coal-fired generation 343 billion kWh lower. Figure IF8-5 shows total electricity generation from the electric power sector and the end-use sectors, with the contributions broken out for natural gas and renewable generation to display the relative levels of generation from the end-use sectors. As in the Reference case, natural gas-fired generation overtakes coal-fired generation by the end of the projection period, but overall shares for both fuels are lower than in the Reference case. In 2040, the coal share of total generation drops from 37% in 2012 to 32% in the Reference case, and to 31% in the Low Electricity Demand case. The natural gas share, which increases from 30% in 2012 to 35% in 2040 in the Reference case, grows to only 32% in 2040 in the Low Electricity Demand case. Because there is less need for new generating capacity, there is less opportunity for growth in natural gas-fired generation from new plants.

Nuclear electricity generation is slightly lower in the Low Electricity Demand case than in the Reference case, as a result of fewer new builds, but it provides a slightly higher share of total generation than in the Reference case. Renewable generation grows by 60% from 2012 to 2040 in the Low Electricity Demand case, slightly less than the 69% growth in the Reference case, as a large

Figure IF8-2. U.S. total electricity demand by sector in two cases, 2012 and 2040 (billion kilowatthours)

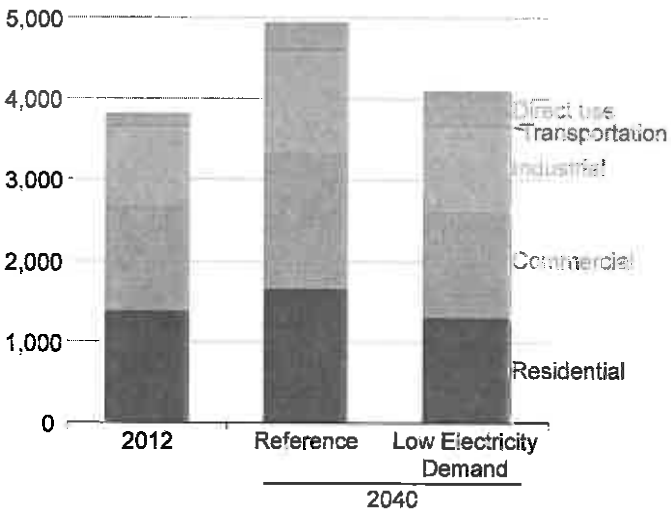



Figure IF8-3. Electricity capacity additions by fuel type in two cases, 2013-40 (gigawatts)

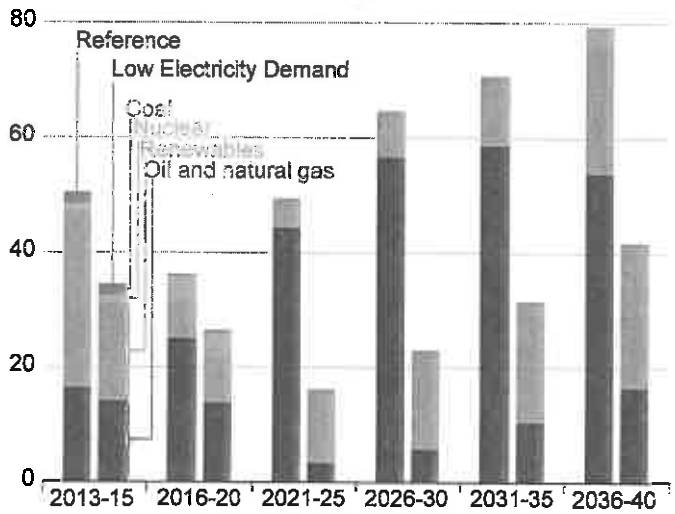



Figure IF8-4. Electric power sector cumulative retirements in two cases, 2013-40 (gigawatts)

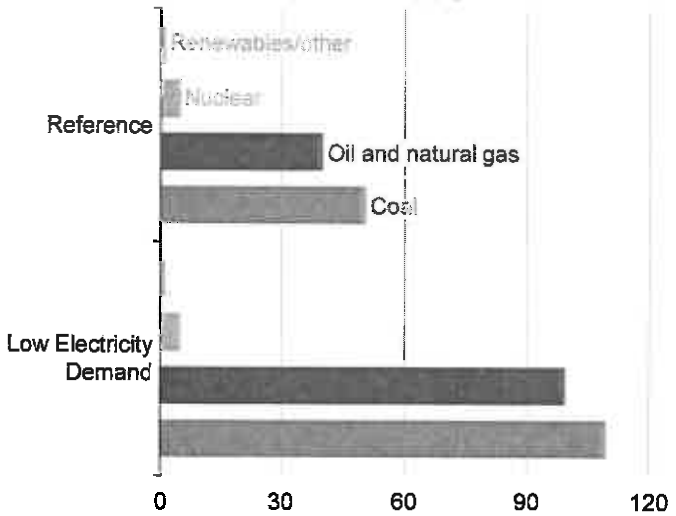
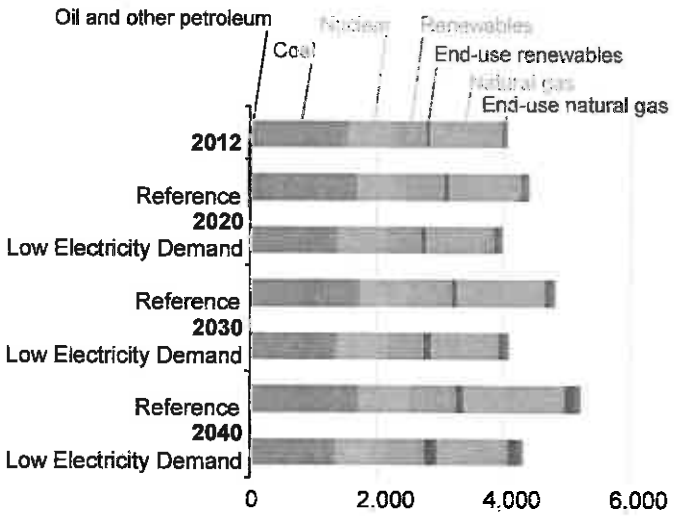



Figure IF8-5. Electricity generation in two cases, 2012-40 (billion kilowatthours)



increase in end-use sector renewable generation offsets much of the decline in renewable generation in the electric power sector compared with the Reference case.

### Emissions

The lower level of generation from fossil fuels in the Low Electricity Demand case results in lower greenhouse gas emissions. In 2020, power sector $CO_2$ emissions are 16% lower than in the Reference case, and in 2040 they are 22% lower (Figure IF8-6). Emissions of other pollutants (sulfur dioxide, nitrogen oxides, and mercury) are also lower than in the Reference case, in proportion to coal-fired generation. The additional retirements of coal-fired capacity in the Low Electricity Demand case begin to occur in 2016, when MATS takes effect. With lower demand and prices for electricity than in the Reference case, it is less economical to install retrofits to comply with the MATS standards. As a result, fewer environmental controls are added.

### Regional impacts

The mix of fuels used to meet U.S. demand for electricity varies across the country, and the initial mix can affect regional projections in the different cases. In general, the West is more reliant on natural gas and renewable generation, the upper Midwest and Central parts of the country are more reliant on coal, the Northeast is more reliant on natural gas and nuclear power, and in the Mid-Atlantic and Southeast there is a mix of generation from coal, nuclear power, and natural gas.

Currently, most coal-fired capacity is installed in two North American Electric Reliability Corporation (NERC) regions: the SERC Reliability Corporation (SERC) region, which covers the Southeast region, and the Reliability First Corporation (RFC) region, which includes most of the Mid-Atlantic and Ohio Valley region [1] (Figure IF8-7). Most of the coal retirements in both the Reference case and the Low Electricity Demand case occur in those regions.

In the RFC region, retirements of coal-fired capacity in the Low Electricity Demand case are double those in the Reference case, and in the SERC region they are nearly triple those in the Reference case. The RFC and SERC regions also contain 67% of the country's current nuclear capacity. However, as in other regions, there are no additional retirements of nuclear capacity in the Low Electricity Demand case relative to the Reference case. As a result, nuclear generation levels are similar in the two cases, and they make up a higher share of the total generation when electricity demand is lower. In SERC, the coal share of total generation in 2040 declines from 38% in the Reference case to 34% in the Low Electricity Demand case, and the nuclear share grows from 23% in the Reference case to 28%. Similarly in the RFC region, the 2040 coal share drops from 44% in the Reference case to 40% in the Low Electricity Demand case, and the 2040 nuclear share rises from 21% to 26%. In both regions the natural gas share also declines slightly in the Low Electricity Demand case relative to the Reference case, because fewer new natural gas-fired power plants are built. Additional retirements of older oil and gas units have less effect on generation than do retirements of coal units, because the oil and gas units typically operate less frequently throughout the year.

In contrast, in regions where there may not be more economical baseload technologies available, coal continues to provide most of the generation needs in 2040, even when electricity demand is assumed to be flat. In the Midwest Reliability Organization (MRO) region, coal-fired plants provided 60% of total generation in 2012, and they still provide 52% in the Reference case and 55% in the Low Electricity Demand case in 2040. With few new natural gas-fired additions projected in the Low Electricity Demand case, coal-fired power plants continue to provide a large portion of the region's total electricity generation.

Figure IF8-6. Carbon dioxide emissions in the electric power sector in two cases, 2012-40 (million metric tons carbon dioxide)

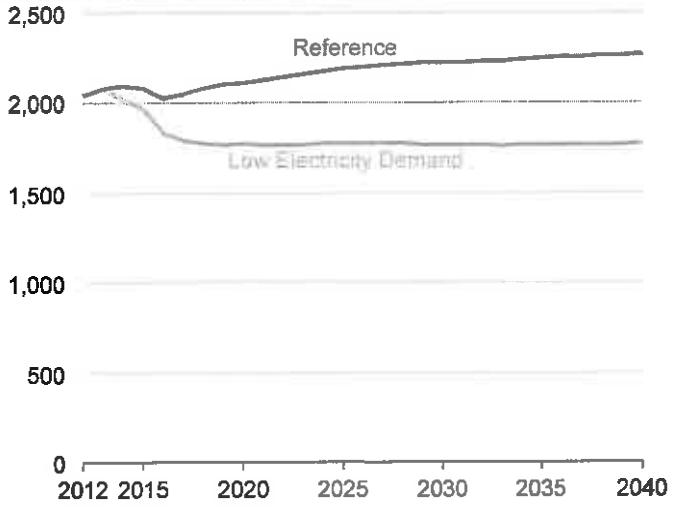
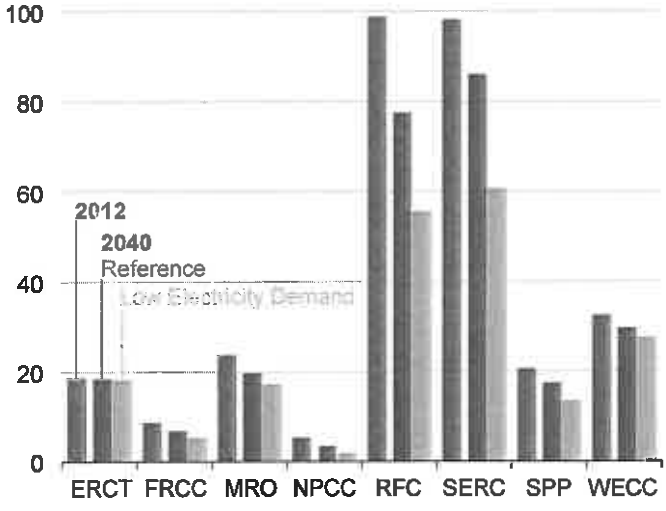



Figure IF8-7. Coal-fired generating capacity by NERC region in two cases, 2012 and 2040 (gigawatts)



## Endnotes for IF8

**Links current as of April 2014**

1. See Appendix F for a map of the Electricity Market Model (EMM) regions. For this discussion, results at the EMM level have been aggregated to the larger NERC regions on which they are based.

## Figure sources for IF8

**Links current as of April 2014**

**Figure IF8-1. Annual changes in U.S. electricity demand, 1950-2012:** U.S. Energy Information Administration, *Monthly Energy Review September 2013*, DOE/EIA-0035 (2013/09) (Washington, DC, September 2013).

**Figure IF8-2. U.S. total electricity demand by sector in two cases, 2012 and 2040: History:** U.S. Energy Information Administration, *Monthly Energy Review September 2013*, DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A and FLAT.D010914A.

**Figure IF8-3. Electricity capacity additions by fuel type in two cases, 2013-40: Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A and FLAT.D010914A.

**Figure IF8-4. Electric power sector cumulative retirements in two cases, 2013-40: Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A and FLAT.D010914A.

**Figure IF8-5. Electricity generation in two cases, 2012-40: History:** U.S. Energy Information Administration, *Monthly Energy Review September 2013*, DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A and FLAT.D010914A.

**Figure IF8-6. Carbon dioxide emissions in the electric power sector in two cases, 2012-40: History:** U.S. Energy Information Administration, *Monthly Energy Review September 2013*, DOE/EIA-0035 (2013/09) (Washington, DC, September 2013). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A and FLAT.D010914A.

**Figure IF8-7. Coal-fired generating capacity by NERC region in two cases, 2012 and 2040: History:** U.S. Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). **Projections:** AEO2014 National Energy Modeling System, runs REF2014.D102413A and FLAT.D010914A.

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# Market trends

Projections by the U.S. Energy Information Administration (EIA) are not statements of what will happen but of what might happen, given the assumptions and methodologies used for any particular case. The Reference case projection is a business-as-usual estimate, given known market, demographic, and technological trends. Most cases in the *Annual Energy Outlook 2014* (AEO2014) generally assume that current laws and regulations are maintained throughout the projections. Such projections provide a baseline starting point that can be used to analyze policy initiatives. EIA explores the impacts of alternative assumptions in other cases with different macroeconomic growth rates, world oil prices, rates of technological progress, and policy changes.

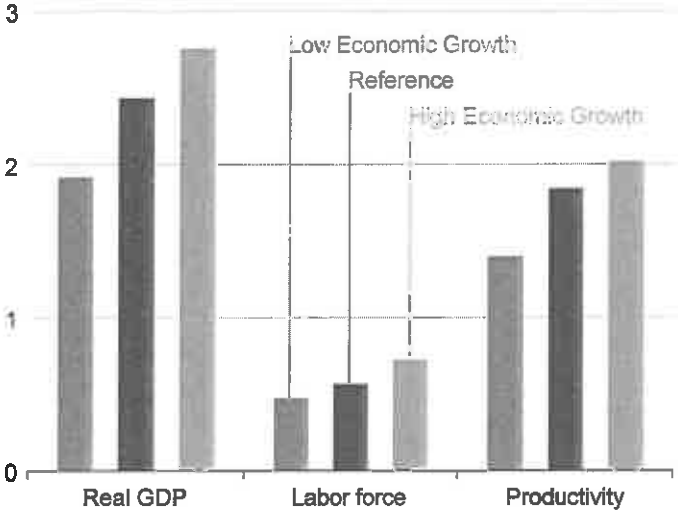
While energy markets are complex, energy models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics 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. Many key uncertainties in the AEO2014 projections are addressed through alternative cases.

EIA has tried to make these projections as objective, reliable, and useful as possible. However, they should serve as an adjunct to, not as a substitute for, a complete and focused analysis of public policy initiatives.

## Growth in business fixed investment offsets slow growth in labor force

Figure MT-1. Average annual growth rates of real GDP, labor force, and productivity in three cases, 2012-40 (percent per year)



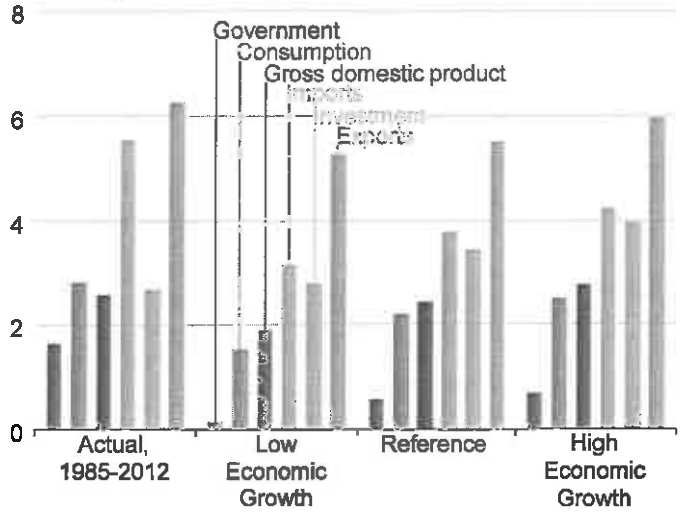

Growth in the output of the U.S. economy depends on increases in the labor force, growth of capital stock, and improvements in productivity. In the *Annual Energy Outlook 2014* (AEO2014) Reference case, U.S. labor force growth slows over the projection period as the baby boom generation starts to retire, but projected growth in business fixed investment and spending on research and development offsets the slowdown in labor force growth. Annual growth in real gross domestic product (GDP) averages 2.4%/year from 2012 to 2040 in the Reference case (Figure MT-1), 0.3 percentage point slower than the growth rate over the past 30 years. Slow long-run increases in the labor force indicate more moderate long-run employment growth, with total civilian employment rising by an average of 0.8%/year, from 134 million in 2012 to 169 million in 2040. The manufacturing share of total employment continues to decline, from 9% in 2012 to 7% in 2040.

Real consumption growth averages 2.2%/year in the Reference case. From 2012 to 2040, the share of GDP accounted for by personal consumption expenditures varies between 66% and 71%, and the share spent on services rises mainly as a result of increasing expenditures on health care. The share of GDP devoted to business fixed investment ranges from 10% to 16% of GDP through 2040.

Issues such as financial market reform, fiscal policies, and financial problems in Europe, among others, will affect both short-run and long-run growth, adding uncertainty to the projections.

## Economic activity varies considerably across the economic growth cases

Figure MT-2. Average annual growth rates for real output and its major components in three cases, 2012-40 (percent per year)



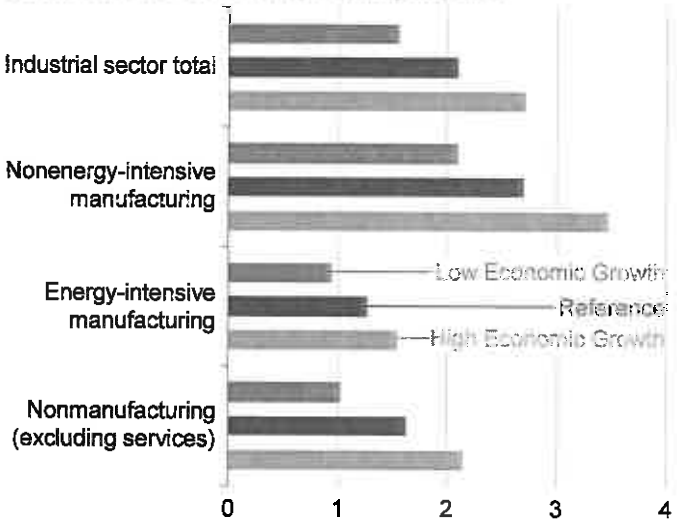

AEO2014 presents three economic growth cases: Reference, High, and Low (Figure MT-2). The High Economic Growth case assumes higher growth and lower inflation, relative to the Reference Case, and the Low Economic Growth case assumes lower growth and higher inflation. The short-term outlook (five years) in each case represents current views of economic activity in the United States and the rest of the world, the impacts of fiscal and monetary policies, and potential risks to economic activity. The long-term outlook includes smooth economic growth and assumes no shocks to the economy.

Differences among the Reference, High, 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 2012 to 2040 in the Reference case is 2.4%, as compared with 2.8% in the High Economic Growth case and 1.9% in the Low Economic Growth case.

Figure MT-2 compares the average annual growth rates for output and its major components in each of the three cases. Compared with the 1985-to-2012 period, investment growth from 2012 to 2040 will be faster in all three cases, whereas consumption, government expenditures, imports, and exports will grow more slowly in all three cases. Opportunities for trade will expand in all three cases, resulting in real trade surpluses that continue to grow throughout the projection period.

## For energy-intensive industries, output growth is strong early, then slows after 2025

Figure MT-3. Average annual growth rates of shipments for the industrial sector and its components in three cases, 2012-40 (percent per year)



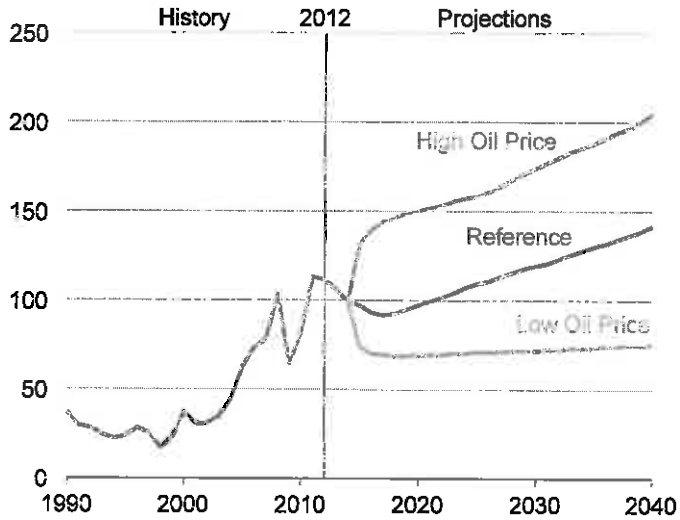

With a rapidly growing service sector and imports meeting a large share of demand for goods in recent decades, industrial sector shipments have expanded more slowly than the overall economy [1]. In the AEO2014 Reference case, real value of shipments for all goods and services [2] grows by 2.0% from 2012 to 2040, for the industrial sector by 2.1%/year, and for the service sector by 2.0%/year. Industrial sector manufacturing grows by 2.3%/year and nonmanufacturing by 1.6%/year (Figure MT-3).

The Reference case shows two distinct periods of growth, and the energy-intensive industries display the sharpest contrast between the periods. With increased shale gas production affecting U.S. competitiveness, growth in U.S. manufacturing output accelerates through 2025. From 2012 to 2025, real GDP grows by an average of 2.5%/year, and the industrial sector grows by 2.8%/year. After 2025, industrial output growth slows as a result of increased foreign competition and rising energy prices, with energy-intensive industries showing the largest slowdowns—from a 2012-25 average of 2.0%/year to a 2025-40 average of 0.7%/year. The 2012-40 output growth rates vary among industries, with iron and steel averaging 0.9%/year and the cement industry 2.5%/year.

Industrial production growth is strongly linked to exports, along with consumer demand and investment. Declining exchange rates, combined with modest escalation in unit labor costs, increase U.S. exports in the projection. From 2012 to 2040, real exports of goods and services increase by an average of 5.5%/year, while real imports of goods and services grow by an average of 3.8%/year.

## Range of oil price cases represents uncertainty in world oil markets

Figure MT-4. North Sea Brent crude oil spot prices in three cases, 1990-2040 (2012 dollars per barrel)



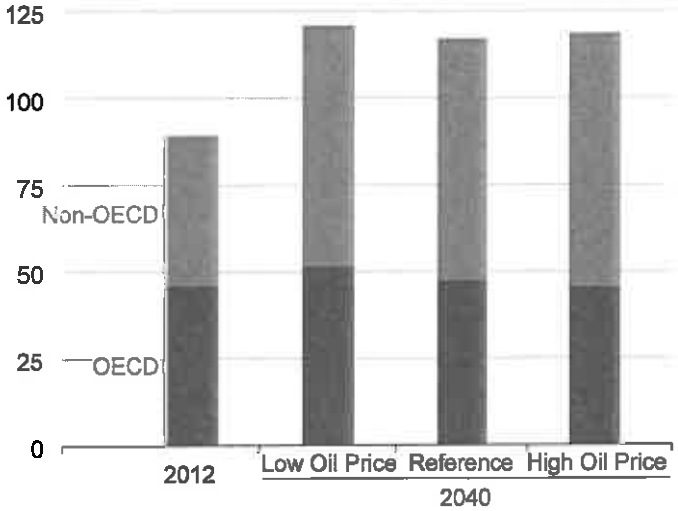

In AEO2014 the North Sea Brent crude oil price is tracked as the main benchmark for world oil prices. In 2013, the West Texas Intermediate (WTI) crude oil price continued to trade at a discount relative to other world oil prices. With refineries running at high levels through August 2013, the discount narrowed as a result of new oil transportation infrastructure from the market center for WTI prices in Cushing, Oklahoma. The discount widened from September to December 2013, however, as lower 48 production continued to grow and refinery utilization returned to lower levels after the summer.

EIA developed three oil price cases—Reference, High, and Low—to examine how alternative price paths could affect energy markets (Figure MT-4). The AEO2014 price cases included varying assumptions about: (1) investment and production decisions by the Organization of the Petroleum Exporting Countries (OPEC), (2) development of tight oil and bitumen resources in non-OPEC countries (including the United States), and (3) demand growth in China, the Middle East, and other countries outside the Organization for Economic Cooperation and Development (non-OECD countries).

Relative to the Reference case, the Low Oil Price case assumes lower economic growth and thus lower liquids demand from non-OECD regions; and rising production from OPEC countries, which displaces relatively more expensive crude oil from non-OPEC producers. In the Low Oil Price case, OPEC supplies 51% of the world's liquid fuels in 2040, compared with 44% in the Reference case. In the High Oil Price case, assuming stronger demand growth and fewer resources developed in OPEC countries, the non-OECD countries account for 62% of world liquids use in 2040, compared with 60% in the Reference case and 57% in the Low Oil Price case. The OPEC share of world liquids production never exceeds 40% in the High Oil Price case.

## Trends in petroleum and other liquids markets are defined largely by the developing nations

Figure MT-5. World petroleum and other liquids consumption by region in three cases, 2012 and 2040 (million barrels per day)



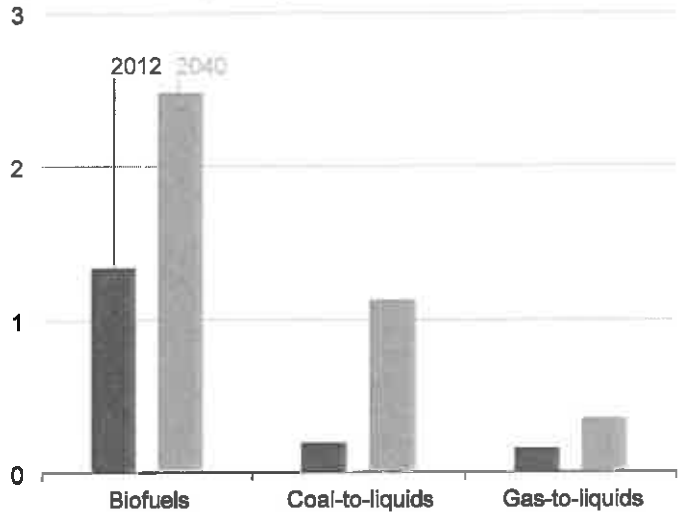

In the AEO2014 Reference, High Oil Price, and Low Oil Price cases, total world consumption of petroleum and other liquids in 2040 ranges from 117 to 121 million barrels per day (MMbbl/d) (Figure MT-5). The alternative oil price cases reflect shifts in both supply and demand. Although demand at the margin in the Organization for Economic Cooperation and Development (OECD) countries is influenced primarily by price, demand in non-OECD regions is driven primarily by rates of economic growth that are particularly uncertain. The AEO2014 High Oil Price case reflects a scenario in which strong economic growth in the emerging non-OECD nations increases the growth of their liquids demand and drives oil prices higher.

OECD petroleum and other liquids use grows in the Reference case to 47 MMbbl/d in 2040, while non-OECD use grows to 70 MMbbl/d. In the High Oil Price case, OECD petroleum and other liquids use in 2040 is lower than in the Reference case, at 45 MMbbl/d, but demand in the fast-growing non-OECD economies rises to 73 MMbbl/d. In the Low Oil Price case, OECD consumption grows to 51 MMbbl/d in 2040, and lower GDP growth in the non-OECD countries leads to slower growth in liquids demand, which reaches only 69 MMbbl/d in 2040. Non-OECD liquids demand would be even lower than projected in the Low Oil Price case, but low oil prices encourage more use of liquid fuels in the non-OECD nations in the long term.

The supply response also varies across the price cases. In the Low Oil Price case, OPEC's ability to manage its market share is weakened. Low prices have a negative impact on non-OPEC petroleum supply in comparison with the Reference case. In the High Oil Price case, OPEC restricts production, non-OPEC petroleum resources become more economical, and high oil prices make production of nonpetroleum liquids more economically attractive.

## World production of liquid fuels from biomass, coal, and natural gas increases

Figure MT-6. World production of nonpetroleum liquids by type in the Reference case, 2012 and 2040 (million barrels per day)




Nonpetroleum liquids are a small but increasing source of total liquids supply in the AEO2014 Reference case. World production of nonpetroleum liquids—including biofuels, coal-to-liquids (CTL), and gas-to-liquids (GTL)—totaled 1.7 MMbbl/d, or 1.9% of total world liquids production, in 2012. In 2040, nonpetroleum liquids production, at 4.0 MMbbl/d, accounts for 3.4% of total world liquids production (Figure MT-6).

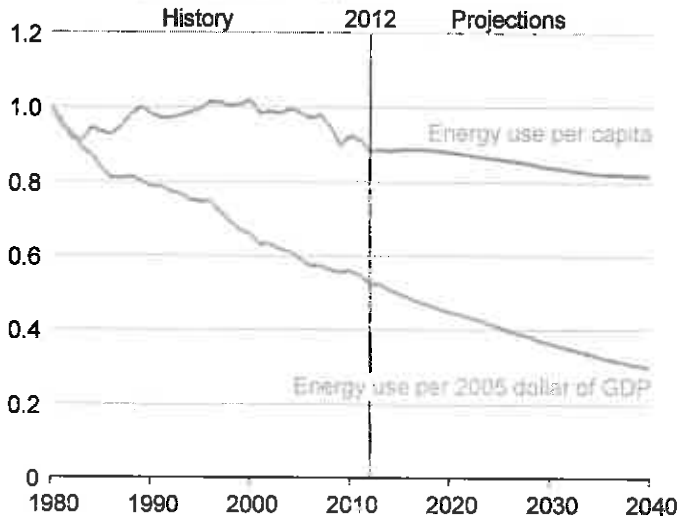
While world production of nonpetroleum liquids is spurred by sustained high prices, high prices alone are not expected to be sufficient to increase U.S. production of nonpetroleum liquids. As a result, no U.S. production of CTL or GTL is projected in the AEO2014 Reference case. U.S. biofuels production does grow in the projection, but only modestly, from 0.9 MMbbl/d in 2012 to 1.1 MMbbl/d in 2040.

The U.S. share of world biofuels production shrinks in the AEO2014 Reference case from 66% in 2012 to 43% in 2040. Biofuels development relies heavily on country-specific programs or mandates and outlooks for transportation fuels. U.S. demand for transportation fuels declines, and without significant additional market penetration of fuels with high-percentage ethanol blends or of drop-in fuels, the possibilities for expanded biofuel production are limited.

Biofuels production accounts for the largest share of total world nonpetroleum liquids production throughout the projection, although its share falls to 63% in 2040 from 79% in 2012. In 2040, world biofuels production of 2.5 MMbbl/d is 68% larger than world production of CTL and GTL combined.

## In the United States, average energy use per person declines from 2012 to 2040

Figure MT-7. Energy use per capita and per dollar of gross domestic product in the Reference case, 1980-2040 (index, 1980 = 1)



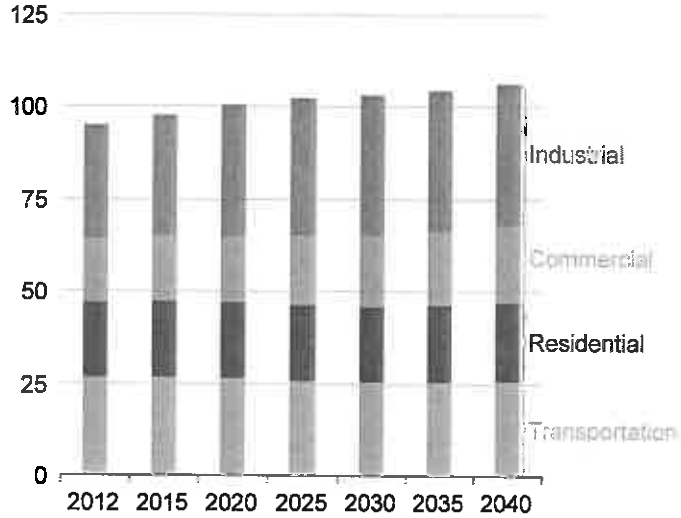

Population growth affects energy use through increases in housing, commercial floorspace, transportation, and economic activity. However, the structure and efficiency of the U.S. economy are changing in ways that can lower energy use. Changes in consumer behavior can also have an impact, such as changes in the rate of vehicle miles traveled (VMT) per licensed driver. U.S. population increases by 0.7%/year from 2012 to 2040; the economy, as measured by gross domestic product (GDP), increases at an average annual rate of 2.4%; and total energy consumption increases by 0.4%/year. As a result, energy intensity, measured both as energy use per person and as energy use per dollar of GDP, declines over the projection period (Figure MT-7).

The projected decline in energy use per capita is brought about largely by gains in appliance efficiency, a shift in production from cooler to warmer regions, and an increase in vehicle efficiency standards, combined with modest growth in travel per licensed driver. From 1970 through 2008, energy use dipped below 320 million British thermal units (Btu) per person for only a few years in the 1980s. In 2012, energy use per capita was about 302 million Btu. In the Reference case, energy use per capita declines to 279 million Btu per person in 2040—a level not seen since 1965.

Continual changes in the structure of the economy reduce energy use per dollar of GDP. Although the service industries' share of total shipments remains below the 2012 level of 78%, the manufacturing sector shifts about 1% of the output from energy-intensive industries to non-energy-intensive industries. Efficiency gains in the electric power sector also reduce overall energy intensity, as older, less-efficient generators are retired as a result of slower growth in electricity demand, changing dispatch economics related to rising fuel prices, and stricter environmental regulations.

## Industrial and commercial sectors lead U.S. growth in primary energy use

Figure MT-8. Primary energy use by end-use sector in selected years in the Reference case, 2012-40 (quadrillion Btu)




Total primary energy consumption, including fuels for electricity generation, grows by 0.4%/year in the Reference case, to 106.3 quadrillion Btu in 2040 (Figure MT-8). The largest increase, 7.8 quadrillion Btu, is in the industrial sector, with increased use of natural gas in some industries (bulk chemicals, for example) as a result of low natural gas prices coinciding with rising shipments in those industries. In the industrial sector, which was more severely affected than the other end-use sectors by the 2007-09 economic downturn, energy consumption increases by 7.0 quadrillion Btu from 2008 to 2040.

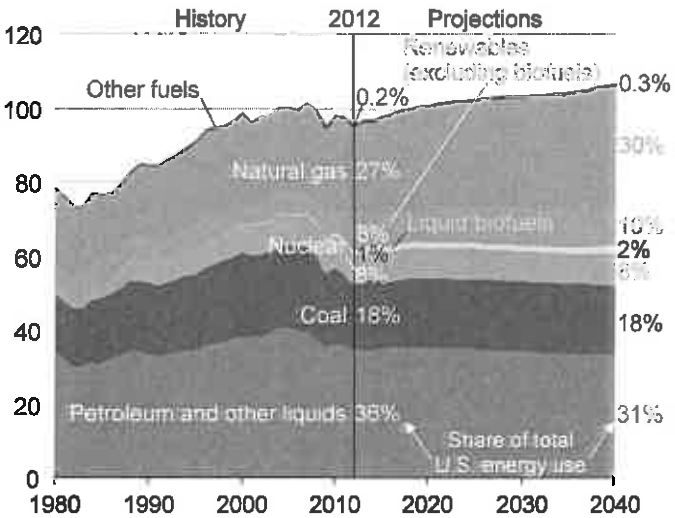
The second-largest increase in total primary energy use, 3.3 quadrillion Btu from 2012 to 2040, is in the commercial sector. Even as standards for building shells and energy efficiency are tightened and commercial energy intensity (energy use per square foot) decreases by 0.4%/year from 2012 through 2040, energy use grows by 0.6%/year as annual growth in commercial floorspace averages 1.0%.

Primary energy use in the residential sector grows by 0.2%/year, or about 1.4 quadrillion Btu from 2012 to 2040. Energy use for space heating was down by almost 1 quadrillion Btu in 2012 because of an unusually warm heating season. In 2040, residential energy use is at 2011 levels, despite reduced energy use for space heating, lighting, and clothes washers, among other uses.

In the transportation sector, light-duty vehicle (LDV) energy use declines with the implementation of fuel economy standards. VMT remain flat (about 12,200 per licensed driver) in the near term, then begin to increase after 2025. From 2012 to 2040, total transportation sector energy use falls by more than 1 quadrillion Btu.

## Renewables and natural gas lead rise in primary energy consumption

Figure MT-9. Primary energy use by fuel in the Reference case, 1980-2040 (quadrillion Btu)




The fossil fuel share of total energy use declines from 82% in 2012 to 80% in 2040 in the Reference case, while renewable energy use grows (Figure MT-9). The renewable share of total energy use (including biofuels) increases from 9% in 2012 to 12% in 2040 in response to the availability of federal tax credits for renewable electricity generation and capacity during the early years of the projection and in response to state renewable portfolio standard (RPS) programs. Biofuel use mandated by the Renewable Fuels Standard (RFS) accounts for a small part of the increase.

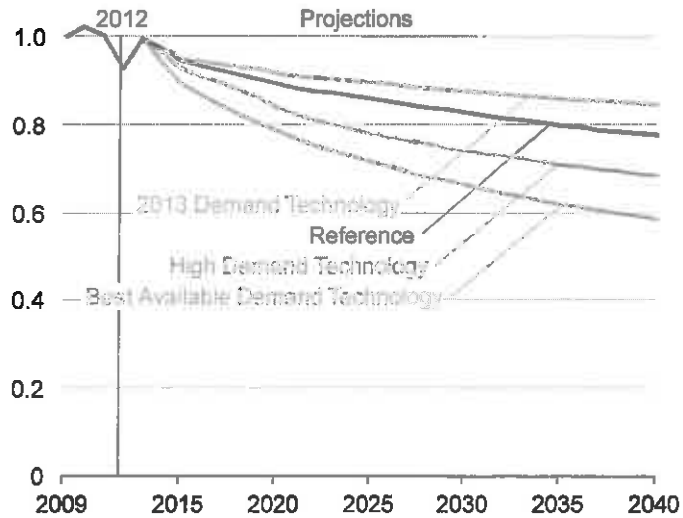
Natural gas consumption grows by about 0.8%/year from 2012 to 2040, led by increases in natural gas use for electricity generation and in the industrial sector. Growing production from tight shale keeps the price of natural gas to end users below 2005-08 levels through 2038.

Increases in vehicle fuel economy offset growth in transportation activity, resulting in a decline in the petroleum and other liquids share of fuel use while consumption of liquid biofuels increases. Biofuels, including E85, biodiesel blended into diesel, and ethanol blended into motor gasoline (up to 15%), account for 4% of all petroleum and other liquids consumption by energy content in 2040.

Coal consumption increases by an average of 0.3%/year from 2012 to 2040, remaining between the 2011 and 2012 levels through 2040. A small amount of coal-fired power plant capacity is added: a total of 2.2 gigawatts (GW) currently under construction and another 0.5 GW added after 2016 (including 0.3 GW with carbon sequestration capability). Coal-fired capacity retirements total 51 GW between 2012 and 2040, but the remaining coal-fired plants continue to be used extensively.

## Residential energy intensity drops across a wide range of technology assumptions

Figure MT-10. Residential delivered energy intensity in four cases, 2009-40 (index, 2009 = 1)



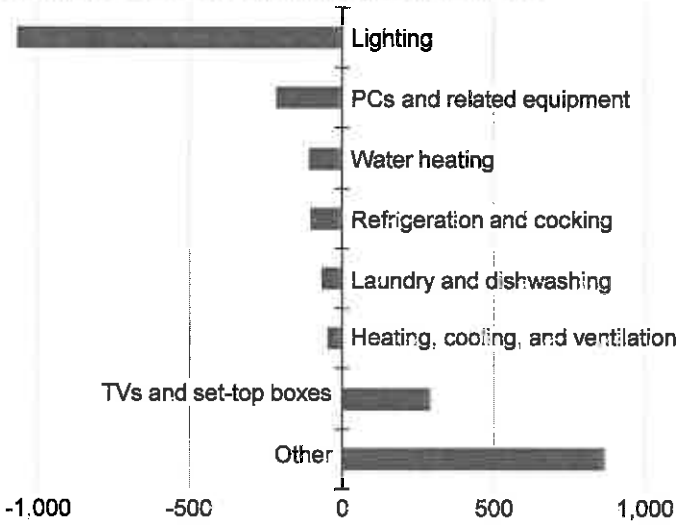

In the AEO2014 Reference case, the intensity of residential energy demand, defined as annual energy use per household, declines by 16% between 2012 and 2040 (Figure MT-10). Energy use for lighting, space heating, and water heating accounts for most of the decline. While household energy intensity decreases, total delivered energy consumption in the residential sector increases by about 5%, with the number of homes growing by 26% over the period. More use of distributed generation, such as from rooftop solar panels, would further reduce delivered energy intensity, but it is not projected to have a large effect, because electricity from distributed generation sources accounts for a small percentage of total electricity use in households over the projection period.

Three additional cases show the effects of different technology assumptions on residential energy intensity. The Best Available Demand Technology case limits purchases of new and replacement equipment by consumers to the most efficient models available at the time of purchase and assumes that the most energy-efficient specifications will be used in new home construction, which influences space heating and cooling demand. The High Demand Technology case assumes higher efficiency, earlier availability, lower cost, and more frequent energy-efficient purchases for some equipment than the Reference case. The 2013 Demand Technology case assumes no future improvement in efficiency for equipment or building shells beyond what is available in 2013.

From 2012 to 2040, household energy intensity declines by 37% in the Best Available Demand Technology case and by 26% in the High Demand Technology case. In the 2013 Demand Technology case, energy intensity is higher than in the Reference case but still declines by 9% from 2012 to 2040 as older, less-efficient appliances are replaced over time by 2013-vintage equipment.

## Electricity use per household declines from 2012 to 2040 in the Reference case

Figure MT-11. Change in residential electricity consumption for selected end uses in the Reference case, 2012-40 (kilowatthours per household)



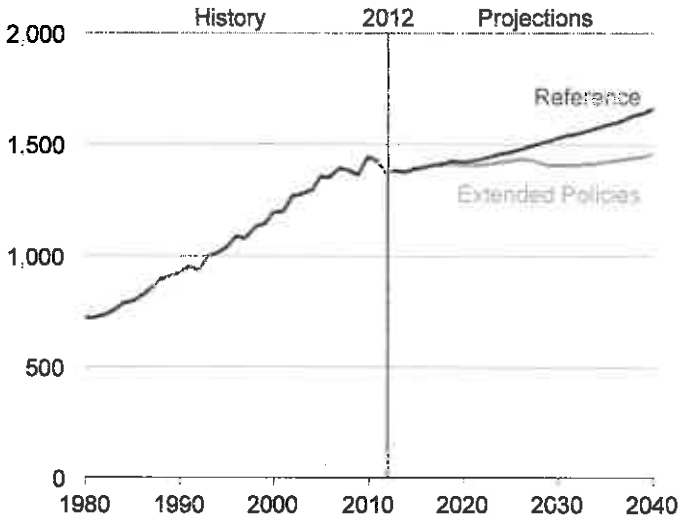

Annual electricity demand for the average household in the Reference case declines by 4%, from 12.1 megawatthours (MWh) in 2012 to 11.6 MWh in 2040. In 2012, the largest uses of electricity at the household level are space cooling, small devices and other minor electric end uses, and lighting. In 2040, electricity consumed for lighting per household is 65% lower, and electricity use for minor electric end uses and for space cooling rises by 33% and 17%, respectively (Figure MT-11). Regulations implementing lighting efficiency standards established by the Energy Independence and Security Act of 2007 (EISA2007) are a major factor in the replacement of incandescent bulbs with more efficient compact fluorescent lighting (CFL) and light-emitting diode (LED) lamps.

Although electricity consumption for most end uses declines on a per-household basis between 2012 and 2040, electricity consumption at the sectoral level increases for most end uses because of growth in the number of households. Most of the growth at the sectoral level comes from increasing market penetration of smaller electric devices, which have little coverage by efficiency standards, and by a growing need for cooling as the U.S. population shifts to warmer climates in the South.

From 2012 to 2040, residential electricity use grows by 21% as the fuel mix in the residential sector moves increasingly toward electricity. Petroleum and other liquids lose fuel share for every end-use service, and particularly for space heating, where both electricity and natural gas gain share. Natural gas loses fuel share in every end-use service except space heating, and it continues to account for more than half of the fuel consumed for space heating, water heating, and cooking through the projection. In 2040, overall natural gas use in the residential sector is 1% lower, and petroleum and other liquids use is 35% lower than in 2012.

## Continuing efficiency gains restrain growth in residential electricity use

Figure MT-12. Residential electricity sales in two cases, 1980-2040 (billion kilowatthours)



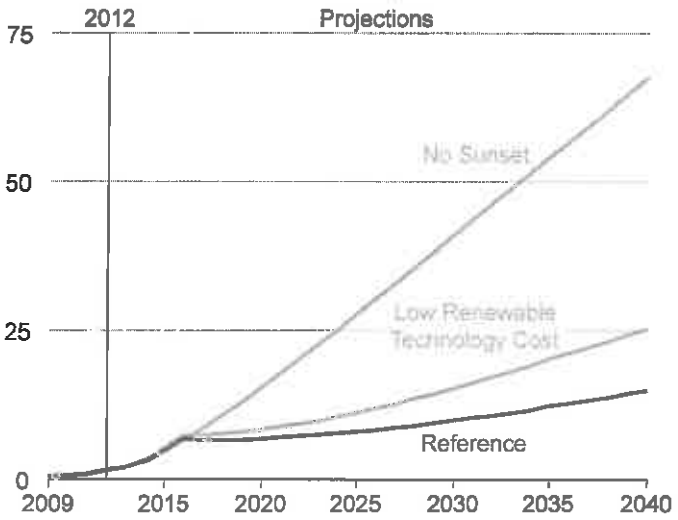

In the AEO2014 Reference case, electricity is the only fuel for which demand increases in the residential sector from 2012 to 2040, in part as a result of population growth, regional population shifts, and temperature assumptions. Electricity is affected more than other fuels by the increased adoption of new and existing uses. In the Reference case, which includes only existing and announced standards and codes, residential electricity demand grows by 0.7%/year from 2012 to 2040 (Figure MT-12). In the Extended Policies case, which assumes additional rounds of appliance standards and building codes in the future, residential electricity use increases by 0.2%/year from 2012 to 2040. In contrast, residential electricity demand grew by an average of more than 2%/year over the previous 30 years.

Most of the announced standards in the Reference case are scheduled to take effect in the near term. For instance, the Reference case includes changes in minimum efficiency levels for refrigerators and freezers in 2014 and for central air conditioners, air source heat pumps, and electric water heaters in 2015. The most distant standard assumed in the Reference case is the 2020 standard for general service lighting, which is a part of the second wave of congressionally-mandated standards from EISA2007.

Given the long lifetimes of most major residential equipment (10 to 30 years), it can take years for an appliance standard to affect the majority of installed equipment; but once the standard has been fully incorporated, electricity consumption tends to increase in line with the growth of housing stock (0.8%/year from 2012 to 2040)—as occurs around 2020 in the Reference case but not until 2035 in the Extended Policies case.

## Extending tax credits supports increased residential use of renewable energy sources

Figure MT-13. Residential distributed generation capacity in three cases, 2009–40 (gigawatts)




Electricity generation capacity from residential solar photovoltaic (PV) and wind technologies roughly doubled from 2010 to 2012. In the AEO2014 Reference case, it doubles again in both 2014 and 2016 before slowing considerably as a result of the planned expiration of the investment tax credit (ITC) after 2016. Without the tax credit available, almost two decades pass before annual additions to residential distributed generation capacity surpass 0.5 gigawatts (GW), as they have in recent years.

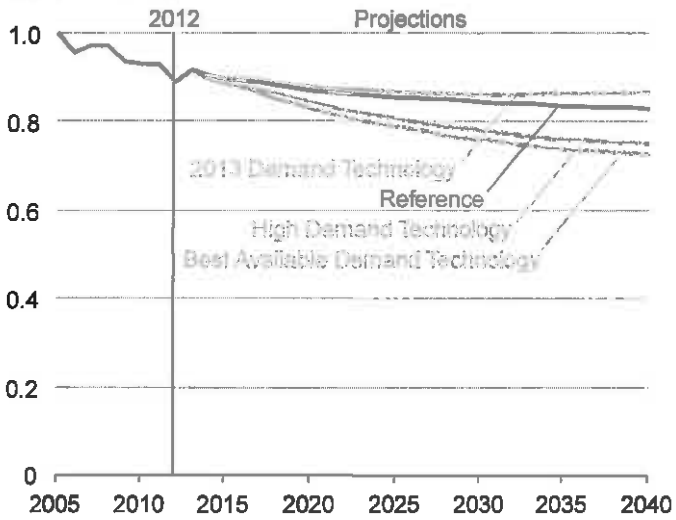
Two alternative cases present more optimistic scenarios for further growth in residential distributed generation, either by extending the tax credits or by lowering installed costs. With the ITC extended beyond its legislated 2016 expiration date in the No Sunset case, residential renewable capacity doubles twice from 2013 to 2019, again from 2019 to 2024, and again from 2024 to 2034. In 2040, more than 67 GW of solar and wind capacity is installed in the residential sector, as compared with less than 2 GW in 2012 (Figure MT-13).

The Low Renewable Technology Cost case includes the tax credit through 2016, as in the Reference case, but assumes lower installed costs than in the Reference case. Even in the Reference case, installed costs for renewable technologies decline from their present values. For example, solar PV installed costs fall from around $5,400 per kilowatt (kW) in 2012 to around $3,270 per kW in 2020 and around $2,900 per kW in 2040.

The Low Renewable Technology Cost case assumes an additional 20% reduction in installed costs after 2013, resulting in increased adoption of both solar PV and wind technologies for electricity generation, especially in locations with the combination of high electricity prices and sufficient renewable resources. By 2040, more than 25 GW of renewable capacity is installed, 10 GW more than in the Reference case.

## Commercial sector energy intensity varies with technology improvements

Figure MT-14. Commercial delivered energy intensity in four cases, 2005–40 (index of energy use per square foot, 2005 = 1)



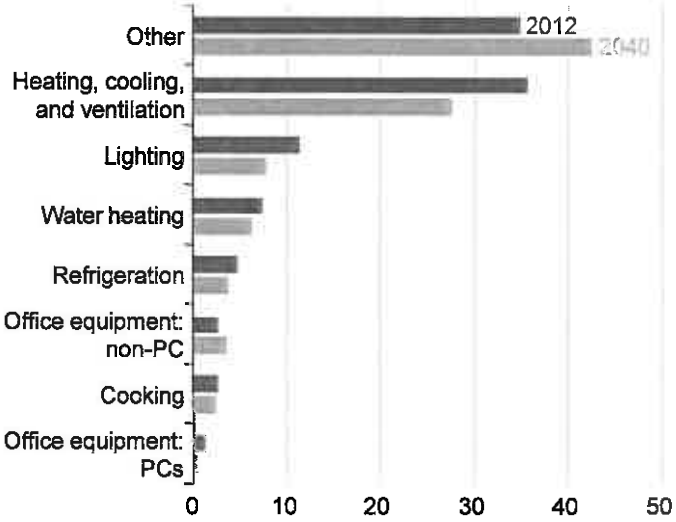

In the AEO2014 Reference case, commercial sector energy intensity, or delivered energy consumption per square foot of commercial floorspace, declines by an average of 0.3%/year from 2012 to 2040 (Figure MT-14). During this period, delivered electricity consumption grows by 0.7%/year despite 1.0% annual growth in commercial floorspace. Natural gas consumption also increases over the period despite increases in building shells and equipment efficiency.

Improvements in major end-use equipment and distributed generation technologies help to slow the growth of delivered energy consumption in the commercial sector. Varying the rate of improvement in the 2013 Demand Technology, High Demand Technology, and Best Available Demand Technology cases shows a range in which equipment and building shell efficiency improvement, or lack thereof, could affect commercial energy consumption.

In the 2013 Demand Technology case, which restricts equipment and shell efficiencies to those available in 2013, energy intensity is reduced by 2.7% from 2012 to 2040, averaging 0.1%/year as equipment is replaced over time and as new buildings are constructed. In the High Demand Technology case, which assumes lower costs and higher efficiencies for commercial equipment and building shells and a 7% real discount rate, commercial energy intensity falls by 0.6%/year, or twice the rate in the Reference case. As a result, energy intensity is 15.8% lower in 2040 than in 2012. The Best Available Demand Technology case allows for even greater shell efficiency improvements than the High Demand Technology case, and also limits future technology choices to only the most efficient models of equipment in each year. As a result, commercial sector energy intensity declines by 0.7%/year on average, to 18.5% below the 2012 level in 2040.

## Energy use continues to shift from personal computing equipment to networked computing

Figure MT-15. Energy intensity of selected commercial end uses in the Reference case, 2012 and 2040 (thousand Btu per square foot)




Commercial energy intensity—the ratio of energy consumption to floorspace—decreases from 2012 to 2040 for most electric end uses in the Reference case, while commercial floorspace increases by 1.0% annually (Figure MT-15). Electricity accounted for 54.5% of commercial delivered energy use in 2012.

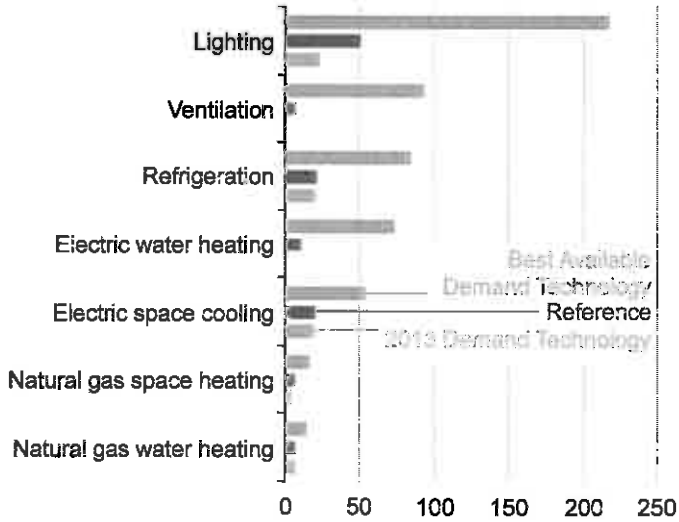
Electricity use for personal computers (PCs), including desktop and laptop computers and monitors, continues to decline. Reductions in processor power use, improvements in display backlighting, and a general shift from desktop to mobile computing devices all cause the energy consumption of PC office equipment to fall by 5.6% annually. With expanding use of web-based services increasing the role of servers in data centers, electricity use by non-PC office equipment grows by 2.0%/year in the Reference case.

Federal efficiency standards moderate energy consumption by major end-use equipment, such as space heating and cooling, water heating, lighting, and refrigeration. The Energy Independence and Security Act of 2007 (EISA2007) mandatory efficacy improvements for lighting continue to foster the adoption of advanced incandescent, fluorescent, and solid-state lighting technologies. As a result, the share of purchased electricity consumption used for lighting declines from 20.7% in 2012 to 14.7% in 2040.

The growing use of energy for miscellaneous electric loads, many of which are not currently subject to federal standards, leads to a 21.4% increase in energy intensity from 2012 to 2040 for other end uses in the Reference case. Miscellaneous electric loads in the commercial sector include medical equipment, video displays, and many other devices. Increases in the use of such devices and equipment can vary greatly by building type and service demand.

## Efficiency gains for advanced technologies reduce commercial energy consumption growth

Figure MT-16. Efficiency gains for selected commercial equipment in three cases, 2040 (percent change from 2012 installed stock efficiency)



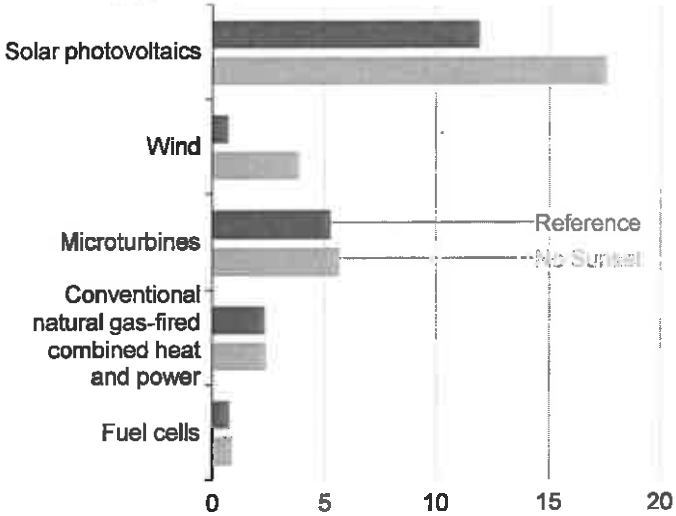

Behind the 0.3% average annual decline in delivered energy intensity in the commercial sector in the AEO2014 Reference case is a shift in the mix of end-use services, from core building services (space heating, space cooling, ventilation, water heating, lighting, cooking, and refrigeration) to other office equipment and electric services. Core end-use energy intensity falls by 0.9%/year from 2012 to 2040, and the intensity of other end uses increases by 0.6%/year on average.

The largest energy efficiency improvements in the Reference case are for lighting, as a result of new standards and the penetration of LED technologies. PC office equipment is a close second to lighting, as a result of the shift toward network computing. Refrigeration, electric space cooling, and electric water heating also show significant efficiency gains (Figure MT-16).

The Best Available Demand Technology case demonstrates significant potential for further improvements—especially for electric equipment in the core end uses. In this case, core end-use intensity declines at more than twice the rate of the Reference case, and core delivered energy use in 2040 is 1.3 quadrillion Btu lower than in the Reference case. Lighting accounts for 35% of the additional delivered energy savings, resulting from both earlier and more widespread penetration of LED technologies than in the Reference case. Beyond lighting, the Best Available Technology case projects significant savings for variable air volume ventilation systems, high-efficiency chiller systems for space cooling, high-efficiency natural gas furnaces, and various advanced refrigeration technologies. Together with lighting, those end uses account for more than 90% of the energy savings relative to the Reference case, with delivered energy consumption in 2040 only 0.6 quadrillion Btu higher than in 2012 and delivered energy intensity declining by 0.7%/year.

## Renewable technologies drive more additions to distributed generation capacity

Figure MT-17. Additions to electricity generation capacity in the commercial sector in two cases, 2012-40 (gigawatts)



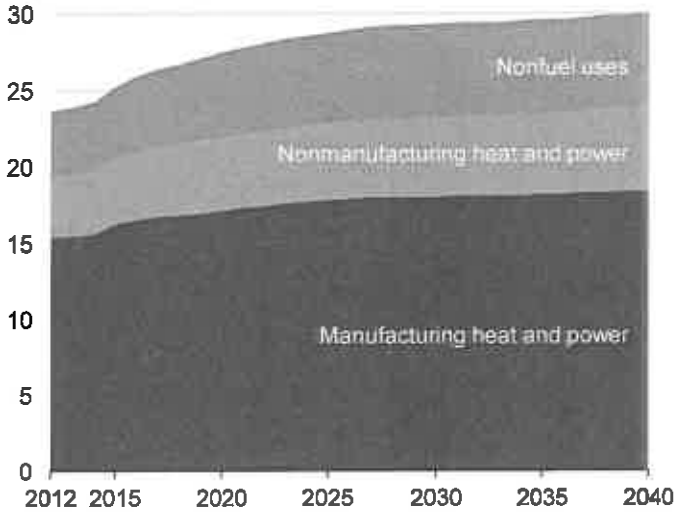

Renewable energy sources, chiefly solar photovoltaic and wind, continue to dominate new commercial distributed generation capacity in the AEO2014 Reference case, accounting for 62.3% of commercial capacity in 2040. Lower prices for photovoltaic inverters and panels, decreasing installation costs, federal investment tax credits, and state and utility rebates all contribute to growth in commercial photovoltaic capacity, which increases by 5.7%/year from 2012 to 2040 in the Reference case. The current 30% federal investment tax credit continues through 2016, after which it reverts to 10%. In the No Sunset case, with investment tax credits for all distributed generation technologies extended through 2040, photovoltaic capacity increases by an average of 7.0%/year.

Small-scale wind capacity grows by 14.2%/year from 2012 to 2040 in the No Sunset case, compared with 7.9%/year in the Reference case (Figure MT-17). As in the case of solar photovoltaic, additional federal and local incentives help to support the growth in commercial wind capacity. Commercial wind capacity accounts for 11.1% of the 35.7 gigawatts (GW) of total distributed generation capacity in 2040 in the No Sunset case, with photovoltaic capacity accounting for 58.1%.

Rising fuel prices offset the effects of the 10% investment tax credit on nonrenewable technologies for distributed generation. In the Reference case, microturbine capacity using natural gas grows by 15.3%/year on average, from 98.3 MW in 2012 to 5.4 GW in 2040, and its growth rate in the No Sunset case is only slightly higher, at 15.7%/year. The microturbine share of total distributed generation capacity in 2040 is 16.2% in the No Sunset case, compared with 20.4% in the Reference case. Fuel cell capacity grows by an average of 12.3%/year in the Reference case and 12.7%/year in the No Sunset case.

## Growth in industrial energy consumption is slower than growth in shipments

Figure MT-18. Industrial energy consumption by application in the Reference case, 2012-40 (quadrillion Btu)



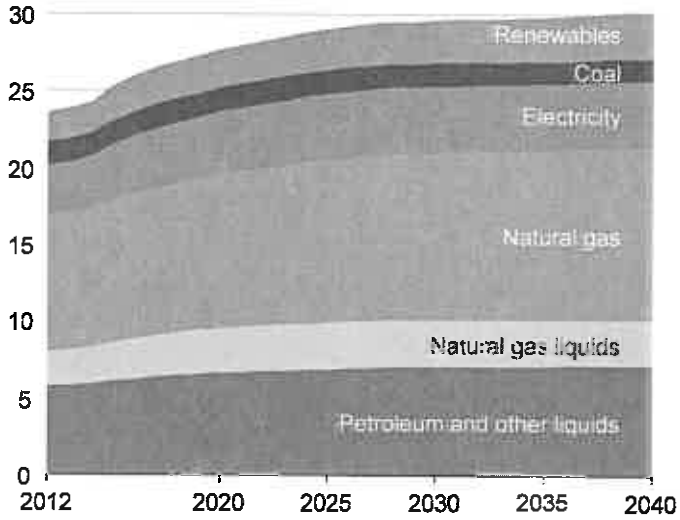

In the AEO2014 Reference case, manufacturing shipments increase by 87% from 2012 to 2040, while delivered energy consumption for heat and power in the manufacturing sector increases by only 19%. The continued decline in energy intensity of manufacturing is explained in part by continued improvement in the efficiency of industrial equipment as energy prices gradually increase, and by a shift in the share of shipments from energy-intensive manufacturing industries to non-energy-intensive industries. With growing foreign competition, shipments and energy use in many trade-exposed energy-intensive industries (bulk chemicals, petroleum refineries, iron and steel, and aluminum) begin declining around 2025. For less energy-intensive manufacturing industries (plastics, computers, machinery, and transportation), shipments continue to grow, capturing a larger share of total U.S. manufacturing output.

In the nonmanufacturing industries (agriculture, mining, and construction), energy intensity declines from 2012 to 2040, as shipments increase by 57% and as total delivered energy consumption increases by 41%. The decline in energy intensity is limited by the mining industry, where energy intensity increases as resource extraction moves into less productive areas.

U.S. manufacturing energy consumption for heat and power grows in the Reference case by an average of 1.1%/year from 2012 to 2025, and then slows to 0.2%/year from 2025 to 2040 (Figure MT-18). Nonmanufacturing energy consumption grows by an average of 1.9%/year from 2012 to 2025, and then slows to 0.6%/year from 2025 to 2040. Nonfuel energy use, principally bulk chemical feedstocks and asphalt, grows robustly at 2.6% annually from 2012 to 2025, largely as a result of rising bulk chemical shipments. After 2025, nonfuel energy use increases 0.1%/year, in parallel with bulk chemical shipments.

## Reliance on natural gas, natural gas liquids, and renewables rises as industrial energy use grows

Figure MT-19. Industrial energy consumption by fuel in the Reference case, 2012–40 (quadrillion Btu)




Total delivered energy consumption in the industrial sector increases by 28% (6.6 quadrillion British thermal units [Btu]) from 2012 to 2040 in the AEO2014 Reference case (Figure MT-19). Much of the growth is in natural gas use, which accounts for 34% of the total increase in energy consumption from 2012 to 2025 and 59% of the increase from 2025 to 2040, as a result of relatively low natural gas prices from steady increases in domestic natural gas production through 2040. The mix of industrial energy sources stays relatively constant, however, reflecting limited remaining capability for switching from other fuels to natural gas in most industries.

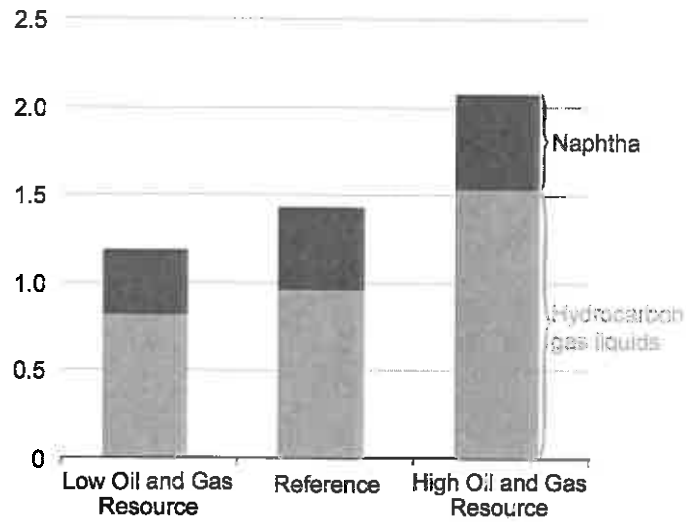
Renewable fuel consumption increases by 53% from 2012 to 2040, although as a percentage of total energy consumption, renewable fuels remain small, at 10% of total energy consumption in 2040. The paper industry remains the predominant user of renewable energy, accounting for roughly 66% of the energy consumed for heat and power in that industry.

Industrial consumption of hydrocarbon gas liquids (HGL) increases by 35% from 2012 to 2025, followed by a 5% decline from 2025 to 2040. HGL are consumed predominantly as feedstocks in the bulk chemicals industry, and smaller amounts (mostly propane) are consumed for process heat in other industries. Coal is the only industrial fuel that shows a consistent decline in consumption, from 6% of the total in 2012 to 5% in 2040.

Low natural gas prices and increased availability of biomass contribute to growth in the use of combined heat and power (CHP). Industrial CHP generation, excluding the refining industry, increases by 88%, from 111.3 billion kilowatthours (kWh) in 2012 to 208.9 billion kWh in 2040.

## Bulk chemicals feedstock mix reflects both relative fuel prices and demand for chemicals

Figure MT-20. Change in liquid feedstock consumption in three cases, 2012–40 (quadrillion Btu)




Liquid feedstock consumption in the bulk chemicals industries is divided between heavy feedstock (petroleum-based naphtha and gasoil) and light feedstock (hydrocarbon gas liquids [HGL], primarily ethane and propane), according to their relative prices. Heavy feedstock prices follow the price of oil, and prices for HGL feedstock, a composite of propane and ethane prices, vary relative to both oil and natural gas prices. Ethane prices are also influenced by production of ethane from natural gas plant liquids and by demand for organic and resin chemicals.

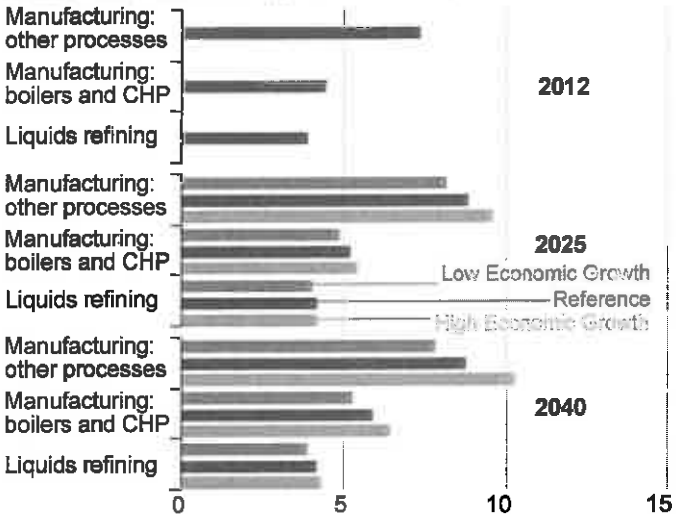
Shipments in the bulk chemicals industries grow by 60% from 2012 to 2028 in the AEO2014 Reference case, followed by no growth after 2028. Growth in total liquid feedstock consumption follows a similar pattern.

In the AEO2014 projections, the mix of feedstocks used to produce bulk chemicals varies with changes in supply assumptions. In the High Oil and Gas Resource case, natural gas prices in 2040 are 40% lower than in the Reference case, while crude oil prices are 12% lower. As a result, the HGL feedstock price in 2040 is 31% lower than in the Reference case, while the heavy feedstock price is only 18% lower. In the Low Oil and Gas Resource case, the HGL feedstock price in 2040 is 13% higher than in the Reference case, while the heavy feedstock price is only 3% higher.

The greater variation in feedstock prices in the High Oil and Gas Resource case leads to more change in the feedstock mix (Figure MT-20), with the use of light HGL feedstock growing faster than the use of heavy naphtha feedstock. In all the cases, consumption of heavy feedstock continues to grow from 2012 to 2040, because some chemicals, such as butadiene and aromatics, cannot be made in sufficient quantities to meet demand by cracking only HGL feedstocks.

## For manufacturing applications, heat and power use varies with economic assumptions

Figure MT-21. Heat and power consumption for refining and manufacturing applications in three cases, 2012, 2025, and 2040 (quadrillion Btu)



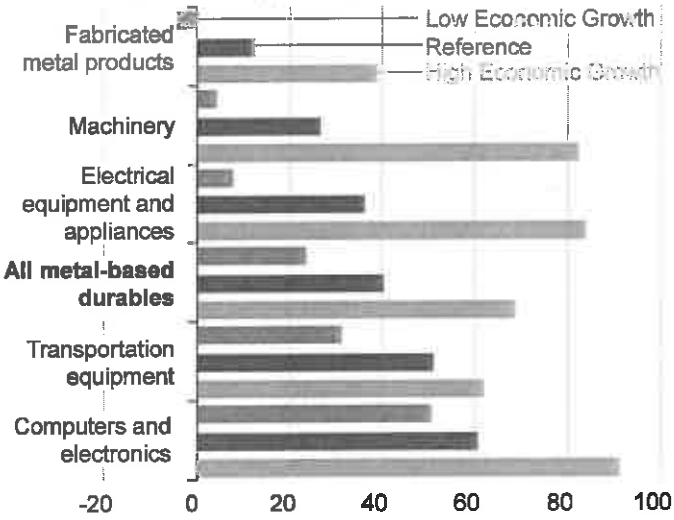

There are three principal uses of energy for heat and power in manufacturing: steam generation for process heat applications, direct-fired heat applications, and the use of electricity to drive machinery. Steam, produced in boilers and by CHP applications, accounted for 4.4 quadrillion Btu of the 14.8 quadrillion Btu of energy consumed for heat and power in the manufacturing sector in 2012. The remaining 10.4 quadrillion Btu of energy consumed for heat and power in manufacturing in 2012, consisting of fuels and purchased electricity, was used in applications such as motors, kilns, direct process heaters, and refining of liquid fuels. Energy for manufacturing can also be used to produce chemical feedstocks.

Demand for heat in the manufacturing sector is particularly sensitive to the rate of economic growth (Figure MT-21). In the Reference case, industrial energy use for boilers and CHP grows by 32% from 2012 to 2040, compared with 45% in the High Economic Growth case and 18% in the Low Economic Growth case.

The energy-intensive manufacturing industries account for a disproportionate amount of the energy used in boiler and CHP applications. The paper industry is the largest industrial user of boiler and CHP, which accounted for 1.6 quadrillion Btu, or roughly 80%, of total heat and power consumption in the paper industry in 2012. The paper industry also recovered 1.2 quadrillion Btu of renewable and waste fuels in 2012, specifically wood, pulping liquor, and municipal solid waste, all of which was consumed in recovery boilers. In addition, roughly half of the energy consumed for heat and power in the bulk chemicals industry in 2012 was used for boiler and CHP applications. Adoption of CHP in energy-intensive industries with stable base-steam demand offers significant potential for energy savings and cost reductions.

## Energy consumption in the metal-based durables industries increases rapidly

Figure MT-22. Cumulative growth in energy consumption by metal-based durables industries in three cases, 2012-40 (percent)




Energy consumption in the metal-based durables industries increases at a rate that is more than twice the rate of growth in the energy-intensive industries, driven by higher growth in shipments relative to the energy-intensive industries. Energy consumption in the metal-based durables industries grows from 1.4 quadrillion Btu in 2012 to 2.0 quadrillion Btu in 2040 in the AEO2014 Reference case, compared with 1.7 quadrillion Btu in 2040 in the Low Economic Growth case and 2.4 quadrillion Btu in 2040 in the High Economic Growth case.

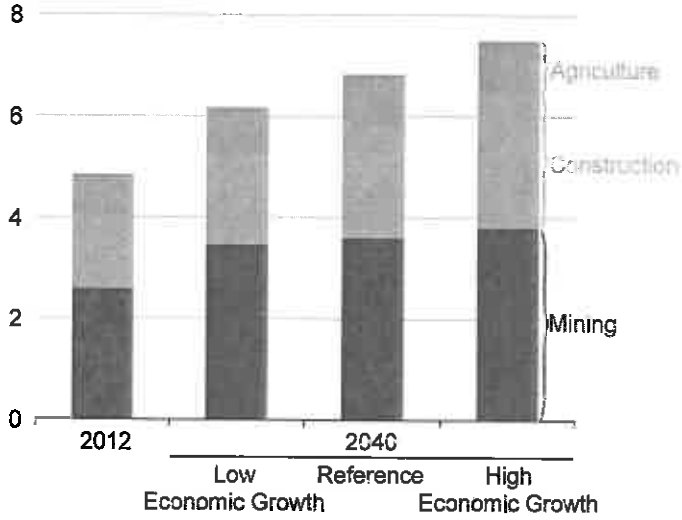
In each of the three cases, the energy intensity of metal-based durables industries declines from 2012 to 2040. Shipments grow more rapidly than energy use, as the industries' energy efficiency improves significantly over the period. Energy intensity in the metal-based durables industries declines by 1.5%/year from 2012 to 2040 in both the Reference and Low Economic Growth cases and by 1.7%/year in the High Economic Growth case.

The mix of energy used in the metal-based durables industries differs significantly from that in the energy-intensive industries. With extensive use of machine drive, the metal-based durables industries use more electricity as a share of total energy consumption. Also, manufacturing in the metal-based durables industries uses energy for facility support activities, such as lighting and climate control.

Growth varies among specific segments of the metal-based durables industries (Figure MT-22). After 2025, shipments and energy use slow significantly in the fabricated metals and machinery segments but only slightly in other segments of the metal-based durables industries. The segment with the fastest growth in shipments and energy use is computers and electronic products.

## Nonmanufacturing energy intensity reductions are tempered by the mining industry

Figure MT-23. Delivered energy consumption by nonmanufacturing industries in three cases, 2012 and 2040 (quadrillion Btu)



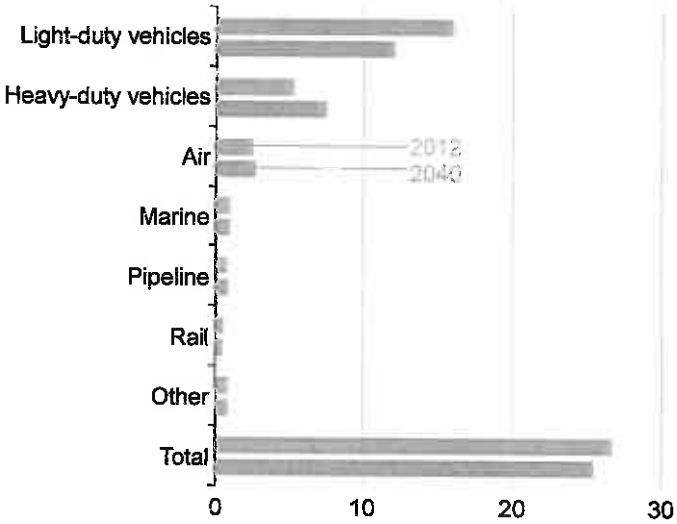

In 2040, nonmanufacturing industries account for $2.6 trillion (2005 dollars) in shipments in the AEO2014 Reference case—a 57% increase from 2012. From 2012 to 2040, total energy consumption in the nonmanufacturing subsector increases by 27% (1.3 quadrillion Btu) in the Low Economic Growth case, 41% (2.0 quadrillion Btu) in the Reference case, and 55% (2.6 quadrillion Btu) in the High Economic Growth case (Figure MT-23).

The nonmanufacturing subsector consists of the construction, agriculture, and mining industries. In the Reference case, it accounts for roughly 23% of total value of shipments and about 23% of total delivered energy consumed in the industrial sector in 2040. The mining industry is the most energy-intensive of the three industries, accounting for 53% of the energy consumed in the nonmanufacturing subsector in 2040 but only 20% of the value of shipments. In contrast, the construction industry accounts for 65% of the shipments in 2040 but only 33% of the energy consumed, and the agriculture sector accounts for 15% of the shipments and 14% of the energy consumed.

Overall, energy intensity declines in the nonmanufacturing subsector by 10% from 2012 to 2040 in the Reference case. Construction and agriculture both show a decline in energy intensity of 17% from 2012 to 2040, whereas the mining industry shows an increase in energy intensity of 26% over the same period. The energy intensity of mining increases as producers move into less-productive areas over time.

## Transportation sector energy consumption declines in the Reference case

Figure MT-24. Delivered energy consumption for transportation by mode in the Reference case, 2012 and 2040 (quadrillion Btu)



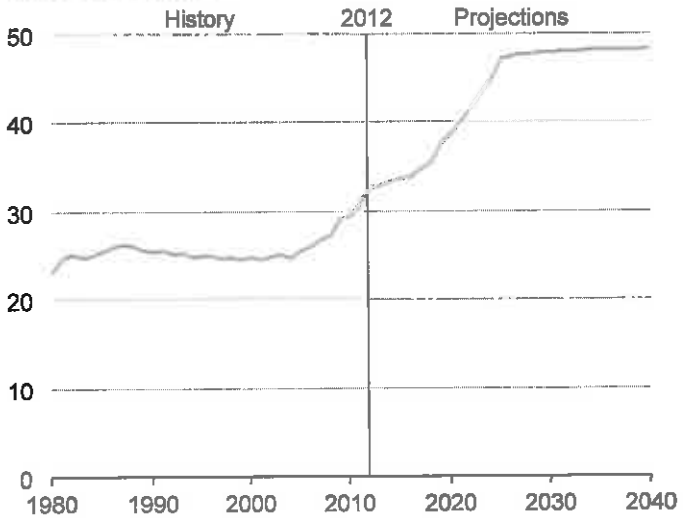

Transportation sector energy consumption declines from 26.7 quadrillion Btu in 2012 to 25.5 quadrillion Btu in 2040 in the AEO2014 Reference case (Figure MT-24), differing markedly from the longer historic trend. Transportation energy consumption grew by an average of 1.3%/year from 1973 to 2007, when it totaled 29.1 quadrillion Btu [3]. The decline in transportation energy demand is the result of significantly less energy use by light-duty vehicles (LDVs), along with a small decline in energy use by rail, which together more than offset increased energy use by heavy-duty vehicles (HDVs), aircraft, marine vessels, and pipelines.

LDV energy demand falls sharply, from 16.0 quadrillion Btu in 2012 to 12.1 quadrillion Btu in 2040, as the result of higher fuel economy that more than offsets increases in LDV travel. Even with new standards for HDV fuel efficiency and greenhouse gas emissions starting in 2014, energy use by HDVs (including tractor trailers, buses, vocational vehicles, and heavy-duty pickup trucks and vans) increases the fastest among the transportation modes, from 5.3 quadrillion Btu in 2012 to 7.5 quadrillion Btu in 2040, as a result of increased demand for travel as economic output grows.

Aircraft energy consumption increases modestly, from 2.5 quadrillion Btu in 2012 to 2.7 quadrillion Btu in 2040, with growth in personal air travel mostly offset by gains in aircraft fuel efficiency. Energy consumption by marine vessels grows as increased international trade boosts demand for shipping and rising incomes increase demand for recreational boating. Pipeline energy use is tempered as increasing volumes of natural gas are produced closer to end-use markets, and energy consumption for rail travel declines slightly as the efficiency of rail improves more rapidly than travel demand increases.

## CAFE and greenhouse gas emissions standards boost light-duty vehicle fuel economy

Figure MT-25. Average fuel economy of new light-duty vehicles in the Reference case, 1980-2040 (miles per gallon)

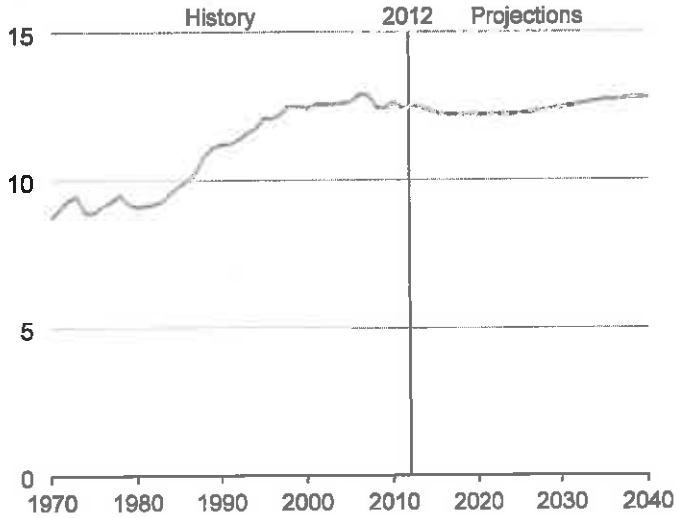



The 1978 introduction of corporate average fuel economy (CAFE) standards for LDVs increased the average fuel economy of these vehicles from 19.9 miles per gallon (mpg) in 1978 to 26.2 mpg in 1987. Despite technology improvements, however, as sales of light trucks increased from 17% of new LDV sales in 1980 to 53% in 2004 [4], fuel economy fell below 26 mpg in 1989 and did not rise above that level until 2007. From 2008 through 2012, LDV average fuel economy rose steadily from 27.1 mpg to 32.7 mpg, as a result of more stringent CAFE standards for light-duty trucks starting in model year 2008 and for passenger cars starting in model year 2011; CAFE and greenhouse gas (GHG) emissions standards for passenger cars and light-duty trucks starting in model year 2012; rising fuel prices; and a reduction in the sales share of light trucks.

The National Highway Traffic Safety Administration (NHTSA) and the U.S. Environmental Protection Agency (EPA) have jointly issued new GHG emissions and CAFE standards for model years 2012 through 2025 [5, 6], which are included in AEO2014. As a result, the fuel economy of new LDVs, measured in terms of their compliance values in CAFE testing [7], rises from 32.7 mpg in 2012 to 47.2 mpg in 2025 (Figure MT-25). The GHG emissions and CAFE standards are held roughly constant after 2025 in the Reference case, but fuel economy continues to rise, to 48.2 mpg in 2040, as new fuel-saving technologies are adopted. In 2040, passenger car fuel economy averages 55.6 mpg, and light-duty truck fuel economy averages 40.9 mpg.

## Miles traveled per licensed driver remains below its historic high through 2040

Figure MT-26. Vehicle miles traveled per licensed driver in the Reference case, 1970-2040 (thousand miles)



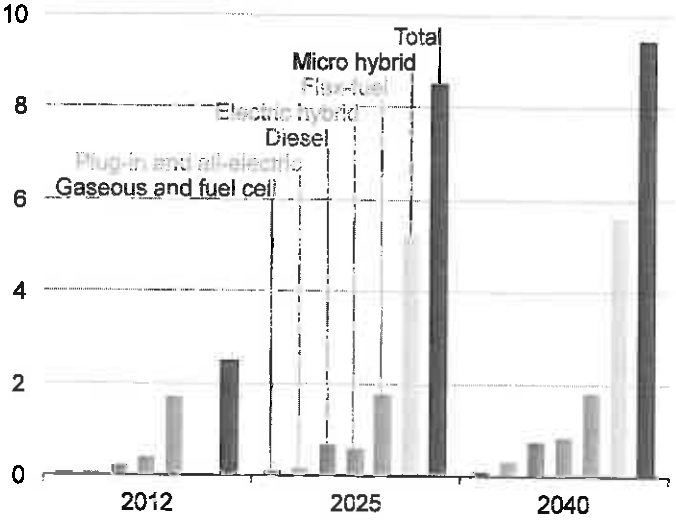

Personal vehicle travel demand, measured as annual vehicle miles traveled (VMT) per licensed driver, declined from its historic high of 12,900 miles in 2007 to about 12,500 miles in 2012. In the AEO2014 Reference case, personal vehicle travel continues declining to 12,200 miles in 2020 before increasing to 12,800 miles in 2040—still below the 2007 level (Figure MT-26). Although motor gasoline prices, personal income, and vehicle fuel efficiency continue to influence personal vehicle travel, the major factors in the decline from 2013 through 2025 are changes in travel patterns by driver age and gender groups and changes in employment rates.

The number of licensed drivers grows by an average of 0.8%/year from 2012 to 2040, but declines in personal vehicle travel demand for some age groups cause an overall decline in VMT per licensed driver. The employment rate of the licensed driver population (the employed, nonfarm population ages 16 and over), which fell by 4 percentage points during the 2007-09 recession, does not rebound to pre-recession levels before 2040, tempering the projected growth in personal travel. Total light-duty VMT increase in the Reference case to 3.4 trillion in 2040—a 29% increase from 2012—as a result of 26% overall growth in the number of licensed drivers, from 213 million in 2012 to 269 million in 2040.

Although vehicle sales also grow through 2040, the number of vehicles per licensed driver drops from 1.12 in 2007 to 1.02 in 2040, limiting the availability of vehicles for travel. Motor gasoline prices fall from 2012 levels and do not exceed that level until 2035, while real personal disposable income per licensed driver increases by 55% through 2040. The changes in travel behavior and demographics more than offset the boost to personal travel provided by income growth and lower motor gasoline prices.

## Sales of vehicles using nongasoline technologies grow by nearly 400 percent from 2012 to 2040

Figure MT-27. Sales of light-duty vehicles using nongasoline technologies by type in the Reference case, 2012, 2025, and 2040 (million vehicles sold)



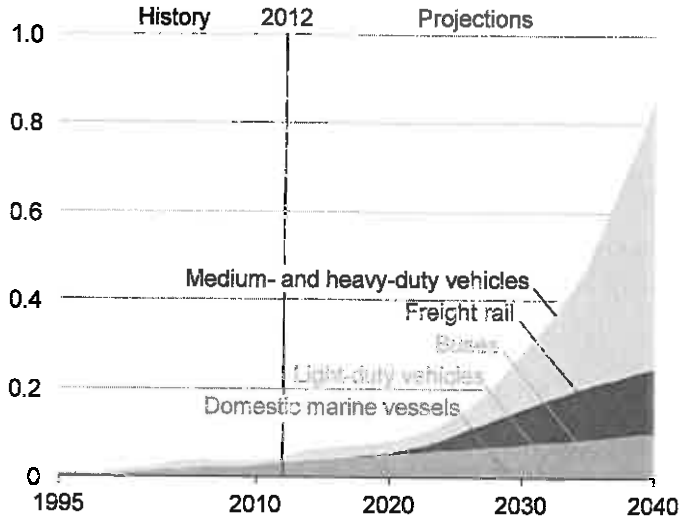

Light-duty vehicles (LDVs) that use diesel, alternative-fuel, hybrid-electric, or all-electric systems play a significant role in meeting more stringent GHG emissions and corporate average fuel economy (CAFE) standards in the AEO2014 Reference case, with sales increasing from 18% of all new LDV sales in 2012 to 55% in 2040. Micro hybrid vehicles, defined here as conventional gasoline vehicles with micro hybrid systems that manage engine operation at idle, represent 33% of new LDV sales in 2040 (Figure MT-27). Flex-fuel vehicles (FFVs), which can use blends of up to 85% ethanol, represent about 11% of all new LDV sales in 2040. Current incentives for manufacturers selling FFVs, which are available in the form of fuel economy credits earned for CAFE compliance, expire at the end of 2019. As a result, the FFV share of LDV sales rises through 2019 and then remains flat through the rest of the projection.

Sales of hybrid electric and all-electric vehicles that use stored electric energy for motive power grow substantially in the Reference case. Gasoline- and diesel-electric hybrid vehicles account for 5% of total LDV sales in 2040. Plug-in hybrid and all-electric vehicles account for 2% of total LDV sales and 3% of total sales of vehicles using diesel, alternative-fuel, hybrid, or all-electric systems.

The diesel vehicle share of total LDV sales remains roughly constant from 2012 to 2040 in the Reference case. Light-duty gaseous and fuel cell vehicles account for less than 1% of new vehicle sales because of limited fueling infrastructure and the high incremental costs of the vehicles.

## Natural gas use for transportation fuel grows but still makes up a modest share of total use

Figure MT-28. Natural gas consumption in the transportation sector in the Reference case, 1995-2040 (quadrillion Btu)



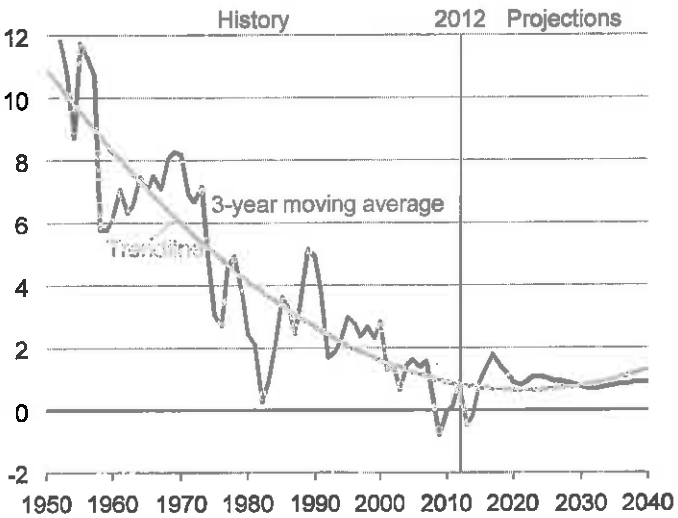

The use of compressed natural gas (CNG) and liquefied natural gas (LNG) in LDVs, HDVs, locomotives, buses, and marine vessels grows from 43 trillion Btu in 2012 to 863 trillion Btu in 2040 in the Reference case (Figure MT-28). Still, CNG and LNG account for only 3% of total energy consumption in the transportation sector in 2040, similar to the amount of natural gas consumed in pipeline transport.

Medium-duty and heavy-duty vehicles—including tractor trailers, vocational vehicles, pickups, and vans with a gross vehicle weight rating (GVWR) of 10,001 pounds or more—become the largest consumers of CNG and LNG, increasing from 11 trillion Btu in 2012 to 613 trillion Btu in 2040 in the Reference case. The increase is spurred by relatively low natural gas prices. Initially, natural gas is consumed primarily by medium-duty trucks using CNG; but the vast majority of growth in natural gas consumption is for heavy-duty trucks (primarily tractor trailers) using LNG—a relatively high-mileage application in which the fuel cost savings of LNG offset the significant incremental capital cost of LNG vehicles.

LNG energy consumption by freight rail locomotives grows to 148 trillion Btu by 2040, when it accounts for 35% of total freight rail energy consumption, with fuel cost savings offsetting the incremental capital costs of LNG locomotives. CNG and LNG energy demand for buses grows from 13 trillion Btu in 2012 to 81 trillion Btu in 2040, primarily because of growth in CNG use for transit buses, which represents 28% of total energy consumption by buses in 2040. Use of CNG by LDVs and LNG by domestic marine vessels remains relatively minor, at 19.1 trillion Btu and 1.5 trillion Btu in 2040, or 2% and 0.2% of each mode's energy consumption, respectively.

## Growth in electricity use slows, but use still increases by 29% from 2012 to 2040

Figure MT-29. U.S. electricity demand growth in the Reference case, 1950-2040 (percent)



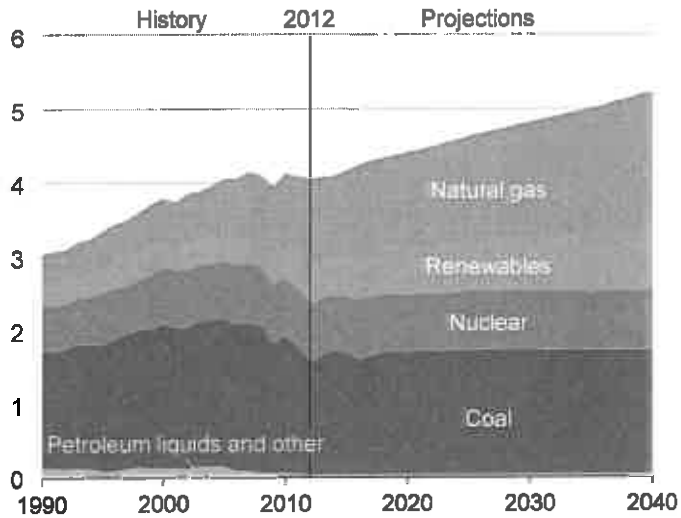

Growth of electricity demand (including retail sales and direct use) has slowed in each decade since the 1950s, from 9.8%/year from 1949 to 1959 to only 0.7%/year since 2000. In the AEO2014 Reference case, electricity demand growth remains relatively low, as rising demand for electric services is offset by efficiency gains from new appliance standards and investments in energy-efficient equipment (Figure MT-29). Total electricity demand grows by 29% (0.9%/year), from 3,826 billion kilowatthours (kWh) in 2012 to 4,954 billion kWh in 2040.

Retail electricity sales grow by 25% (0.8%/year) in the Reference case, from 3,686 billion kWh in 2012 to 4,623 billion kWh in 2040. Population shifts to warmer regions with greater cooling requirements affect both residential and commercial electricity sales. Residential electricity sales grow by 21%, to 1,657 billion kWh in 2040, with cooling needs offset by more efficient appliances and light bulbs. Electricity sales to the commercial sector rise by 27%, to 1,675 billion kWh in 2040, with continuous growth in demand for electrical devices and equipment. Sales to the industrial sector rise by 30%, initially in the primary metals and bulk chemical industries and later in the food, construction, and metal-based durables industries.

Electricity demand varies with different assumptions about economic growth, advances in energy-efficient technologies, and electricity prices. In the High Economic Growth case, electricity demand grows by 41% from 2012 to 2040, compared with 20% in the Low Economic Growth case and only 14% in the Best Available Demand Technology case. In the High Oil and Gas Resource Case, a 2% decline in electricity prices from 2012 to 2040, because of greater natural gas availability, results in demand growth of 35% over the same period. In contrast, in the Reference Case, electricity prices increase by 13% over the projection, while demand increases by 29%.

## By 2035, natural gas surpasses coal as the largest source of U.S. electricity generation

Figure MT-30. Electricity generation by fuel in the Reference case, 1990-2040 (trillion kilowatthours)

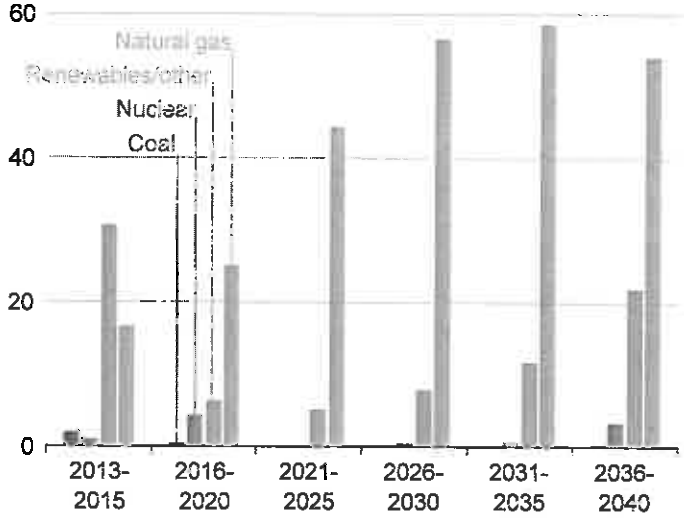



The share of electricity generated from natural gas grows steadily in the AEO2014 Reference case (Figure MT-30). The shift to natural gas occurs primarily as a result of its relatively low cost and coal-fired capacity retirements, although coal maintains the largest share of the generation mix through most of the projection. Changes in fuel mix are primarily a function of natural gas prices, which drive dispatch decisions for both coal and natural gas plants. Although a significant number of coal plants are retired early in the projection, the reduction in coal-fired generation is not proportional to the decline in capacity, because many of the coal plants projected to be retired currently operate at low capacity factors.

After 2020, increasing demand for electricity creates a need for new generating capacity, and natural gas plants account for more than 70% of all new capacity in the projection. As a result, the natural gas share of total electricity generation surpasses the coal share in 2035. Generation from nuclear power plants is relatively constant through 2040, increasing by an average of 0.2%/year, as 10 gigawatts (GW) of new capacity is brought online and 5 GW of older capacity is retired, and the nuclear share of total generation declines while the natural gas and renewable shares increase. Renewable generation grows by an average of 1.9%/year from 2012 through 2040 and makes up an increasing share of the generation mix in the Reference case. The non-hydropower share of total renewable generation increases from 45% in 2012 to 65% in 2040. The generation mix is sensitive to fuel prices and future policies and, therefore, varies significantly across the AEO2014 alternative cases.

## Most new capacity uses natural gas and renewables

Figure MT-31. Electricity generation capacity additions by fuel type, including combined heat and power, in the Reference case, 2013-40 (gigawatts)



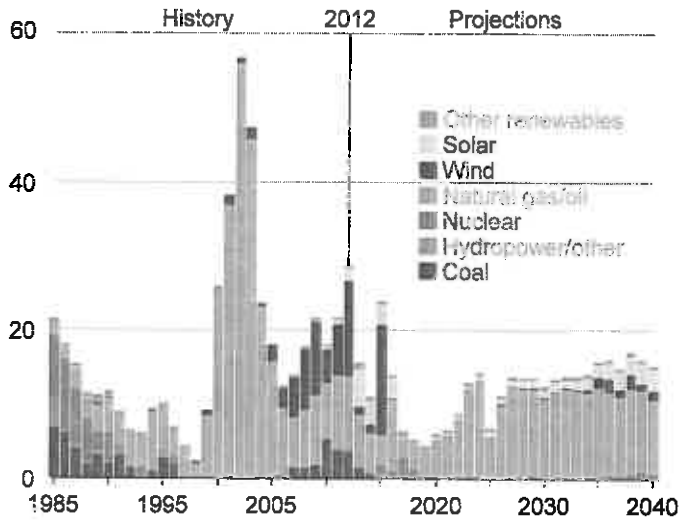

Decisions to add capacity, and the choice of fuel for new capacity, depend on a number of factors [8]. With growing electricity demand and the retirement of 97 GW of existing capacity, 351 GW of new generating capacity [9] is added in the AEO2014 Reference case from 2013 to 2040 (Figure MT-31).

Natural gas-fired plants account for 73% of capacity additions from 2013 to 2040 in the Reference case, compared with 24% for renewables, 3% for nuclear, and 1% for coal. Escalating construction costs have the largest impact on capital-intensive technologies, which include nuclear, coal, and renewables. However, federal tax incentives, nuclear loan guarantees, state energy programs, and rising prices for fossil fuels can increase the competitiveness of renewable and nuclear generating capacity. Federal and state environmental regulations also affect the use of fossil fuels, particularly coal, as does uncertainty about future limits on GHG emissions and other possible environmental programs (reflected in the Reference case by adding 3 percentage points to the cost of capital for new coal-fired capacity without carbon controls).

Uncertainty about demand growth and fuel prices also affects capacity planning. Capacity additions from 2013 to 2040 range from 263 GW in the Low Economic Growth case to 482 GW in the High Economic Growth case. In the Low Oil and Gas Resource case, with higher natural gas prices, new gas-fired capacity totals 181 GW, or 49% of total additions, from 2013 to 2040. In the High Oil and Gas Resource case, with natural gas prices that are lower than in the Reference case, 323 GW of new natural gas-fired capacity is added from 2013 to 2040, accounting for 83% of total new capacity.

## Additions to power plant capacity slow after 2016 but accelerate beyond 2023

Figure MT-32. Additions to electricity generating capacity in the Reference case, 1985-2040 (gigawatts)




Past investments in electricity generation capacity have gone through boom-and-bust cycles, with periods of slow growth followed by rapid growth in response to changing expectations for future electricity demand and fuel prices, as well as changes in the industry, such as restructuring. A construction boom in the early 2000s saw capacity additions averaging 35 GW/year from 2000 to 2005, but the average dropped to 19 GW/year from 2006 to 2012 (Figure MT-32).

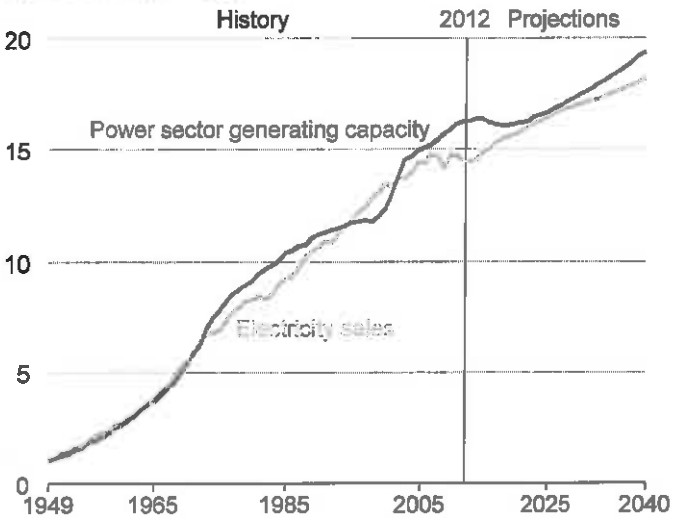
In the AEO2014 Reference case, capacity additions from 2013 to 2040 total 351 GW, including new plants in the power sector as well as end-use generators. Additions through 2016 average 16 GW/year, with 52% consisting of renewable plants built to take advantage of federal tax incentives and to meet state RPS. Eligibility rules for the wind production tax credit (PTC) allow new wind capacity coming online before 2016 to qualify, leading to a large increase just at the deadline.

Annual capacity additions drop significantly after 2016 and remain below 9 GW/year until 2023, while existing capacity is adequate to meet relatively slow demand growth in most regions and satisfy renewable requirements under state standards. From 2025 to 2040, annual builds average 14 GW/year, as what was previously excess capacity is again needed. About 79% of the capacity added from 2025 to 2040 is fueled with natural gas, given higher construction costs for other types of capacity and uncertainty about the prospects for future limits on GHG emissions.

Uncertainty about electricity demand growth affects annual capacity additions. In the Low Economic Growth case, annual additions average 10 GW/year from 2025 to 2040; in the High Economic Growth case, they increase to an average of 20 GW/year over the same period.

## Growth in power generating capacity parallels rising sales of electricity

Figure MT-33. Electricity sales and power sector generating capacity in the Reference case, 1949-2040 (indices, 1949 = 1.0)



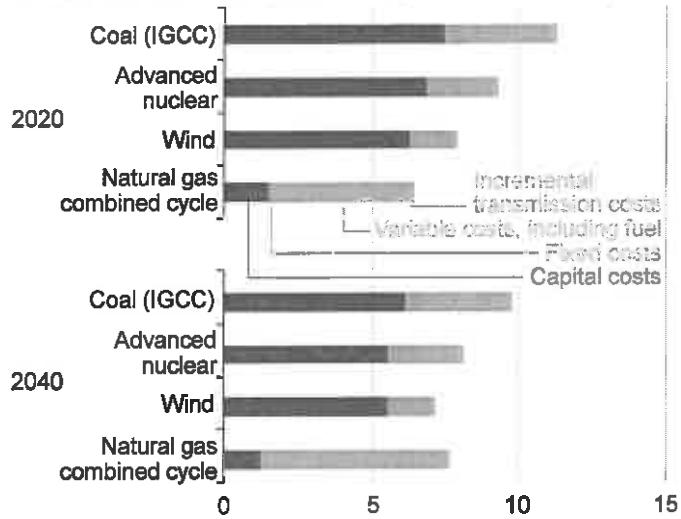

In the long term, growth in generating capacity parallels growth in electricity demand. However, unexpected shifts in demand or changes that affect capacity investment decisions can cause imbalances that may take years to work out. Capacity growth has outpaced demand since the 2007-09 economic recession that resulted in flat or declining demand. Low natural gas prices and tax incentives for renewable technologies have contributed to increases in those capacity types, even while most regions had sufficient capacity to serve load with an adequate reserve margin.

Figure MT-33 shows indexes summarizing relative changes in total power sector generating capacity and electricity sales. During the 1950s and 1960s, capacity and demand indexes tracked closely; but energy crises in the 1970s and 1980s slowed demand growth, with capacity additions outpacing demand for more than 10 years, as planned units continued to come online. Demand and capacity were aligned again in the mid-1990s, but in the late 1990s uncertainty about industry deregulation led to a downturn in capacity expansion, and another period of imbalance followed, with demand growth exceeding capacity growth.

In 2000, a boom in construction of new natural gas-fired plants brought capacity back into balance with demand, but capacity continued to grow, creating excess. Construction of new wind capacity also grew after 2000. Excess capacity remains in the early years of the AEO2014 Reference case, until retirements eventually bring capacity growth and demand growth back into balance after 2023. In the later years, total capacity grows at a rate slightly higher than demand growth, due in part to an increase in intermittent renewable capacity that does not contribute to meeting demand in the same proportion as dispatchable capacity.

## Costs and regulatory uncertainties vary across options for new capacity

Figure MT-34. Average levelized electricity costs for new power plants, excluding subsidies, in the Reference case, 2020 and 2040 (2012 cents per kilowatthour)




Technology choices for new generating capacity are based largely on capital, operating, and transmission costs [*10*]. Coal, nuclear, and wind plants are capital-intensive (Figure MT-34), whereas operating (fuel) expenditures make up most of the costs for natural gas plants. Capital costs depend on such factors as equipment costs, interest rates, and capital cost recovery periods, which vary with technology. Fuel costs vary with operating efficiency, fuel price, and transportation costs.

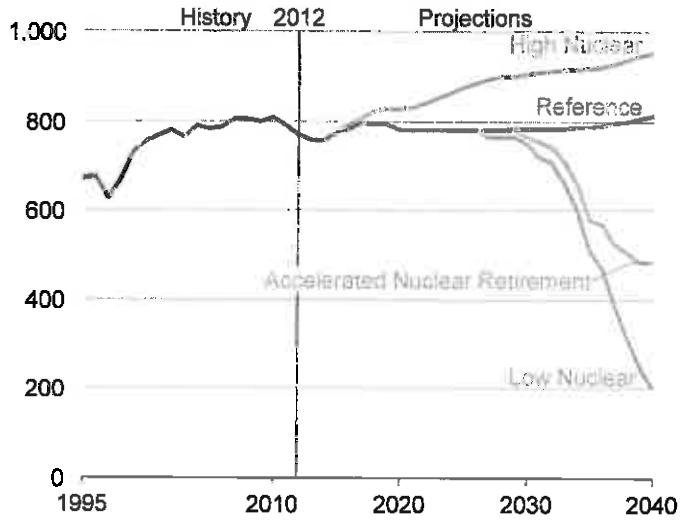
Capital costs can decline over time as developers gain technology experience, with the largest rate of decline observed for new technologies. In the AEO2014 Reference case, the capital costs of new technologies are adjusted upward initially to compensate for the optimism inherent in early estimates of project costs, then they decline as project developers gain experience. The decline continues at a progressively slower rate as more units are built. Operating efficiencies also are assumed to improve over time, resulting in reduced variable costs unless increases in fuel costs exceed the savings from efficiency gains.

In addition to considerations of levelized costs [*11*], some technologies and fuels receive subsidies, such as production or investment tax credits. Also, new plants must satisfy local and federal emissions standards and be compatible with the utility's load profile to maximize revenue.

Regulatory uncertainty also affects capacity planning. Laws and regulations may require new coal plants to include carbon control and sequestration equipment, resulting in higher material, labor, and operating costs. Because nuclear and renewable power plants (including wind plants) do not emit greenhouse gases, their costs are not directly affected by these specific sources of regulatory uncertainty.

## Nuclear electricity generation varies with license renewals, uprates, and operating costs

Figure MT-35. Nuclear electricity generation in four cases, 1995-2040 (billion kilowatthours)



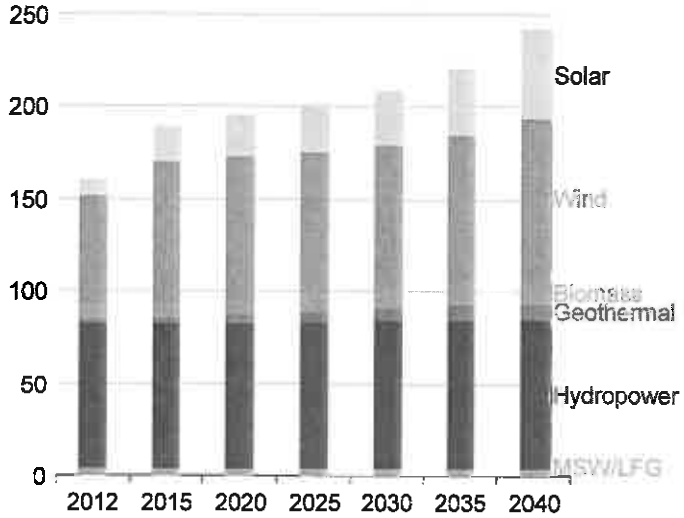

Projections of nuclear capacity and generation are influenced by assumptions about the potential for capacity uprates, new licensing requirements, future operating costs, and outside influences such as natural gas prices and incentives for other generating technologies. In the Reference case, nuclear capacity and generation remain relatively flat, with early retirements offset by new additions (Figure MT-35).

As discussed in AEO2014 Issues in focus, the Accelerated Nuclear Retirement case assumes no new nuclear builds beyond those currently under construction; that all existing units are retired by 60 years of age; and that nonfuel operating costs at existing nuclear plants increase by 3% annually, similar to recent rates. In this case, 42 gigawatts (GW) of nuclear capacity is retired, mostly from 2030 to 2040. The Low Nuclear case combines those assumptions with the High Oil and Gas Resource case and the No Sunset case. Lower natural gas prices make existing and new natural gas units more economical, and together with tax credits for newly added renewable capacity, they lower electricity market prices. With rising operating costs for nuclear plants and lower electricity prices, 77 GW of nuclear capacity is retired before 60 years of life. The retired nuclear capacity is replaced primarily by natural gas capacity, leading to a 6% increase in $CO_2$ emissions in the electric power sector in 2040.

The High Nuclear case assumes more uprates of existing units, adding 6.0 GW of capacity, and the addition of 12.6 GW of planned capacity through 2027. As a result, total nuclear generation in 2040 is 17% higher than in the Reference case, reducing the need for additional natural gas-fired generation.

## Solar photovoltaics and wind dominate renewable capacity growth

Figure MT-36. Renewable electricity generating capacity by energy source, including end-use capacity in the Reference case, 2012-40 (gigawatts)



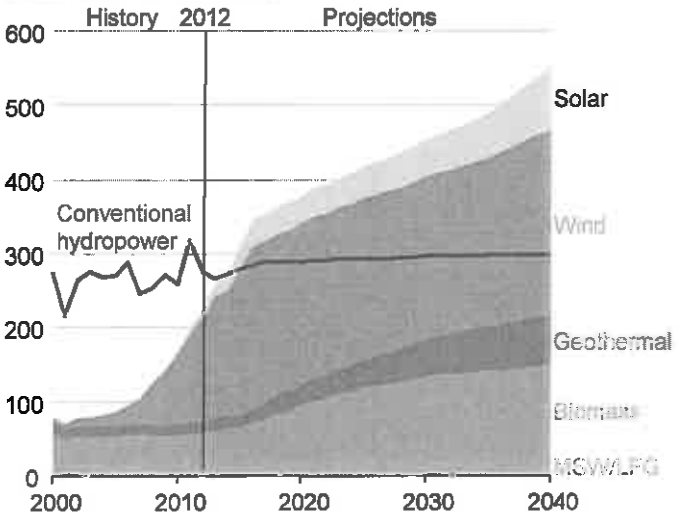

Total renewable generating capacity grows by 52% from 2012 to 2040 in the AEO2014 Reference case. Nonhydropower renewable capacity, particularly wind and solar, nearly doubles (Figure MT-36) and accounts for almost all of the growth in renewable capacity.

Solar power leads the growth in renewable capacity, increasing from less than 8 GW in 2012 to more than 48 GW in 2040. Wind capacity increases from less than 60 GW in 2012 to 87 GW in 2040, the second-largest amount of new renewable capacity. Although geothermal capacity more than triples and biomass capacity nearly doubles in the projection, combined they account for less than 15% of renewable capacity additions. Wind is the top source of nonhydropower renewable capacity in the projection, surpassing the hydropower share in 2036.

Renewable capacity growth is supported by a variety of federal and state policies, particularly state renewable portfolio standards (RPS) and federal tax credits. However, the impact of those policies is limited later in the projection period, because individual state renewable targets stop increasing by 2025, and projects must generally be online by 2016 to qualify for currently available federal tax credits. In addition, growth in electricity demand is modest and natural gas prices are relatively low after 2025. Renewable capacity grows by an average of 0.7%/year from 2020 to 2030, compared with 3.8%/year from 2010 to 2020. However, as natural gas prices rise over the projection period, renewable capacity becomes an increasingly cost-competitive option in some regions, and the total grows by an average of 1.5%/year overall from 2030 to 2040.

## Total generation from wind, solar, and other renewables surpasses hydropower

Figure MT-37. Renewable electricity generation by type, all sectors, in the Reference case, 2000-40 (billion kilowatthours)



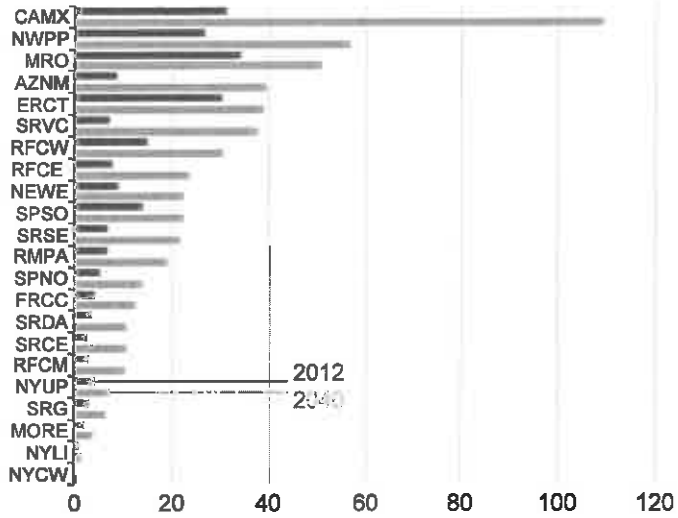

Total renewable electricity generation grows by 1.9%/year on average in the Reference case, from 502 billion kWh in 2012 to 851 billion kWh in 2040. Nonhydropower renewables, averaging 3.2%/year growth, account for nearly all of the growth, with their total surpassing hydropower (the previous leader of renewable generation) in 2014 and accounting for about two-thirds of all renewable generation in 2040 (Figure MT-37).

Solar energy is the fastest-growing source of renewable generation, increasing by 7.5%/year from 2012 to 2040, almost exclusively as a result of increased photovoltaic capacity in both the electric power (central-station) and end-use (customer-sited) sectors. Wind generation grows by an average of 2.0%/year but provides the largest absolute increase in renewable generation. From 2012 to 2016, wind power developers take advantage of the existing federal PTC, which requires plants to be under construction by the end of 2013 to qualify.

Geothermal power is the second-fastest-growing source of renewable electricity generation in the Reference case, increasing from less than 16 billion kWh in 2012 to 67 billion in 2040—a 5.4% average annual growth rate. Biomass generation also grows significantly, increasing by an average of 4.4%/year from 2012 to 2040, primarily as a result of increased use of co-firing technology in the electric power sector in the near- to mid-term. Co-firing is encouraged by state-level policies and increasing regional cost-competitiveness with coal. In the long run, the growth of biomass generation is supported by increased capacity at dedicated biomass plants in the electric power sector, as well as combined heat and power plants in the industrial sector.

## California leads renewable electricity generation growth

Figure MT-38. Regional nonhydropower renewable electricity, including end-use generation, in the Reference case, 2012 and 2040 (billion kilowatthours)



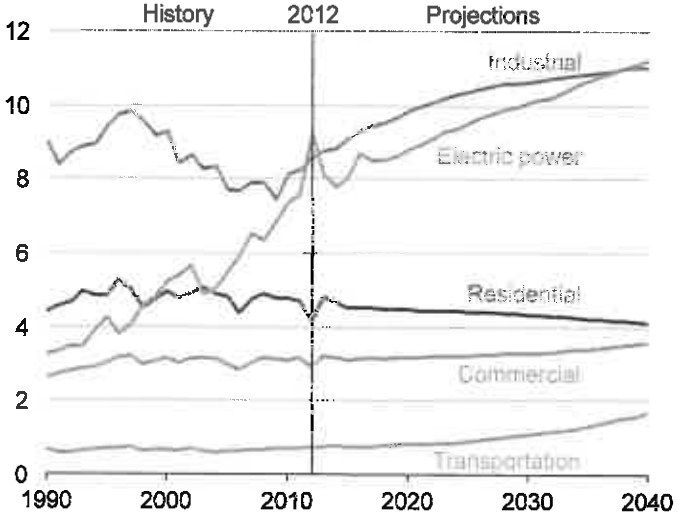

In the AEO2014 Reference case, nonhydropower renewable generation increases from 2012 to 2040 in all modeled electricity regions (for a map of the regions and definition of acronyms, see Appendix F). Its growth is faster in some regions than in others, and the penetration in the generation mix and resulting increases in generation vary substantially among regions (Figure MT-38).

Regional growth in nonhydropower renewable generation is mainly driven by three factors: state RPS, availability of renewable energy resources, and cost competiveness with fossil fuel technologies. Factors such as electricity demand growth, non-RPS policies (such as net metering), and electricity prices also affect the rate of growth, which tends to be strongest in regions where a combination of factors is in place.

The WECC California (CAMX) region accounts for both the highest absolute level of nonhydropower renewable generation in 2040 and the largest growth from 2012 to 2040, which is supported by an aggressive RPS, availability of solar, wind, and geothermal resources, and relatively high electricity prices. The AZNM (Arizona, New Mexico, and Nevada) and SRVC (Virginia, North Carolina, and South Carolina) regions show the next-highest increases in nonhydropower renewable generation from 2012 to 2040. In the AZNM region, growth is supported by mandatory RPS standards, above-average electricity demand growth, and the availability of solar and wind resources. Although Virginia and South Carolina do not have mandatory policies in place, the SRVC region has robust biomass and solar resources and relatively high fossil fuel prices.

## Industrial and electric power sectors drive growth in U.S. natural gas consumption

Figure MT-39. Natural gas consumption by sector in the Reference case, 1990-2040 (trillion cubic feet)




U.S. total natural gas consumption grows from 25.6 trillion cubic feet (Tcf) in 2012 to 31.6 Tcf in 2040 in the AEO2014 Reference case. Natural gas use increases in all of the end-use sectors except residential (Figure MT-39). Natural gas use for residential space heating declines as a result of population shifts to warmer regions of the country and improvements in appliance efficiency.

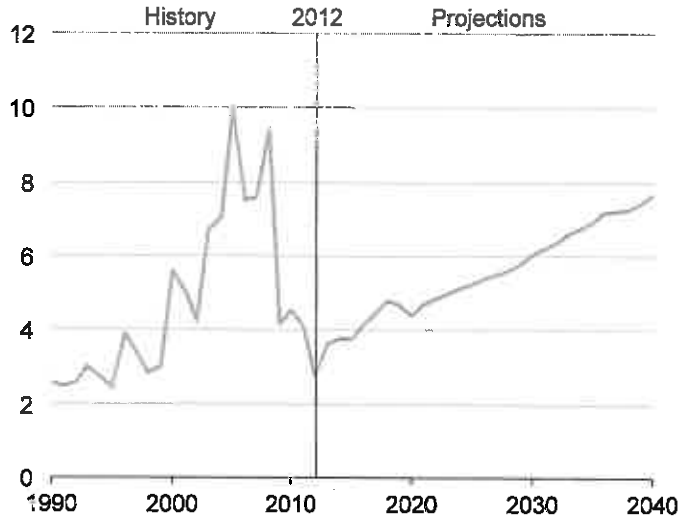
Consumption of natural gas for electric power generation grows by about 2 Tcf and makes up about 33% of the increase in total natural gas consumption by 2040. Relatively low natural gas prices make natural gas an attractive fuel for serving increased load. Natural gas is also the fuel most often used to replace older coal-fired generation as it is retired.

From 2012 to 2040, natural gas consumption in the industrial sector increases by 2.5 Tcf, an average of 0.9%/year, representing about 26% of the total increase in natural gas consumption. As industrial output grows, the energy-intensive industries take advantage of relatively low natural gas prices, particularly through 2028. After 2028, industrial sector consumption of natural gas continues to grow but at a somewhat slower rate, in response to rising prices.

Although transportation use currently accounts for only a small portion of total U.S. natural gas consumption, natural gas use by heavy-duty vehicles (HDVs), trains, and ships shows the largest percentage growth of any fuel in the projection. Consumption in the transportation sector, excluding natural gas use at compressor stations, grows from about 40 billion cubic feet (Bcf) in 2012 to 850 Bcf in 2040.

## Natural gas prices rise with an expected increase in production costs

Figure MT-40. Annual average Henry Hub spot natural gas prices in the Reference case, 1990-2040 (2012 dollars per million Btu)

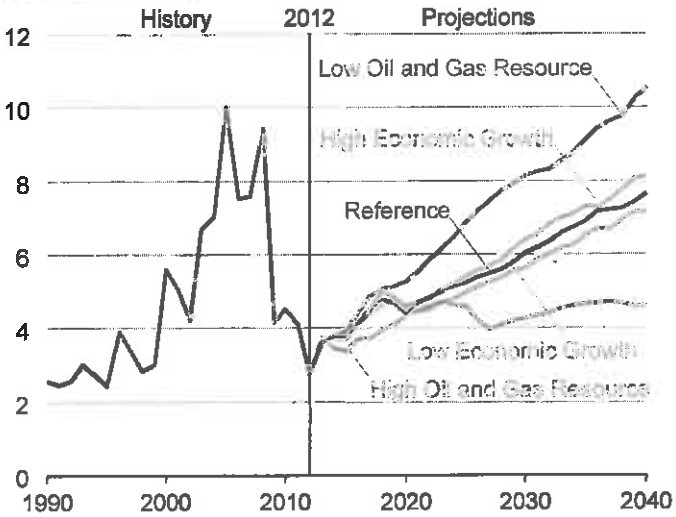



Average annual U.S. natural gas prices have remained relatively low over the past several years as a result of the availability of abundant domestic resources and the application of improved production technologies. To provide the supplies necessary to meet growth in natural gas consumption and a rise in exports in the AEO2014 Reference case, producers move into areas where the recovery of natural gas is more difficult and expensive, which leads to an increase in Henry Hub spot prices over the projection period. Henry Hub spot prices for natural gas increase by an average of 3.7%/year in the Reference case, from $2.75/million Btu (MMBtu) in 2012 to $7.65/MMBtu (2012 dollars) in 2040 (Figure MT-40).

Growth in demand for natural gas, largely from the electric power and industrial sectors and for liquefied natural gas (LNG) exports, results in upward pressure on prices, particularly in the 2015-18 period. Delivered prices to residential, commercial, industrial, and electric power consumers generally rise with Henry Hub prices in the projection, but the lower 48 average spot price increases at a slightly slower rate than the Henry Hub spot price, because regional production growth in areas that do not serve the Henry Hub is somewhat faster than growth in areas that supply the Henry Hub. In particular, dry gas production in the Marcellus shale play, which predominantly serves the Northeastern and Mid-Atlantic regions, grows from 1.9 Tcf in 2012 to 5.0 Tcf in 2022 in the Reference case, before declining to 4.6 Tcf in 2040. Total onshore production in the Northeast region grows on average by 3.2%/year, from 3.3 Tcf in 2012 to 8.1 Tcf in 2040, while combined onshore and offshore production in the Gulf region grows by 2.1%/year, from 7.3 Tcf in 2012 to 13.0 Tcf in 2040.

## Natural gas prices depend on economic growth and resource recovery rates among other factors

Figure MT-41. Annual average Henry Hub spot prices for natural gas in five cases, 1990-2040 (2012 dollars per million Btu)



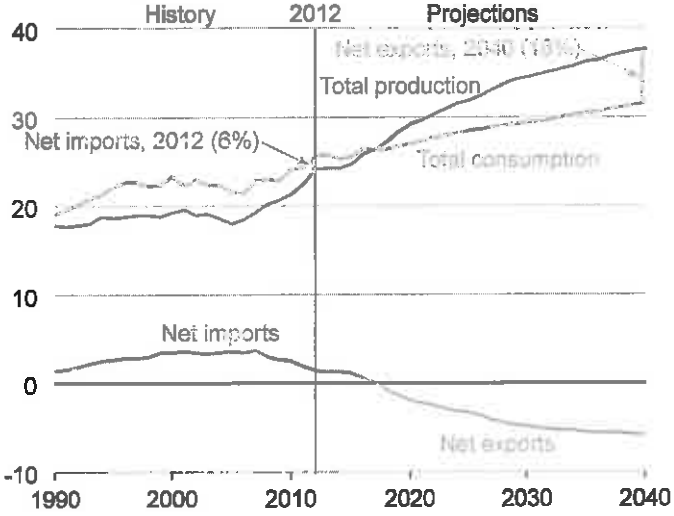

The projection of natural gas prices depends on many factors, including macroeconomic growth rates and expected rates of resource recovery from natural gas wells. Higher rates of economic growth lead to increased consumption of natural gas, primarily in response to their effects on housing starts, commercial floorspace, and industrial output. In the High Economic Growth case, higher levels of consumption result in more rapid increases both in depletion of natural gas resources and in the cost of developing new production, pushing natural gas prices higher. The converse is true in the Low Economic Growth case (Figure MT-41). In the High and Low Economic Growth cases, the price rises by 4.0%/year and 3.5%/year, respectively, compared with 3.7%/year in the Reference case.

The rate of resource recovery from oil and natural gas wells has a direct impact on the cost per unit of production and, in turn, prices. The High Oil and Gas Resource case assumes higher estimates for recoverable crude oil and natural gas resources in tight wells and shale formations and for offshore resources in the lower 48 states and Alaska than in the Reference case. The Low Oil and Gas Resource case assumes lower estimated ultimate recovery of natural gas from each shale well or tight well than in the Reference case. In the Low and High Oil and Gas Resource cases, Henry Hub spot natural gas prices increase by 4.9%/year and 1.8%/year, respectively. (An article in the Issues in focus section, "U.S. tight oil production: Alternative supply projections and an overview of EIA's analysis of well-level data aggregated to the county level," provides more information on the alternative resource cases.)

In both cases, there are mitigating effects that dampen the initial price response from the demand or supply shift. For example, lower natural gas prices lead to increases in natural gas exports and demand, which place some upward pressure on natural gas prices.

## With production growing faster than use, the U.S. becomes a net exporter of natural gas

Figure MT-42. Total natural gas production, consumption, and imports in the Reference case, 1990-2040 (trillion cubic feet)




In the AEO2014 Reference case, natural gas production grows by an average rate of 1.6%/year from 2012 to 2040, more than double the 0.8% annual growth rate of total U.S. consumption over the period. The growth in production meets increasing demand and exports (liquefied natural gas [LNG] and pipeline exports), while also making up for a drop in natural gas imports. The United States becomes a net exporter of natural gas before 2020.

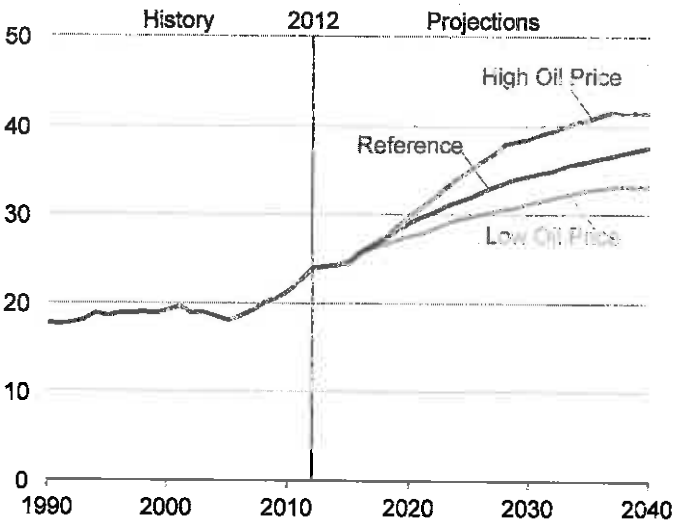
The development of shale gas resources spurs growth in natural gas production, with producers seeing higher prices as a result of growing demand, especially from both the industrial and electricity generation sectors. Growing LNG exports also support higher natural gas prices.

The United States transitions from being a net importer of 1.5 Tcf of natural gas in 2012 to a net exporter of 5.8 Tcf in 2040, with 88% of the rise in net exports (6.5 Tcf) occurring by 2030, followed by slower growth through 2040 (Figure MT-42).

Net LNG exports, primarily to Asia, increase by 3.5 Tcf from 2012 to 2030, then remain flat through 2040. Prospects for future LNG exports are uncertain, depending on many factors that are difficult to anticipate. The increase in net LNG exports to Asia through 2030 accounts for 55% of the rise in total net natural gas exports, with the remainder coming from decreased net pipeline imports from Canada and increased net pipeline exports to Mexico. Net pipeline imports from Canada drop from 2.0 Tcf in 2012 to 0.4 Tcf in 2030, mainly as a result of lower imports to the western United States. Imports from Canada increase to 0.7 Tcf in 2040, with higher imports into the northeastern United States. In contrast, net pipeline exports to Mexico grow steadily, from 0.6 Tcf in 2012 to 3.1 Tcf in 2040.

## U.S. natural gas production, use, and exports all are affected by oil prices

Figure MT-43. U.S. natural gas production in three cases, 1990-2040 (trillion cubic feet per year)



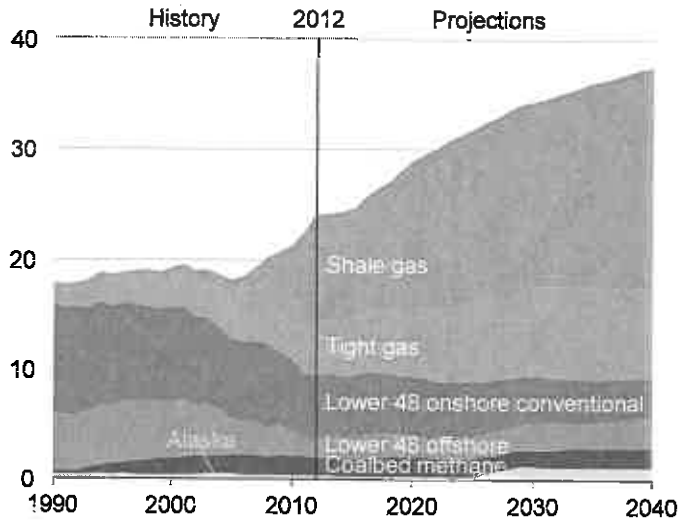

U.S. natural gas production is affected by crude oil prices primarily through changes in natural gas consumption and exports. Across the oil price cases, the largest changes in consumption are seen for natural gas consumed in transportation and natural gas exported as LNG.

The profitability of natural gas as a transportation fuel or as LNG for export depends primarily on the price differential between crude oil and natural gas. For example, in the Low Oil Price case, the average difference between oil prices and natural gas prices from 2012 through 2040 is about $7.70 per million Btu (MMBtu). With that low price differential, virtually no natural gas is consumed in the transportation sector, and little LNG is exported. In the High Oil Price case, in contrast, the average price difference is about $21.90/MMBtu, which provides substantial incentive for direct use of natural gas in transportation and for conversion to LNG for export.

Across the oil price cases, total natural gas production varies by 8.3 Tcf in 2040 (Figure MT-43), with changes in LNG exports accounting for 6.3 Tcf and changes in direct consumption for transportation accounting for 2.2 Tcf. The increase in LNG exports and transportation consumption is offset to some extent by lower natural gas consumption in other sectors, with spot prices for natural gas from 2012 to 2040 averaging about $0.70/MMBtu higher in the High Oil Price case than in the Low Oil Price case.

## Shale gas provides the largest source of growth in U.S. natural gas supply

Figure MT-44. U.S. natural gas production by source in the Reference case, 1990-2040 (trillion cubic feet)




The 56% increase in total natural gas production from 2012 to 2040 in the AEO2014 Reference Case results from increased development of shale gas, tight gas, and offshore natural gas resources (Figure MT-44). Shale gas production is the largest contributor, growing by more than 10 Tcf, from 9.7 Tcf in 2012 to 19.8 Tcf in 2040. The shale gas share of total U.S. natural gas production increases from 40% in 2012 to 53% in 2040. Tight gas production and offshore gas production increase by 73% and 78%, respectively, from 2012 to 2040, but their shares of total production remain relatively constant.

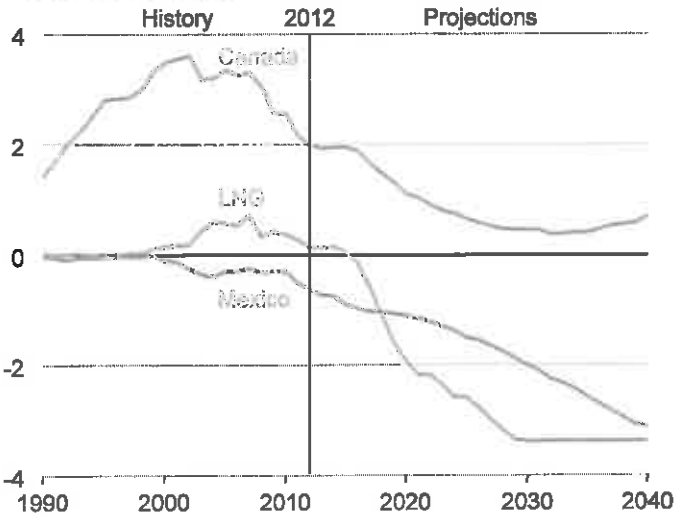
From 2017 to 2022, U.S. offshore natural gas production declines by 0.3 Tcf, as offshore exploration and development activities are directed primarily toward oil resources in the Gulf of Mexico. Offshore natural gas production increases after 2022, growing to 2.9 Tcf in 2040, as natural gas prices rise.

Alaska's natural gas production also increases during the projection period, because of Alaska LNG exports to overseas customers, beginning in 2026 and increasing to 0.8 Tcf (2.2 Bcf/d) in 2029. Alaska's LNG exports level off at 0.8 Tcf per year over the last decade of the projec-tion. Alaska's total natural gas production in 2040 is 1.2 Tcf.

Although U.S. natural gas production rises throughout the projection, the mix of sources changes over time. Onshore non-associated production (from sources other than tight gas, shale gas, and coalbed methane) declines from 3.9 Tcf in 2012 to 1.6 Tcf in 2040, and in 2040 it accounts for only about 4% of total domestic production, down from 16% in 2012.

## U.S. exports to North American and overseas gas markets increase as gas production rises

Figure MT-45. U.S. net imports of natural gas by source in the Reference case, 1990-2040 (trillion cubic feet)



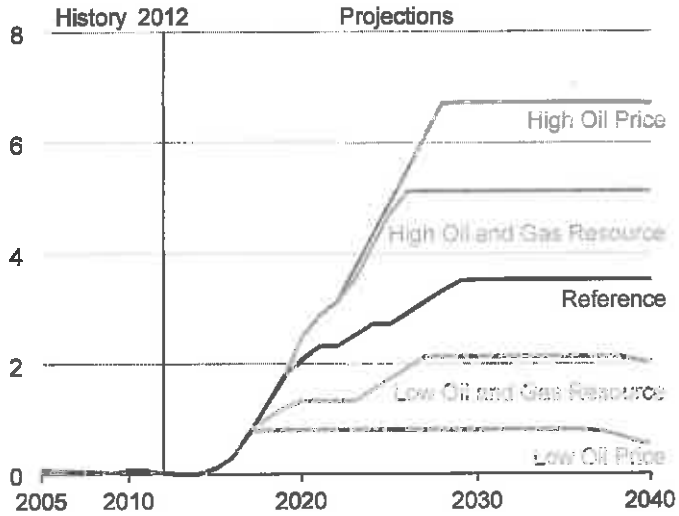

With relatively low natural gas prices in the AEO2014 Reference case, the United States becomes a net exporter of natural gas in 2018, with net exports growing to 5.8 Tcf in 2040. Most of the projected growth in exports consists of LNG exported to overseas markets. From 2012 to 2040, U.S. net exports of LNG increase by 3.5 Tcf (Figure MT-45), including 0.8 Tcf of LNG originating in south-central Alaska, with the remaining volumes originating from export terminals located along the Atlantic and Gulf coasts. In general, future U.S. LNG exports depend on a number of factors that are difficult to anticipate, including the speed and extent of price convergence in global natural gas markets, the extent to which natural gas competes with oil in U.S. and international gas markets, and the pace of natural gas supply growth outside the United States.

The next-largest growth market for U.S. natural gas exports is pipeline exports to Mexico, which increase from 0.6 Tcf in 2012 to 3.1 Tcf in 2040. The increase in exports to Mexico reflects a growing gap between Mexico's natural gas consumption and production. However, Mexico's recently enacted legislation to restructure its oil and gas industry could reduce the need for U.S. natural gas exports to Mexico in the future.

Net natural gas imports from Canada decline through 2033, when they reach a low point of about 0.4 Tcf. After 2033, higher natural gas prices in the lower 48 improve the economics of Canadian natural gas exports to the U.S. West Coast. In 2040, net U.S. imports of natural gas from Canada total about 0.7 Tcf.

## LNG export growth depends on price and productivity assumptions

Figure MT-46. U.S. exports of liquefied natural gas in five cases, 2005-40 (trillion cubic feet)



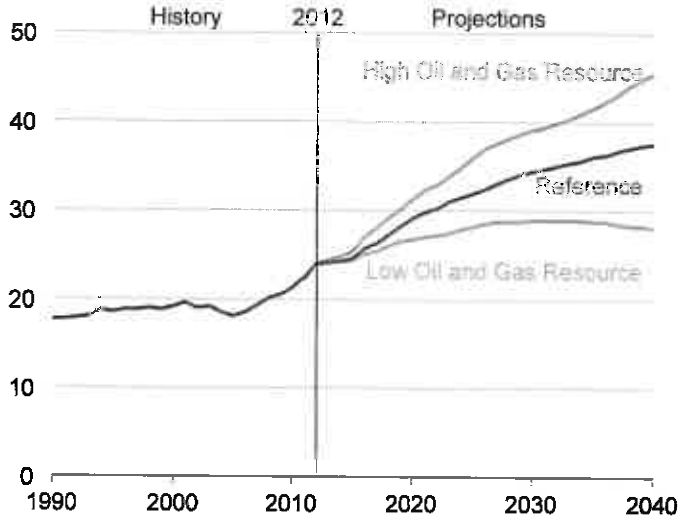

In the AEO2014 Reference case, growing natural gas production from shale gas and tight oil formations supports an increase in U.S. exports of LNG and pipeline gas. Net exports of LNG increase by 3.5 Tcf from 2012 to 2040, representing 48% of the total increase in U.S. natural gas net exports over the period. The United States becomes a net LNG exporter in 2016, with gross exports reaching their peak level of 3.5 Tcf in 2030.

The United States is a net LNG exporter in all of the AEO2014 oil price and resource cases; however, LNG export levels vary significantly by case. In the High Oil Price case, where both global LNG demand and LNG prices are higher than in the Reference case, LNG exports increase to 6.7 Tcf in 2028 and remain at that level through 2040 (Figure MT-46). Conversely, in the Low Oil Price case, gross LNG exports increase to only 0.8 Tcf in 2018, where they remain through most of the projection period. The LNG export projections in AEO2014 are based on a generalized economic evaluation and do not reflect a specific evaluation or knowledge of decisions on pending LNG export applications.

In the High Oil and Gas Resource case, large production increases put downward pressure on U.S. natural gas prices, and as a result LNG exports climb to 5.1 Tcf after 2025. The Low Oil and Gas Resource case assumes lower natural gas production and higher domestic gas prices. Gross LNG exports in the Low Oil and Gas Resource case reach 2.1 Tcf by 2027.

## U.S. natural gas production rates depend on resource availability and production costs

Figure MT-47. U.S. natural gas production in three cases, 1990-2040 (trillion cubic feet per year)



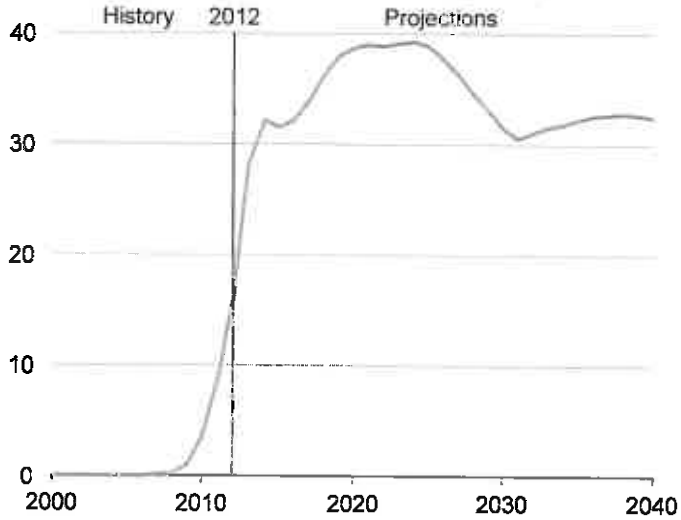

Prospects for production from tight oil and shale gas resources are uncertain, both because large portions of the formations have little or no production history, and because future technology could increase well productivity while reducing costs. The Low Oil and Gas Resource and High Oil and Gas Resource cases illustrate the potential impacts of changes in the Reference case assumptions regarding technology advances and the resource size and quality.

The High Oil and Gas Resource case assumes (1) higher estimates of onshore lower 48 tight oil, tight gas, and shale gas resources than in the Reference case, as a result of higher estimated ultimate recovery (EUR) per well and closer well spacing; (2) tight oil development in Alaska; (3) higher estimates of offshore resources in Alaska and the lower 48 states; and (4) higher rates of long-term technology improvement. In the High Resource case, higher well productivity reduces development and production costs per unit, resulting in more and earlier resource development than in the Reference case. With the greater abundance of less-expensive shale gas resources, cumulative shale gas production from 2012 through 2040 totals 540 Tcf, as compared with 442 Tcf in the Reference case. In the Reference case and the High Resource case, total natural gas production in 2040 grows to 37.5 Tcf and 45.5 Tcf per year, respectively.

In the Low Oil and Gas Resource case, which assumes lower tight oil, tight gas, and shale gas resources than in the Reference case, total natural gas production plateaus at just under 29 Tcf per year from 2027 through 2036, then declines to 28.1 Tcf in 2040 (Figure MT-47). Shale gas production peaks in 2030 at 13.1 Tcf and declines to 11.6 Tcf in 2040. From 2012 to 2040, cumulative shale gas production totals 341 Tcf in the Low Oil and Gas Resource case.

## Marcellus shale gas production growth changes U.S. natural gas transportation patterns

Figure MT-48. Marcellus shale production share of total U.S. natural gas consumption east of the Mississippi River in the Reference case, 2000-40 (percent)



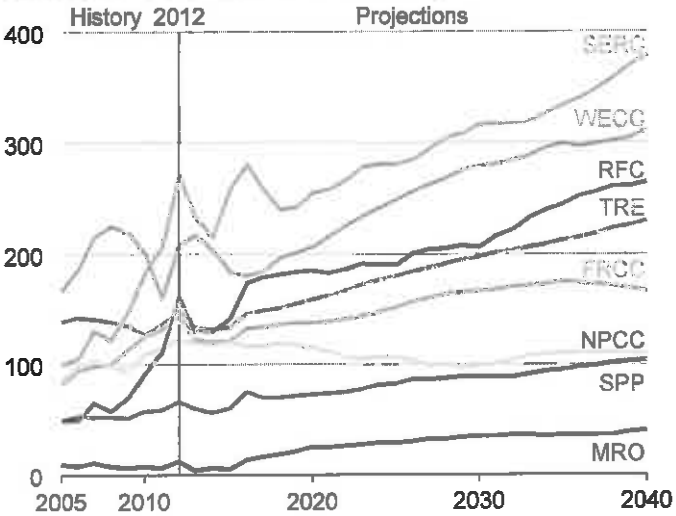

Historically, natural gas produced in Texas, Louisiana, Oklahoma, and the offshore Gulf of Mexico has been transported to markets east of the Mississippi River. In addition, significant volumes of natural gas have been transported from Canada and the Rocky Mountains to serve the same markets. However, the advent of large-scale natural gas production in the Marcellus shale formation, located in Appalachia, will alter natural gas transportation patterns east of the Mississippi River.

In the AEO2014 Reference Case, natural gas production from the Marcellus shale grows from 1.9 Tcf in 2012 to a peak production volume of about 5.0 Tcf per year from 2022 through 2025. Marcellus shale gas production could provide up to 39% of the natural gas needed to meet demand in markets east of the Mississippi River during that period—up from 16% in 2012. Although Marcellus gas production declines after 2024 in the Reference case, it still provides enough natural gas to meet at least 31% of the region's total demand for natural gas through 2040 (Figure MT-48).

Marcellus natural gas exceeds 100% of the demand projected for the New England and Mid-Atlantic Census Divisions from 2016 through 2040 in the Reference case, requiring transportation of some Marcellus gas to other markets. During the expected peak production period for the Marcellus shale, from 2022 through 2025, its total production exceeds natural gas consumption in the New England and Middle Atlantic regions by more than 1.0 Tcf over the period.

## Natural gas-fired generation grows strongly in the electric power sector

Figure MT-49. Natural gas-fired generation in the electric power sector by NERC region in the Reference case, 2005–40 (billion kilowatthours)




Consumption of natural gas by the U.S. electric power sector grows by an average of 0.7%/year from 2012 to 2040 in the AEO2014 Reference case. That growth is equivalent to 42% of the total increase in electricity generation over the period. While the coal-fired share of total generation in the electric power sector declines from 39% in 2012 to 34% in 2040, the natural gas share rises from 29% to 33%.

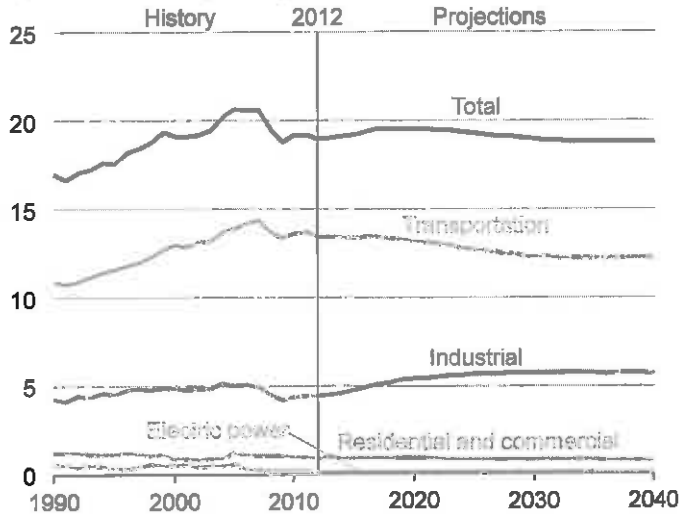
The increase in natural gas-fired generation is generally more pronounced in regions where coal-fired power plants are retired, including the SERC Reliability Corporation (SERC) and ReliabilityFirst Corporation (RFC) regions (Figure MT-49). The retirement of coal-fired capacity in the SERC region from 2012 to 2040, at 12.9 GW, is the country's second largest, and its increase in natural gas-fired generation over the same period, at 109 million MWh, is the largest. The largest decrease in coal-fired capacity (21.7 GW) is in the RFC region, which also has the third-largest increase in natural gas-fired generation, at 103 million MWh.

Two other regions with large increases in natural gas-fired generation in the Reference case are the Western Electricity Coordinating Council (WECC) and the Texas Reliability Entity (TRE). Those two regions do not have large retirements of coal-fired generation capacity, but they do have significant overall growth in electricity demand, most of which is met with natural gas-fired generation. WECC has the country's second-largest increase in natural gas-fired generation from 2012 to 2040 (105 million MWh), and TRE has the fourth-largest increase (81 million MWh).

In the RFC and TRE regions, natural gas-fired generation meets the vast majority of growth in electricity demand through 2040. Despite retirements of coal units, coal generation still meets a significant portion of demand in the SERC region. In the WECC region, renewables meet a significant portion of demand growth.

## Led by transportation, petroleum and other liquids consumption declines

Figure MT-50. Consumption of petroleum and other liquids by sector in the Reference case, 1990–2040 (million barrels per day)



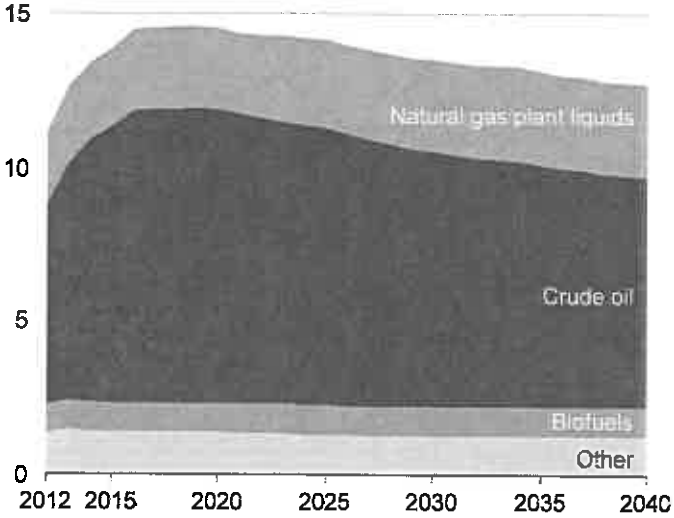

Consumption of petroleum and other liquids remains relatively flat in volumetric terms in the AEO2014 Reference case (Figure MT-50). While the transportation sector accounts for the largest share of total consumption throughout the projection, its share falls from 72% in 2013 to 65% in 2040, as a result of improvements in vehicle efficiency following the incorporation of corporate average fuel economy (CAFE) standards for both light-duty vehicles (LDVs) and heavy-duty vehicles (HDVs). In the industrial sector, consumption in the chemicals industry increases by 1.3 million barrels per day (MMbbl/d) from 2012 to 2040, largely reflecting higher volumes of hydrocarbon gas liquids as the sector benefits from increased U.S. production of natural gas. Consumption in all other industry segments decreases between 2012 and 2040.

Motor gasoline, ultra-low-sulfur diesel fuel, and jet fuel are the primary transportation fuels, all of which can include biofuels and may be supplemented by natural gas. Total motor gasoline consumption increases from 2012 to 2015 before dropping by approximately 2.1 MMbbl/d from 2015 to 2040 in the Reference case, while total diesel fuel consumption increases from 3.4 MMbbl/d in 2012 to 4.3 MMbbl/d in 2040, primarily for use in HDVs.

Both ethanol blending into gasoline and E85 consumption are essentially flat throughout the projection period, as a result of declining gasoline consumption and limited penetration of FFVs. The rapid rise of U.S. crude oil production, combined with the decline in motor gasoline demand and a modest increase in diesel fuel demand, reduces market opportunities for CTL and GTL technologies.

## Crude oil leads initial growth in liquids supply, next-generation liquids grow slowly after 2020

Figure MT-51. U.S. production of petroleum and other liquids by source in the Reference case, 2012-40 (million barrels per day)




In the AEO2014 Reference case, petroleum and other liquids supply grows through 2019 as a result of increases in production of tight oil (including condensates) and natural gas plant liquids (NGPL) (Figure MT-51). Total liquids production grows from 11.1 MMbbl/d in 2012 to a peak of 14.6 MMbbl/d in 2019, then drops to 12.7 MMbbl/d in 2040—still above 2012 levels—as tight oil production declines.

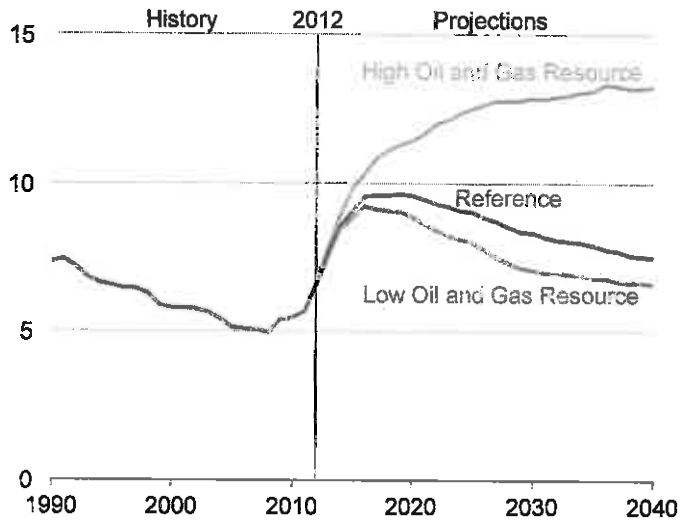
Production of hydrocarbon gas liquids (HGL) [12] increases throughout the projection. HGL is a new term introduced in the analysis to account for NGPL produced from natural gas processing plants and fractionators, and the liquefied refinery gases from crude oil in refineries. NGPL production increases from 2.4 MMbbl/d in 2012 to about 3.0 MMbbl/d in 2030, then remains level after 2030, as growth in natural gas production slows.

Domestic ethanol production remains relatively flat, as consumption of motor gasoline decreases and the penetration of ethanol is slowed by the limited availability of flex-fuel vehicles and retrofitted filling stations. Biodiesel production is also constant throughout the projection on the assumption that the U.S. Environmental Protection Agency (EPA) will indefinitely continue the current requirement of 1.28 billion gallons per year under the RFS.

Other biomass-to-liquids production, excluding ethanol and biodiesel, increases by 32,200 bbl/d from 2012 to 2040. However, neither gas-to-liquids (GTL) nor coal-to-liquids (CTL) contributes to domestic liquids production in the Reference case because of the risks associated with their high capital costs, long construction leadtimes, and the possibility that liquids from CTL facilities will not remain price-competitive with crude oil over the lifetimes of the facilities.

## U.S. crude oil production rates depend on resource availability and production costs

Figure MT-52. Total U.S. crude oil production in three cases, 1990-2040 (million barrels per day)




Projections of U.S. tight oil production are uncertain, because large portions of the known formations have little or no production history, and because technology improvements could increase well productivity while reducing drilling, completion, and production costs. The High and Low Oil and Gas Resource cases illustrate the potential impacts of changes in the Reference case assumptions regarding technology advances and the resource size and quality.

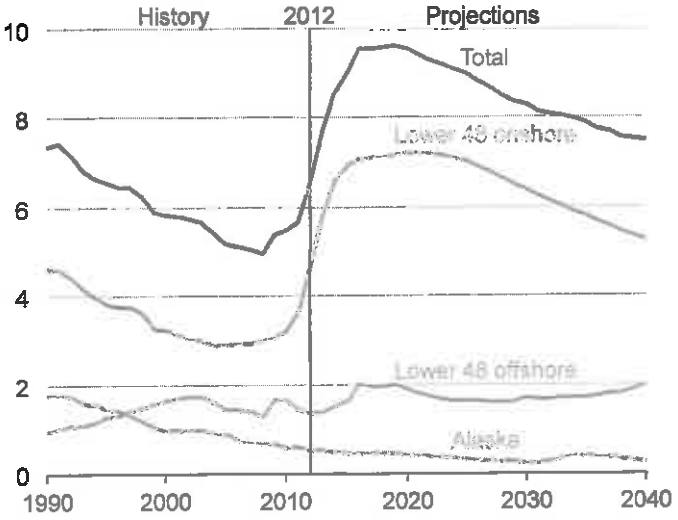
The High Oil and Gas Resource case assumes more onshore lower 48 tight resources than in the Reference case, as a result of higher EUR per well and closer well spacing; tight oil development in Alaska; more offshore resources in Alaska and the lower 48 states; and more rapid technology improvements over the long term.

In the High Oil and Gas Resource case, higher well productivity reduces development and production costs per unit, resulting in more and earlier development of oil and gas resources than in the Reference case (Figure MT-52). U.S. crude oil production in the High Oil and Gas Resource case reaches 13.3 MMbbl/d in 2036, compared with an earlier and lower projected high point of 9.6 MMbbl/d in 2019 in the Reference case. Cumulative production in the High Oil and Gas Resource case is about 125 billion barrels—compared to about 90 billion barrels in the Reference case—from 2012 to 2040.

In the Low Oil and Gas Resource case, which assumes lower estimates of tight resources than in the Reference case, crude oil production plateaus at an earlier and lower projected high of 9.2 MMbbl/d in 2016 before declining. With production of tight oil continuing to decline through 2040 in the Low Oil and Gas Resource case, cumulative crude oil production from 2012 to 2040 is 10% lower than in the Reference case, at about 81 billion barrels.

## Lower 48 onshore tight oil development spurs increase in U.S. crude oil production

Figure MT-53. Domestic crude oil production by source in the Reference case, 1990-2040 (million barrels per day)



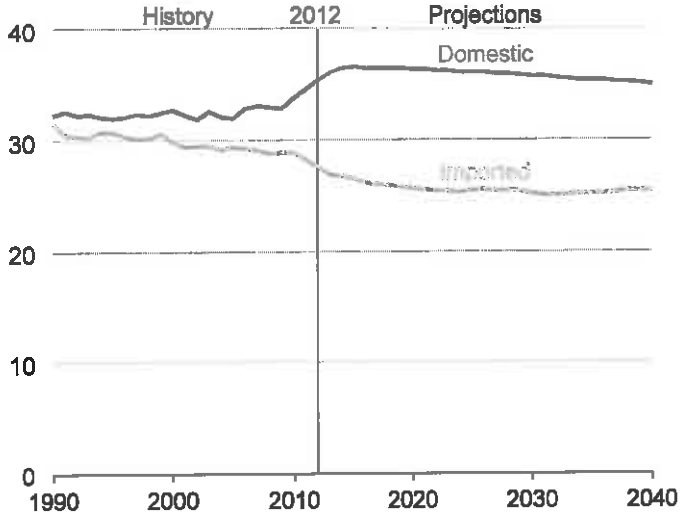

U.S. crude oil production grows from 2012 through 2019 in the Reference case, before peaking at more than 9.6 million barrels per day (MMbbl/d)—about 3.1 MMbbl/d above the 2012 total and close to the historical high of 9.6 MMbbl/d in 1970 (Figure MT-53). The growth in lower 48 onshore crude oil production is primarily a result of continued development of tight oil resources in the Bakken, Eagle Ford, and Permian Basin formations. Tight oil production increases to a peak of 4.8 MMbbl/d from 2018 through 2021 and then declines to about 3.2 MMbbl/d in 2040 (0.9 MMbbl/d higher than the 2012 total) as high-productivity areas, or sweet spots, are depleted. There is considerable uncertainty about the expected peak level of tight oil production, because ongoing exploration, appraisal, and development programs expand operator knowledge about producing reservoirs and could result in the identification of additional tight oil resources.

Crude oil production using carbon dioxide-enhanced oil recovery ($CO_2$-EOR) increases after 2017—when oil prices rise, and as output from the more profitable tight oil deposits begins declining and affordable anthropogenic sources of carbon dioxide ($CO_2$) become available—to 0.7 MMbbl/d in 2040. The rate of the increase is slower over the last five years, when production is limited by reservoir quality and $CO_2$ availability. From 2013 through 2040, cumulative crude oil production from $CO_2$-EOR projects totals 5.2 billion barrels.

Lower 48 offshore oil production varies between 1.4 MMbbl/d and 2.0 MMbbl/d over the projection period. Toward the end of the period, the pace of exploration and production activity quickens, and new large development projects, associated predominantly with discoveries in the deepwater and ultra-deepwater portions of the Gulf of Mexico, are brought on stream. New offshore oil production from the Alaska North Slope partially offsets the decline in production from onshore North Slope fields.

## Domestic production of tight oil leads to lower imports of light sweet crude oil

Figure MT-54. Average API gravity of U.S. domestic and imported crude oil supplies in the Reference case, 1990-2040 (degrees API)



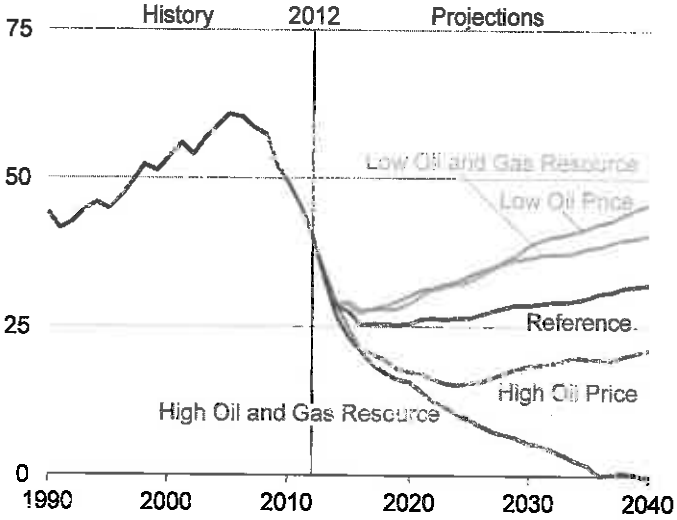

API gravity is a measure of the specific gravity, or relative density, of a liquid, as defined by the American Petroleum Institute. It is expressed in degrees, where a higher number indicates a lower density. Refineries generally process a mix of crude oils with a range of API gravities to optimize refinery operations. Over the past 15 years, the API gravity of crude oil processed in U.S. refineries has averaged between 30 and 32 degrees. As U.S. refiners run more domestic light crude oil produced from tight formations, they need less imported light crude to maintain an optimal API gravity. With increasing U.S. production of light crude oil in the AEO2014 Reference case, the average API gravity of crude oil imports declines from 27.6 degrees in 2012 to 25.6 degrees in 2040 (Figure MT-54).

With total crude oil imports declining in the Reference case, imports of light crude oil are reduced, resulting in a heavier slate of imported crude oil. The growing share of heavier crude oil imports continues through 2025 before stabilizing. The increase in demand for diesel fuel in the Reference case, from 3.4 MMbbl/d in 2012 to 4.3 MMbbl/d in 2040, combined with a steady increase in exports of distillate fuel oil from 1.0 MMbbl/d to 1.1 MMbbl/d over the same period, increases the value of heavier crudes in U.S. refineries.

The large increase in domestic production of light crude oil and the increase in imports of heavier crude oils have prompted significant investments in the midstream infrastructure for crude oil, including pipelines that will bring higher quantities of light sweet and heavy sour crudes to petroleum refineries along the U.S. Gulf Coast. In addition, significant investments have been made to move crude oil by rail to refineries on the East Coast, West Coast, and Gulf Coast.

## Increasing U.S. oil supply reduces net imports of petroleum and other liquid fuels

Figure MT-55. Net import share of U.S. petroleum and other liquid fuels consumption in five cases, 1990-2040 (percent)




The net crude oil and product imports share of U.S. petroleum and other liquid fuels consumption grew from the mid-1980s to 2005 but has fallen steadily since 2005 (Figure MT-55). Because each barrel of U.S. crude oil production displaces a barrel of imported crude oil, the outlook for net petroleum and other liquid fuel imports in the High and Low Oil Price and High and Low Oil and Gas Resource cases depends on U.S. oil production.

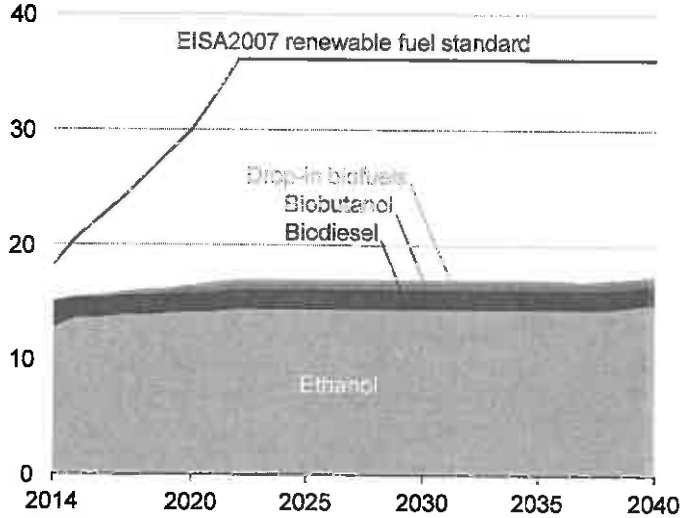
The net import share of U.S. petroleum and other liquid fuels consumption declines from 2012 through 2023 in the AEO2014 Reference case, largely because of projected growth in tight oil production. The net import share declines to 25% in 2019, coinciding with a peak in U.S. oil production of 9.6 MMbbl/d, then increases to 32% in 2040 after domestic oil production declines.

Higher oil prices encourage more rapid and extensive oil resource development. In the High Oil Price case, the share of domestic consumption accounted for by imports of petroleum and liquid fuels drops to 15% in 2023, then grows to 21% in 2040. The opposite occurs in the Low Oil Price case, with the petroleum and other liquids imports share of domestic consumption rising after 2016, to 46% in 2040.

In the High Oil and Gas Resource case, improvements in oil production technology beyond those in the Reference case, along with 1% annual growth in estimated ultimate recovery (EUR), lead to higher U.S. crude oil production. In 2036, U.S. crude production peaks at 13.3 MMbbl/d, and net U.S. imports of crude oil and petroleum products fall to virtually zero, where they remain through 2040. The Low Oil and Gas Resource case uses the same production technology assumptions as the Reference case but assumes a 50% lower EUR. As in the Low Price case, net imports begin to rise in 2016 and increase to 40% of U.S. consumption in 2040.

## U.S. consumption of biofuels grows but does not approach EISA2007 applicable volumes

Figure MT-56. EISA2007 Renewable Fuels Standard credits earned by fuel type in the Reference case, 2012-40 (billion credits)



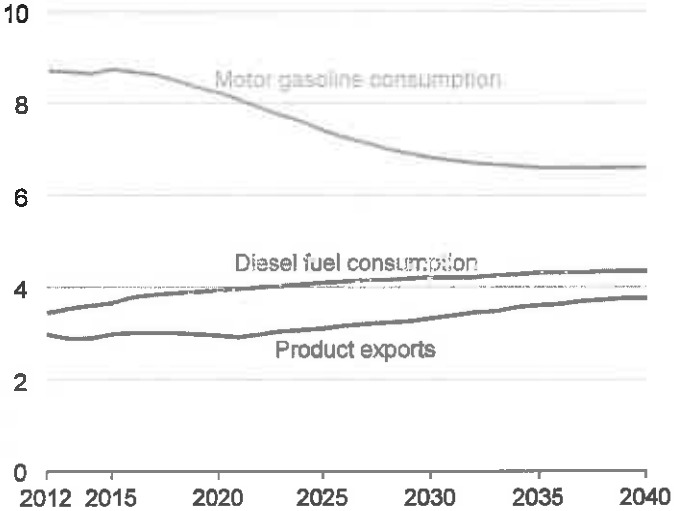

Consumption of biofuels grows in the AEO2014 Reference case but falls well short of the Energy Independence and Security Act of 2007 (EISA2007) RFS target [13] of 36 billion ethanol gallon equivalents in 2022 (Figure MT-56), largely because of a decline in gasoline consumption as a result of newly enacted corporate average fuel economy (CAFE) standards and updated expectations for sales of vehicles capable of using E85. Demand for motor gasoline ethanol blends (E10 and E15) falls from 8.7 MMbbl/d in 2012 to 7.9 MMbbl/d in 2022, while total biofuels consumption rises from 14 billion gallons to 16 billion ethanol gallons equivalent over the same period.

The current and projected vehicle fleets are not equipped to use ethanol's increased octane content relative to gasoline. As a result, the retail price of E85 must be less than 79% of the motor gasoline price for E85 to gain significant market share. In the Reference case, with the lowest ratio of E85 to gasoline prices at 77% in 2022, market penetration of E85 is modest, and the RFS program does not provide sufficient incentives to promote significant new ethanol production capacity.

In the Reference case, as gasoline demand continues to drop and E85 consumption levels off, total ethanol consumption grows to about 14 billion gallons in 2022 and remains there until late in the projection. Consumption of biodiesel falls in the near term, as production of drop-in biofuels grows. Domestic consumption of drop-in biofuels grows from 135 million ethanol gallons equivalent in 2014 to 316 million ethanol gallons equivalent in 2019. Biobutanol consumption rises after 2019, to about 516 million gallons in 2040.

## A variety of factors leads to a shift in consumption from motor gasoline to diesel fuel

Figure MT-57. Motor gasoline consumption, diesel fuel consumption, and petroleum product exports in the Reference case, 2012-40 (million barrels per day)



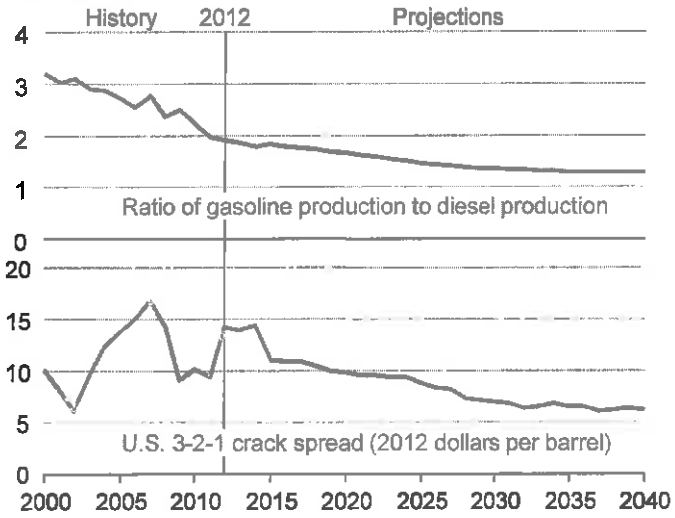

Based on the NHTSA and EPA GHG and CAFE standards, EIA projects that new light-duty vehicles (LDVs) will average approximately 47 mpg in 2025. These efficiency standards contribute to a decline in consumption of motor gasoline, while increases in vehicle miles traveled (VMT) and renewable fuel standards (RFS) lead to an increase in consumption of diesel fuel and ethanol in the Reference case. As a result of rising fuel economy standards, motor gasoline consumption by LDVs falls over the projection period while total VMT increase.

The decrease in gasoline consumption, combined with growth in diesel consumption, leads to a shift in refinery outputs and investments. Motor gasoline consumption and diesel fuel consumption trend in opposite directions in the Reference case, with consumption of diesel fuel increasing by approximately 0.9 MMbbl/d from 2012 to 2040, while finished motor gasoline consumption falls by 2.1 MMbbl/d (Figure MT-57). New refinery projects are expected to focus on shifting production from gasoline to distillate fuels to meet the growing demand for diesel.

As a result of refinery economics and slower growth in domestic demand, no new petroleum refinery crude unit capacity is built in the Reference case, except for plants already under construction in 2012. Further, the refining system has at least 2 MMbbl/d of excess crude oil capacity beginning in 2015. In addition to meeting domestic demand, refineries continue to export finished products to international markets throughout the projection. Beginning in 2016, gross exports of total finished petroleum products increase to 3.0 MMbbl/d for the first time, and in 2040 exceed 3.7 MMbbl/d (Figure MT-57). The United States became a net exporter of finished petroleum products in 2011, and in the Reference case, it remains a net exporter through 2040.

## Shifts in demand for liquid fuels change petroleum refinery yields and crack spreads

Figure MT-58. U.S. refinery gasoline-to-diesel production ratio and crack spread in the Reference case, 2000-40




The transition to lower gasoline and higher diesel production has a significant effect on petroleum refinery operations in the AEO2014 Reference case, with the ratio of gasoline to diesel production declining from 1.8 in 2012 to below 1.3 in 2040 (Figure MT-58). In response to the drop in gasoline demand, refinery utilization of fluid catalytic cracking (FCC) units falls from 67% in 2012 to about 55% in 2040. In contrast, with diesel production increasing, installed distillate and gas oil hydrocracking capacity grows from about 2.2 MMbbl/d in 2012 to 2.9 MMbbl/d in 2040, indicating a shift from FCC feeds to hydrocrackers to maximize diesel production.

Refinery profitability is a function of crude input costs, processing costs, and market prices for the end products. Profitability often is estimated from the crack spread, which is the difference between the price of crude oil and the price of finished products—typically, gasoline and distillate fuel. The 3-2-1 crack spread estimates the profitability of processing three barrels of crude oil to produce two barrels of gasoline and one barrel of distillate. In the Reference case, the 3-2-1 crack spread (based on Brent crude oil prices) declines from $14/barrel in 2012 to about $6/barrel in 2040 (2012 dollars). In the current environment, the gross margin would vary with the differential between Brent and Gulf Coast light crude oil prices.

To relate the gross margin to refinery profitability, operating costs for specific refineries also must be deducted. As product demands shift, petroleum refineries may alter the ratio of gasoline to diesel production. A 5-3-2 crack spread estimates the profitability of processing five barrels of crude oil into three barrels of gasoline and two barrels of distillate, more consistent with the 1.3 gasoline-to-diesel production ratio after 2035.