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Financial Challenges of Operating Nuclear Power Plants in the United States

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December 14, 2016

Congressional Research Service
7-....
www.crs.gov
R44715

Summary

Some of the 60 operating nuclear power plants (comprising 99 nuclear reactors) in the United States have experienced financial stress in recent years due to a combination of low wholesale electricity prices and escalating costs. Six nuclear reactors have permanently shut down during the past five years, and 19 others have announced their intention to close or have been identified as “at-risk” of closure by financial consultants and ratings agencies.

Generally, U.S. nuclear plants are located in one of two market areas: (1) competitive—where the value of electricity fluctuates based on supply-side price offers that are generally a function of fuel (e.g., natural gas) costs and demand-side price bids, and (2) cost-of-service—where the value of electricity is set at a rate based on regulator-approved costs, operating expenses, and a reasonable investment return. Most of the U.S. plants considered vulnerable to shut down before expiration of their operating licenses are “merchant plants” that sell all or most of their power into competitive wholesale power markets. The price paid to merchant plants for electric power varies by location and is influenced by the price-setting fuel (usually natural gas and coal), transmission congestion, and other factors. Wholesale electricity prices in certain locations have fallen and electricity sales revenue may be below the fuel and operating and maintenance (O&M) costs of some plants, not considering capital expenditures that may also be incurred.

CRS analysis of third-party data indicates that 19 of 33 power plants operating in competitive power markets may incur fuel and O&M costs that exceed electricity revenues for each plant in 2016. However, this number declines to seven in 2017 due to rising forward electricity prices as reported by Bloomberg. While merchant generators do have other revenue sources (i.e., capacity payments where available, power purchase agreements, and hedging positions) and additional costs (e.g., capital), CRS was not able to locate plant-specific information about these revenues and costs that would allow for a holistic financial assessment at the plant level.

The nuclear power industry and its supporters have proposed that Congress take action to prevent currently operating U.S. reactors from shutting down before their licenses expire. Supporters contend that nuclear power should be valued as a domestic source of highly reliable, low-carbon electricity. However, opponents contend that nuclear power suffers from too many drawbacks and that federal incentives should focus instead on renewable energy and efficiency. Nuclear power plants annually provide about 20% of total U.S. electricity generation.

To date, all of the policy action related to financial support for existing nuclear plants has been at the state level. New York has implemented a Clean Energy Standard (CES) that includes payments to qualified nuclear power plants in the state starting at approximately $17 per megawatt-hour in 2017. The CES has been challenged on legal grounds. A similar program was recently approved by the Illinois legislature, and Ohio has also considered nuclear support.

Since each nuclear power plant is subject to a unique combination of financial variables, federal-level incentives are challenged because some nuclear plants are expected to continue operating without federal financial support. Should Congress choose to debate financial incentives for existing nuclear plants, several options may be considered. Tax incentives based on capital investment or electricity production could potentially provide financial support for existing nuclear plants. Establishing a carbon price—carbon tax, cap-and-trade, emissions regulations—could also provide some financial assistance to nuclear power, depending on how a carbon price mechanism was designed and implemented. Finally, Congress could authorize and require the federal government to enter into power purchase agreements with nuclear power plants that would provide a guaranteed price for nuclear-generated electricity. Additionally, the nuclear

industry has been advocating that the Federal Energy Regulatory Commission (FERC) institute changes to electricity price formation in competitive power markets.

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Introduction

Recent and planned nuclear reactor closures have raised questions about the future of nuclear power in the United States and its potential contribution to the U.S. electricity mix. The nuclear power industry and its supporters have proposed that Congress take action to prevent the shutdown of currently operating U.S. reactors before the expiration of their operating license. Supporters contend that nuclear power should be valued as a domestic source of highly reliable, low-carbon electricity. However, opponents contend that nuclear power suffers from too many drawbacks (e.g., safety risks) and that federal incentives should focus instead on renewable energy and efficiency.

There are currently 60 operating nuclear power plants in the United States comprising 99 reactors and representing 99,316 Megawatts of generating capacity—nearly 10% of existing utility-scale generating capacity, and approximately 20% of total power generation.[1] Generally, U.S. nuclear plants are located in one of two market types: (1) competitive—where the value of electricity fluctuates based on supply-side price offers that are generally a function of fuel (e.g., natural gas) costs and demand-side price bids, and (2) cost-of-service—where the value of electricity is set at a rate based on regulator-approved costs, operating expenses, and a reasonable investment return.

Some nuclear plants located in competitive power markets are subject to full or partial rate regulation, which reduces financial risk associated with fluctuating electricity prices. Access to competitive wholesale power market prices can result in regulatory bodies deciding that early nuclear plant retirement is in the best interest of rate payers based on projected electricity prices.[2] Other plants located in competitive power markets operate on a "merchant" basis, where electricity prices and revenues are subject to commodity price fluctuations and supply/demand dynamics. Merchant nuclear power plants are the focus of this report.

Competitive power markets are managed by either a Regional Transmission Organization (RTO) or an Independent System Operator (ISO), which operates electricity and capacity markets that determine revenues for nuclear, and other, power generators.[3] Unlike cost-of-service market areas—where generators have electricity price rates that are approved and periodically revised by a state utility commission—competitive power markets are subject to electricity price volatility that results from supply and demand fundamentals as well as fuel (e.g., natural gas and coal) costs for the marginal price-setting generators. While generators operating in cost-of-service market areas are not immune to fuel competition, to date nuclear power plants that have announced early closure or have been identified by financial consultants and ratings agencies as "at-risk" of closure are located in competitive market areas.

U.S. nuclear power plants operating in competitive power markets are in an era of challenging economic conditions—increasing operating costs and low wholesale power prices in some locations—that create uncertainty regarding the future of some plants. Six reactors have permanently shut down during the past five years; 10 reactors—at eight plant sites—have announced, since 2010, their intent to close—nine in the past two years[4] (see **Figure 1**); and 10

[1] Generating capacity is reported as net summer capacity; see Energy Information Administration, *Monthly Nuclear Utility Generation (MWh) by State and Reactor*, August 2016.

[2] The Ft. Calhoun reactor shutdown in Nebraska, discussed later in this report, is an example of a fully rate-regulated nuclear plant located in a competitive power market. Ft. Calhoun regulators decided that early shutdown of the reactor was in the best financial interest of the rate payers.

[3] For more information about RTOs and ISOs, see the ISO/RTO Council website, http://www.isorto.org/about/default.

[4] Nine of the 10 reactors announced their intent to close in the past two years. One, Oyster Creek, announced in 2010 (continued...)

have been identified by consultants and ratings agencies as "at-risk" of closing prior to the expiration of their operating licenses. In total, these plants represent 22,078 Gigawatts of generating capacity, which is roughly 20% of the current nuclear power fleet.[5]

Of the 10 power reactors that have announced their intent to close, some operate under full or partial rate regulation—they receive a set price for electricity sales—and some operate solely as merchant power plants—they are subject to the price dynamics of competitive power markets. However, the one common link among the reactors that have announced their intent to close is that they are located in competitive power markets (**Figure 1**).[6] Because they are subject to wholesale power price dynamics, merchant generators operating in competitive power markets are the focus of the economic discussion included in this report.

This report provides background on the evolution of nuclear power in the United States, discusses recent and announced plant closures, explains the economic conditions creating financial challenges for merchant nuclear power plants, and presents policy considerations associated with the future of existing nuclear power plants.

Caveats and Limitations

The financial situation for each nuclear power plant is unique. Operating costs, expected capital expenditures, wholesale power prices, capacity payments, hedging exposure, power purchase agreements (PPAs), and full or partial regulated rate structures are financial components that are plant and location specific. Nevertheless, much of the economic and financial information presented in this report is generalized in order to illustrate the cost and pricing trends across the entire industry. While some plant-by-plant analysis is referenced and contained in this report, there are important data assumptions that should be noted. To date, CRS has not been able to locate or aggregate a comprehensive data set that would allow for a plant-by-plant analysis that accurately reflects all financial variables.

(...continued)

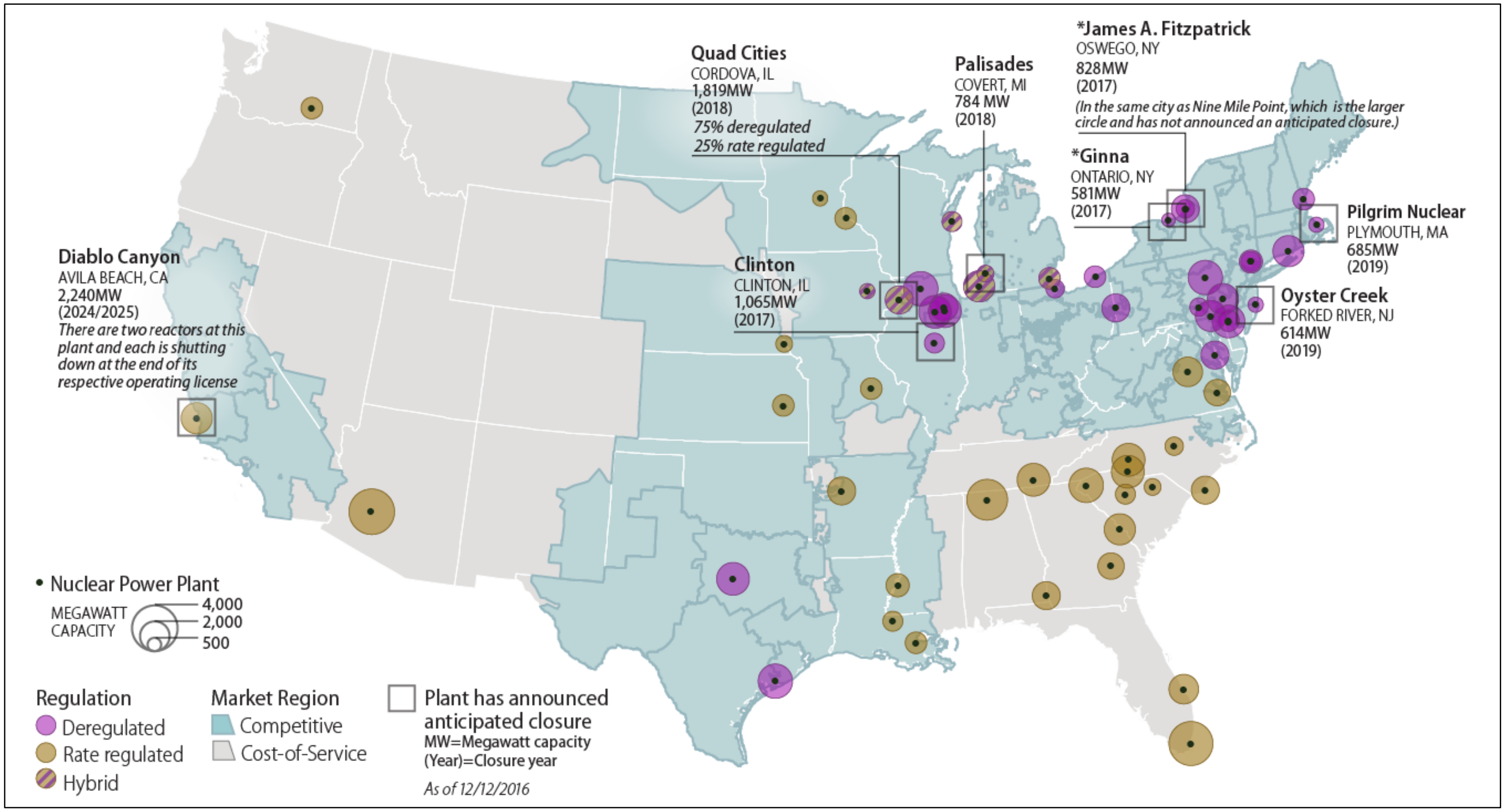
its intent to close.

[5] See **Table 2**. Calculation is based on net summer capacity as reported by the Energy Information Administration.

[6] There are several nuclear power plants that are located in the footprint of a competitive market but are rate-regulated by a state entity. These plants have guaranteed rates for electricity generation and are thus not subject to wholesale price dynamics. In **Figure 1**, these plants are located in the competitive power market area (green shaded area) and are indicated by a yellow dot (rate regulated).

Figure 1. Operational Nuclear Power Generation Facilities in the United States

Announced Plant Closures Indicated by Labels



Source: Map by CRS using data from S&P Global Platts geospatial data layers, 2016; and Esri Data & Maps, 2014.

Notes: The eight plant sites labeled on this map represent 10 nuclear reactors. Diablo Canyon and Quad Cities are both two-reactor sites. No nuclear power plants are located in Alaska or Hawaii.

* The Fitzpatrick and Ginna plants in New York may continue to operate based on successful implementation of the New York Clean Energy Standard, which includes Zero Emission Credits (ZECs) for at-risk nuclear facilities. Quad Cities and Clinton plants located in Illinois may also continue operating as a result of the state legislature passing a similar ZEC program in December 2016.

Overview of U.S. Nuclear Power Generation

Commercial-scale nuclear power generation in the United States was inaugurated in 1957 by the startup of the Shippingport reactor in western Pennsylvania. Built by the U.S. Atomic Energy Commission (AEC) and operated by Duquesne Light Company, the relatively small (60 Megawatt) power plant was not considered economically viable.[7] However, Shippingport paved the way for additional demonstration reactors that were rapidly scaled up in generating capacity to provide a viable alternative to power plants fired by fossil fuels.

Harnessing the tremendous energy potential of nuclear fission had been a major federal goal since the development of nuclear weapons during World War II. Post-war policymakers widely anticipated that nuclear power plants could generate much or most of the power that would be needed to satisfy the nation's rapidly escalating demand for electricity, particularly if plutonium and uranium from spent nuclear fuel were recycled for use in advanced fast-neutron reactors. It was also hoped that the widespread adoption of nuclear power would mitigate volatile and rising fossil fuel prices, growing dependence on foreign oil, and air pollution.

The legal framework for the U.S. nuclear power industry was established by the Atomic Energy Act of 1954 (AEA), which authorized the private sector to own and operate nuclear facilities under AEC licensing. To encourage private-sector adoption of the new and potentially hazardous technology, Congress enacted the Price-Anderson Act as an amendment to the AEA in 1957, establishing a special public liability system for reactor operators and suppliers.[8]

Shippingport and other small, early commercial nuclear plants were constructed with subsidies under the AEC's Power Reactor Demonstration Program. Beginning in 1963, reactor suppliers began selling substantially larger units—around 500 megawatts and above—on a "turnkey"[9] basis to electric utilities. By 1965, plants as large as 1,100 megawatts were being ordered by utilities under a non-turnkey basis, with contract terms similar to those of non-nuclear power plants.[10] Rising coal prices and the apparently improved economics of larger reactors prompted electric utilities to order 20 new nuclear units in 1966 and 31 in 1967—only a decade after the startup of Shippingport. Reactor orders continued at a strong pace through 1971 and then jumped to 38 in 1972 and 41 in 1973.[11]

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[7] Hewlett, Richard G., and Jack M. Holl, *Atoms for Peace and War, 1953-1961*, University of California Press, 1989, p. 421. Shippingport's total per-megawatt capital costs were estimated at about 10 times those of a conventional generating unit of that time. The Shippingport plant constituted a major milestone in the U.S. government's nuclear reactor development efforts that began during World War II and continue today. For a description of historical federal energy research and development expenditures, see CRS Report RS22858, *Renewable Energy R&D Funding History: A Comparison with Funding for Nuclear Energy, Fossil Energy, and Energy Efficiency R&D*, by (name redacted)

[8] Section 170 of the Atomic Energy Act of 1954, 42 U.S. C. § 2210—Indemnification and limitation of liability. Under the Price-Anderson Act, liability for damages to the public from radioactive releases from nuclear power plants is channeled to the operator of the power plant involved in a release. The plant operator's liability is limited to the amount of available insurance plus mandatory payments by all nuclear utilities. See "Nuclear Accident Liability" in CRS Report RL33558, *Nuclear Energy Policy*, by (name redacted)

[9] Under "turnkey" contracts, reactor manufacturers provided utilities with completed nuclear power plants that were ready to operate, often at a fixed price. Overall, reactor manufacturers lost money on the turnkey contracts and stopped offering them after 1966. See Burness, H. Stuart, et al., "The Turnkey Era in Nuclear Power," *Land Economics*, May 1980.

[10] Perry, Robert, et al., *Development and Commercialization of the Light Water Reactor, 1946-1976*, June 1977, Rand Corporation, R-2180, NSF, p. xi.

[11] Nuclear Energy Institute, *Historical Profile of U.S. Nuclear Power Development*, 1994 Edition.

However, the wave of reactor orders then receded as dramatically as it had begun. Surging energy prices resulting from the Arab oil embargo in 1973-1974 dramatically slowed the growth of U.S. electricity demand, and it became apparent that electric utilities had ordered too much generating capacity of all types. In addition, nuclear power plant construction costs were sharply escalating, interest rates were rising, and greater safety expenditures were required after the 1979 core-melt accident at Three Mile Island 2.[12] All reactors ordered from 1974 through 1978 were subsequently canceled, and no further reactor orders were placed in the United States until 2008, when contracts were signed for four new units now being built in Georgia and South Carolina. Most of the reactors ordered from 1971 through 1973 were also canceled, for a total of 126 cancellations.[13]

In addition to the cancellations, the lower-than-expected growth in electricity demand led electric utilities to slow the construction of many reactors that had not been canceled, stretching their completion into the 1980s and 1990s, and to 2016 in the case of one reactor, Watts Bar 2.[14] Of the 256 reactor orders placed through the 1970s, 134 reactors, including the early AEC demonstration plants, ultimately were completed and placed into service.

Throughout the history of the U.S. nuclear power program, reactors have permanently shut down for a variety of reasons. Many of the small, early AEC reactors were not necessarily expected to operate for a long time, and nine of them had been permanently closed by the late 1970s. Three Mile Island 2, a nearly new reactor, closed in 1979 after its accident. Four reactors were permanently closed during the 1980s, including the Shoreham plant on Long Island, NY, which had never begun full-power operation. During the 1990s, 10 reactors shut down, including the large, two-unit Zion plant in Illinois.

Rising natural gas prices in the early 2000s significantly improved the economics of nuclear power, because they made gas-fired electric generation more expensive while nuclear generation costs remained comparatively low (discussed in detail later in this report). Existing reactors were no longer being closed, and the first U.S. license applications for new reactors since 1978 were filed with the Nuclear Regulatory Commission (NRC, the regulatory successor to the AEC)[15] beginning in 2007. However, gas prices fell sharply after 2009 and have remained low, primarily because of strong production of domestic shale gas. Six reactors have permanently shut down since the beginning of 2013, and additional closures have been announced.

The current economic situation has clouded the outlook for new U.S. reactors. NRC has issued construction and operating licenses to seven new reactors and is currently considering applications for seven more.[16] However, except for the four units in Georgia and South Carolina that are now under construction, no commitments have been made to build any others.

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[12] On March 28, 1979, a pressure relief valve in Three Mile Island unit 2 stuck open, allowing reactor cooling water to escape. Although control rods halted the nuclear chain reaction as designed, the nuclear fuel rods in the reactor core continued to generate heat through radioactive decay. A substantial portion of the fuel rods melted before reactor operators restored cooling water to the reactor core.

[13] Nuclear Regulatory Commission, NRC Datasets, "Cancelled U.S. Commercial Nuclear Power Reactors," updated July 1, 2016, http://www.nrc.gov/reading-rm/doc-collections/datasets/, and Nuclear Energy Institute, *Historical Profile of U.S. Nuclear Power Development*, 1994 Edition.

[14] Watts Bar 2 had been ordered in 1970, but construction was suspended from 1985 to 2007. See NRC, "History of Watts Bar Unit 2 Reactivation," October 28, 2015, http://www.nrc.gov/info-finder/reactors/wb/watts-bar/history.html.

[15] Energy Reorganization Act of 1974, P.L. 93-438.

[16] Nuclear Regulatory Commission, "New Reactor Licensing Applications," June 20, 2016, http://www.nrc.gov/reactors/new-reactors/new-licensing-files/new-rx-licensing-app-legend.pdf.

Table 1. History of U.S. Power Reactor Orders, Startups, and Shutdowns

Number of Reactors

Years	Orders	Cancellations	Startups	Shutdowns	Operating at end of decade
1950s	16	0	3	0	3
1960s	87	0	21	8	16
1970s	153	57	58	7	67
1980s	0	58	48	4	111
1990s	0	5	3	10	104
2000s	8	0	0	0	104
2010s	0	6	1	6	99
Total	**264**	**126**	**134**	**35**	

Source: Nuclear Energy Institute, Nuclear Regulatory Commission

Notes: 264 total orders minus 126 cancellations = 138 reactors that were not canceled. Of those 138, 4 are still under construction, leaving 134 that have started up. Of the 134 startups, 35 have shut down, leaving 99 currently operating. "2010s" are through November 2016.

As shown in **Table 1**, of the 134 commercial reactors that have started operating since the beginning of the U.S. nuclear power program, 35 have permanently closed, leaving 99 currently operating and 4 under construction. The 99 operating U.S. commercial power reactors are located in 30 states at 60 plant sites.[17] Nuclear power plants annually provide about 20% of total U.S. electricity generation, most recently 19.5% in 2015. Nuclear power accounted for 61.6% of U.S. "zero carbon" electricity generation in 2015.[18]

Under the Atomic Energy Act, nuclear power reactors are licensed to operate for 40 years and are eligible for 20-year license renewals thereafter. Because about half of U.S. reactors started operating in the 1970s or earlier, the licenses of much of the reactor fleet would have expired by now without renewal. As of July 2016, according to NRC, 80 of the 99 currently operating reactors have received 20-year license renewals, and 12 additional renewal applications are under review.[19] The 20-year renewals, allowing 60 years of operation, would extend the licenses of most current reactors through the 2030s and of almost all the remainder through the 2040s.[20] Further 20-year renewals are also possible under the AEA, extending plant lives to 80 years or longer.

Actual, Planned, and Possible Reactor Closures

After experiencing no commercial reactor closures during the first decade of the 21st century, the U.S. nuclear power industry has seen six reactors retire during the past five years, with at least 19

[17] Nuclear Regulatory Commission, NRC Datasets, "Commercial Nuclear Power Reactors—Operating Reactors," July 26, 2016, http://www.nrc.gov/reading-rm/doc-collections/datasets/.

[18] Energy Information Administration, "Net Generation for All Sectors, Annual," http://www.eia.gov/electricity/data/browser/. Excludes biomass. "Zero carbon" and "zero emissions" refers to direct emissions from power generation.

[19] Nuclear Regulatory Commission, "Reactor License Renewal" and "Fact Sheet on License Renewal," http://www.nrc.gov/reactors/operating/licensing/renewal.html.

[20] Nuclear Regulatory Commission, *Information Digest, 2016–2017*, NUREG-1350, Volume 28, Appendix G, "Commercial Nuclear Power Reactor Operating Licenses—Expiration by Year, 2013–2049," http://www.nrc.gov/docs/ML1624/ML16245A069.pdf.

more considered to be at risk of closure by their owners or major credit rating agencies (see **Table 2**). However, New York and Illinois have recently taken action to keep seven of the at-risk reactors operating.

These actual, announced, and potential nuclear plant shutdowns fall into several broad and sometimes overlapping categories. The fundamental problem for most of the at-risk plants is that their revenues depend almost entirely on regional wholesale electricity markets, where prices have been insufficient to cover their costs. Some plants, such as Quad Cities, have relatively low operating and maintenance costs, but still cannot bring in sufficient revenue in their regional markets, because of a combination of oversupply, transmission congestion, and other local factors. Several single-unit nuclear plants, which generally have higher costs per megawatt-hour, are having trouble competing even in markets with relatively high power prices. For example, the Pilgrim plant in the New England market is reportedly receiving revenues that are insufficient to cover fuel, operating and maintenance, and capital expenditures, as discussed below.[21]

The chronic inability to cover costs during routine operations is not the only source of nuclear plant retirement risk: Marginally economic plants can be vulnerable to closure because of major repairs, capital expenditures, prolonged shutdowns, and other non-routine events. Merchant plants may be especially vulnerable, but such occurrences can even prompt the retirement of rate-regulated plants, as seen at San Onofre and Crystal River. Non-revenue factors, such as concerns about seismic safety at Diablo Canyon, can also contribute to nuclear plant closures.

Table 2. Actual, Announced, and Potential U.S. Commercial Reactor Shutdowns Since 2000

(By Shutdown Date)

Reactor	State	Shutdown Date	Net Summer Generating Capacity (Megawatts)	Start-up Year	Major Factors Contributing to Shutdown
Actual Shutdowns					
Crystal River 3	Florida	Feb. 2013	860	1977	Cost of major repairs to reactor containment
Kewaunee	Wisconsin	May 2013	566	1974	Operating losses
San Onofre 2	California	June 2013	1,070	1983	Cost of replacing new steam generators
San Onofre 3	California	June 2013	1,080	1984	Cost of replacing new steam generators
Vermont Yankee	Vermont	Dec. 2014	620	1972	Operating losses
Fort Calhoun	Nebraska	Oct. 2016	479	1973	Operating losses
Announced Shutdowns					
FitzPatrick	New York	Jan. 2017	828	1976	Operating losses; may continue running with state Zero Emission Credits

[21] Rorke, Catrina, *Where Have All the Nuclear Plants Gone?*, R Street Institute, Policy Study No. 70, October 2016, p. 5, http://www.rstreet.org/policy-study/where-have-all-the-nuclear-plants-gone/.

Reactor	State	Shutdown Date	Net Summer Generating Capacity (Megawatts)	Start-up Year	Major Factors Contributing to Shutdown
Ginna	New York	March 2017	581	1970	Operating losses; may continue running with state Zero Emission Credits
Clinton	Illinois	June 2017	1,065	1987	Operating losses; may continue running with state Zero Emission Credits
Quad Cities 1	Illinois	June 2018	908	1972	Operating losses; may continue running with state Zero Emission Credits
Quad Cities 2	Illinois	June 2018	911	1972	Operating losses; may continue running with state Zero Emission Credits
Palisades	Michigan	Oct. 2018	784	1971	Operating losses, end of power purchase agreement
Pilgrim	Massachusetts	May 2019	685	1972	Operating losses, rising capital expenditures
Oyster Creek	New Jersey	Dec. 2019	614	1969	Agreement with state to avoid building cooling towers
Diablo Canyon 1	California	Nov. 2024	1,122	1985	Settlement with labor and environmental groups
Diablo Canyon 2	California	Aug. 2025	1,118	1986	Settlement with labor and environmental groups
Reactors Identified at Risk of Closure					
Beaver Valley 1	Pennsylvania	NA	892	1976	Operating losses
Beaver Valley 2	Pennsylvania	NA	885	1987	Operating losses
Byron 1	Illinois	NA	1,164	1985	Operating losses
Byron 2	Illinois	NA	1,136	1987	Operating losses
Davis-Besse	Ohio	NA	894	1978	Operating losses
Nine Mile Point 1	New York	NA	630	1969	Operating losses; may continue running with state Zero Emission Credits
Nine Mile Point 2	New York	NA	1,143	1987	Operating losses; may continue running with state Zero Emission Credits
Perry	Ohio	NA	1,240	1987	Operating losses
Three Mile Island 1	Pennsylvania	NA	803	1974	Operating losses

Source: Nuclear Regulatory Commission, International Atomic Energy Agency, Energy Information Administration, plant owner news releases, media reports, "Announced shutdowns" are reactors whose owners have announced specific shutdown dates. "Reactors identified at risk of closure" are from Deloitte, "Power and Utilities Accounting, Financial Reporting, and Tax Update," January 2016, p. 27, which listed reactors that had been identified as being at risk of retirement by at least one of the three major financial ratings agencies. Nine Mile Point 2, Perry, and Beaver Valley 1 and 2 are listed because of statements released by the plant owners.

Notes: Plants that have closed or are at risk because of "operating losses" may be affected by a combination of low regional power prices, high costs caused by relatively small size, rising capital expenditures, and other cost factors, as discussed in the text. NA=not applicable.

Recent Reactor Retirements

The first nuclear shutdown resulting from the recently changing competitive environment was the 566 megawatt single-unit Kewaunee plant in Wisconsin. In its October 2012 announcement that Kewaunee would be closed, plant owner Dominion said the small plant could not cover its costs in the midst of low regional power prices. An industry consultant commented after the announcement, "This might be the beginning of a new wave of shutdowns."[22] Kewaunee closed in May 2013.

Duke Energy decided on February 5, 2013, to retire the Crystal River 3 reactor in Florida. Crystal River's previous owner, Progress Energy, had severely damaged the reactor's massive concrete containment structure while attempting to replace the plant's steam generators. Duke Energy, which acquired Crystal River in 2012, said it decided to close the plant because of unacceptable uncertainty about the scope, cost, and duration of repairing or replacing the damaged containment structure.[23]

About two-thirds of U.S. nuclear power plants use steam generators to transfer heat from reactor cooling water to a secondary piping loop in which hot water is converted to steam to drive the turbine generators that produce electricity.[24] Most steam generators have required replacement after 20-30 years of service, a capital expenditure of several hundred million dollars per reactor.[25] Steam generators are such large components that temporary holes must be cut in the reactor containment to remove the old ones and bring in new ones.

Some nuclear plants have been closed and decommissioned to avoid the cost of steam generator replacement, such as Oregon's Trojan reactor in 1992. However, most nuclear plant owners have opted to replace the steam generators when necessary, and these projects, while requiring complex planning and execution, have become fairly routine in the nuclear power industry. No other steam generator replacement project caused containment damage similar to that suffered by Crystal River 3. Nevertheless, unrelated problems with another steam generator replacement project, at California's San Onofre station, also led to that plant's permanent shutdown just a month after Crystal River 3. Southern California Edison (SCE), the plant's owner, replaced the steam generators in units 2 and 3 in 2010 and 2011, respectively (unit 1 had been retired previously). One of the new steam generators experienced internal leakage about a year later; inspections showed vibration-related damage to all the new steam generators, later attributed by

[22] Hiruo, Elaine, "Kewaunee Closure Shows Impact of Natural Gas Prices: Analysts," *Nucleonics Week*, October 25, 2012.

[23] Carr, Hously, "Duke Decision to Retire Crystal River-3 Positive, Financial Analysts Say," *Nucleonics Week*, February 7, 2013.

[24] These are called "pressurized water reactors," or PWRs, because the reactor cooling water is kept under pressure to prevent boiling. The remaining third of U.S. commercial reactors are called "boiling water reactors," or BWRs, because their cooling water is allowed to boil, with the resulting steam flowing directly to the turbine generators. The BWR design eliminates the need for steam generators.

[25] For example, replacement of the two steam generators at the Waterford 3 reactor in Louisiana was estimated by the plant's owner at $550 million. See Entergy Corporation, "Entergy Louisiana Seeks Approval to Replace Waterford 3 Steam Generators," news release, June 27, 2008, http://www.entergy.com/News_Room/newsrelease.aspx?NR_ID=1203.

SCE to design flaws.[26] After considering options to repair or replace the damaged steam generators, SCE announced in June 2013 that it would retire San Onofre 2 and 3. The company cited uncertainty about whether and when the units would be allowed to restart at lower power by NRC, pending steam generator replacement or repair, as a major factor in the shutdown decision. Other considerations were the projected price of replacement power while repairs were being implemented and uncertainty about renewal of the two reactors' operating licenses in 2022, according to SCE.[27]

The Vermont Yankee plant was permanently closed in December 2014 because, according to plant owner Entergy, low power prices in New England were causing chronic losses. The single-reactor plant had received a 20-year license renewal from NRC in 2011, despite vigorous opposition from the state of Vermont that focused on leaks of radioactive tritium.[28] The license renewal allowed the plant to operate until 2032, but Entergy decided two years later to begin decommissioning the unit at the end of 2014. The company cited competition from shale gas-fired generation, the relatively high cost of operating a single-unit nuclear plant, and "artificially low energy and capacity prices in the region."[29]

Another single-unit nuclear plant, Fort Calhoun in Nebraska, was the most recent U.S. reactor to permanently close, on October 24, 2016. Fort Calhoun had been the smallest operating power reactor in the United States. Because it was owned by the Omaha Public Power District (OPPD), which sets its own rates, the nuclear plant had not been directly subject to the relatively low power prices in the region. However, OPPD determined that it could save up to $994 million for its customers over the next 20 years by closing Fort Calhoun and purchasing low-cost replacement power in the wholesale market. "The economic analysis clearly shows that continued operation of Fort Calhoun Nuclear Station is not financially sustainable," according to OPPD's chief executive.[30]

Announced Retirements and Potential Shutdowns

Ten operating reactors are currently facing permanent shutdown dates imposed by their owners or reached through negotiated agreements, as listed in the "announced shutdowns" section of **Table 2**.

FitzPatrick and Ginna

Facing the most imminent closure on this list are two single-unit New York plants, FitzPatrick, owned by Entergy, and Ginna, owned by Exelon. In announcing plans to close FitzPatrick, Entergy cited the relatively high operating costs of single-unit nuclear plants and "excess power supply and low demand" in the plant's upstate New York market. "Current and forecast power

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[26] Dolley, Steven, "SCE Aims to Hold Mitsubishi Accountable for San Onofre Generators," *Nucleonics Week*, July 25, 2013.

[27] Hiruo, Elaine, "Benefit of San Onofre Restart Dependent on No Delays: SCE Paper," *Nucleonics Week*, November 21, 2013.

[28] Beattie, Jeff, "Vermont Lawmakers Oppose Longer Life for Entergy Nuke," *IHS The Energy Daily*, February 25, 2010, http://www.theenergydaily.com/vermontlawmakers/.

[29] Hamilton, T.L., "Vermont Yankee Closure Seen Boosting New England Gas Demand," *Nucleonics Week*, August 29, 2013. For various viewpoints on the New England capacity market, see Turmelle, Luther, "Power Producers Gaming the System, David Cay Johnston Says," *New Haven Register*, February 27, 2015, http://www.nhregister.com/article/NH/20150227/NEWS/150229516.

[30] "Fort Calhoun Will Close October 24, OPPD Says," *Nucleonics Week*, September 1, 2016.

prices have fallen by about $10 per megawatt-hour, which equates to a projected annual loss of more than $60 million in revenues for FitzPatrick," said an Entergy statement.[31] Ginna faces a similar economic situation, according to Exelon. The company said the plant's total market-based revenues would be well below the $55-$60 per megawatt-hour required for profitability.[32]

In an effort to keep FitzPatrick and Ginna operating, along with Exelon's two-unit Nine Mile Point plant next to FitzPatrick, the State of New York Public Service Commission approved a system of Zero Emission Credits (ZECs) that would provide additional revenue for the four reactors. The ZEC program would require Exelon to purchase FitzPatrick from Entergy and operate all four of the upstate New York reactors through 2029.[33] Exelon has agreed to the purchase and to keep the four reactors running if the program is implemented as planned.

This ZEC funding is being provided in the wake of more than 10 years of experience with a market price on carbon in New York State through the Regional Greenhouse Gas Initiative (RGGI). Given the stated economics of the FitzPatrick and Ginna plants, this price advantage under the market price set through RGGI (approximately $5/ton of carbon dioxide or $2.70 per MWh) for low-carbon power units has not been sufficient to make these plants profitable.[34]

Clinton and Quad Cities

The next two shutdowns currently scheduled are Exelon's single-unit Clinton plant and the two-unit Quad Cities plant, both in Illinois. "Quad Cities and Clinton have lost a combined $800 million in the past seven years, despite being two of Exelon's best-performing plants," the company said in announcing the shutdowns.[35] The two plants must sell their power into wholesale electricity hubs at consistently lower prices than at adjacent hubs, a situation that has been attributed to chronic transmission congestion.[36] The Illinois General Assembly passed a bill (S.B. 2814) on December 1, 2016, that would provide ZECs to the Clinton and Quad Cities plants, along the lines of the New York ZEC program. Exelon had previously indicated that such assistance could keep the plants operating beyond their planned shutdown dates.[37]

Palisades

Entergy announced on December 8, 2016, that it would close its single-unit Palisades plant in Michigan on October 1, 2018. Palisades is in a competitive wholesale power market but earns nearly all its revenue under a PPA with Michigan utility Consumers Energy. The PPA, scheduled

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[31] Entergy, "Entergy to Close James A. FitzPatrick Nuclear Power Plant in Central New York," news release, February 23, 2016, http://www.entergynewsroom.com/latest-news/entergy-close-jamesfitzpatrick-nuclear-power-plant-central-new-york-1829/.

[32] Ostroff, Jim, "Outlook for Exelon's Ginna Uncertain after 2018, Analysts Say," *Nucleonics Week*, February 26, 2015.

[33] State of New York Public Service Commission, *Order Adopting a Clean Energy Standard*, Issued and Effective August 1, 2016, available at http://www3.dps.ny.gov/W/PSCWeb.nsf/96f0fec0b45a3c6485257688006a701a/56c58a580d2cf2e185257fd4006b90ce/$FILE/Order%20Adopting%20a%20Clean%20Energy%20Standard.pdf. See page 143.

[34] For more information, see CRS Report R41836, *The Regional Greenhouse Gas Initiative: Lessons Learned and Issues for Congress*, by (name redacted) .

[35] Exelon, "Exelon Announces Early Retirement of Clinton and Quad Cities Nuclear Plants," news release, June 2, 2016, http://www.exeloncorp.com/newsroom/clinton-and-quad-cities-retirement.

[36] Rorke, op. cit., p. 4.

[37] Freebairn, William, "Exelon Sees Chance of End-of-Year Action to Save Illinois Units: Official," *Nucleonics Week*, October 20, 2016.

to continue until 2022, was signed in 2007, when power prices were relatively high and expected to continue rising. In announcing the plant's retirement, Entergy said that, since 2007, "market conditions have changed substantially, and more economic alternatives are now available to provide reliable power to the region."[38] As a result, prices under the PPA, which started at $43.50 per MWh in 2007 and were to rise to $63 per MWh by 2022, have risen substantially above the market level.[39] Entergy's announcement said the early termination of the PPA would reduce electricity costs to Consumers Energy by $344 million from 2018 to 2022, and that the savings would be evenly divided between Entergy and Consumers Energy.

Pilgrim

Entergy plans to close its single-unit Pilgrim plant in Massachusetts in 2019. "The company is retiring the Pilgrim plant because of continued and projected low energy prices, with no expectation of market structure improvements, along with increased costs," according to Entergy's website.[40] A recent analysis by the R Street Institute said the plant's operation and maintenance costs had risen in recent years and that it needed significant capital expenditures to address safety-related equipment problems that had prompted heightened NRC scrutiny.[41] Although wholesale power prices in the New England market are high enough to cover Pilgrim's operation and maintenance costs, according to the analysis, revenue is not sufficient to justify the capital expenditures needed for the long term.[42]

Oyster Creek

Exelon's single-unit Oyster Creek plant in New Jersey, the nation's longest-operating power reactor, is also scheduled to be retired in 2019. When the plant's initial 40-year NRC license was renewed for 20 years in 2009, the State of New Jersey required it to comply with water discharge requirements by building closed-circulation cooling towers to reduce warm water discharges into Barnegat Bay. Exelon said the cooling towers would have cost $700-$800 million and that it would retire the plant if required to build them. Exelon and the New Jersey Department of Environmental Protection reached an agreement in 2010 to close Oyster Creek in 2019, a decade before its license expiration, without building the closed-circulation cooling system.[43]

Diablo Canyon

In contrast to the above closures, the planned shutdown of the two-unit Diablo Canyon nuclear power plant in California is not explicitly based on economic factors. Diablo Canyon is a rate-regulated plant, and therefore its owner, Pacific Gas and Electric (PG&E), is allowed to recover the plant's regulator-approved costs from ratepayers. PG&E contends that the plant "provides

[38] Entergy, "Palisades Power Purchase Agreement to End Early," news release, December 8, 2016, http://www.entergynewsroom.com/latest-news/palisades-power-purchase-agreement-end-early/.

[39] Beatie, Jeff, "Entergy Retiring Michigan Nuclear Plant Early Due to Financial Pressures," *IHS The Energy Daily*, December 9, 2016.

[40] Entergy, "Entergy Intends to Refuel Pilgrim in 2017; Cease Operations on May 31, 2019," news release, April 14, 2016, Frequently Asked Questions, http://www.pilgrimpower.com/operational-update/.

[41] Rorke, op. cit.

[42] Rorke, op. cit., p. 5.

[43] Dolley, Steven, "Exelon, New Jersey Agree To Shut Down Oyster Creek by 2019," *Nucleonics Week*, December 13, 2010.

low-cost, carbon-free energy" and is a "vital energy resource for California."[44] However, plant opponents have argued for decades that Diablo Canyon's location in a seismically active region poses unacceptable safety risks. The environmental group Friends of the Earth calls the plant "dangerous, destructive and expensive."[45] Friends of the Earth and other groups strongly opposed PG&E's 20-year license renewal applications to NRC, which would allow Diablo Canyon 1 and 2 to operate after 2024 and 2025, respectively. They also opposed the extension of a state land lease for the Diablo Canyon site that was to expire in 2018. To resolve the controversy, PG&E reached an agreement with a coalition of environmental and labor groups on June 21, 2016, to abandon the applications to NRC for Diablo Canyon license extensions in return for support from plant opponents for the state land lease extension (which was granted a week later). As a result, the Diablo Canyon reactors are now scheduled to operate until their current NRC licenses expire in 2024 and 2025. By that time, according to PG&E, sufficient alternative electricity generation will be available to meet regional market demand.

Other Potential Closures

Several nuclear power units have been identified by their owners as being at risk of permanent shutdown but without any specific dates or deadlines. An Exelon official was reported in March 2016 to have said the company's Nine Mile Point plant was "losing a lot of money," despite being a dual-unit plant with relatively large total generating capacity, and that the company might have to retire it in the future.[46] As mentioned above, Nine Mile Point may continue operating because of Zero Emission Credits being implemented by the state of New York. A FirstEnergy executive reportedly told financial analysts in November 2016 that his company would close or sell its merchant nuclear and coal plants within 18 months unless they could return to cost-based rate regulation or receive financial assistance. FirstEnergy's nuclear plants are the single-unit Perry and Davis-Besse plants in Ohio and the two-unit Beaver Valley plant in Pennsylvania. The analysts were reportedly told that the plants could not compete in regional wholesale power markets with low-cost electricity from natural gas plants and wind turbines.[47]

In addition to nuclear plants identified by their owners, several other reactors have been singled out by at least one of the major financial ratings agencies as being at risk of early retirement, generally because of market conditions. Byron 1 and 2 in Illinois were listed by UBS, and the single-unit Palisades plant in Michigan and Three Mile Island plant in Pennsylvania were listed by Fitch Ratings.[48]

[44] Pacific Gas and Electric Company, "Diablo Canyon," website, viewed November 10, 2016, https://www.pge.com/en_US/safety/how-the-system-works/diablo-canyon-power-plant/diablo-canyon-power-plant.page.

[45] Friends of the Earth, "Shutting Down Diablo Canyon," viewed November 10, 2016, http://www.foe.org/projects/climate-and-energy/nuclear-reactors.

[46] Knauss, Tim, "Nine Mile Point Nuclear Plant Faces Financial Peril, Exec Says," Syracuse.com, March 31, 2016, http://www.syracuse.com/news/index.ssf/2016/03/nine_mile_point_nuclear_plant_faces_financial_peril_exelon_exec_says.html.

[47] Funk, John, "FirstEnergy to Sell or Close Power Plants if Ohio, Pennsylvania Do Not Return to Regulated Rates," *Plain Dealer*, November 8, 2016, http://www.cleveland.com/business/index.ssf/2016/11/firstenergy_to_sell_or_close_p.html.

[48] Deloitte, *Power and Utilities Accounting, Financial Reporting, and Tax Update*, January 2016, p. 26, https://www2.deloitte.com/content/dam/Deloitte/us/Documents/energy-resources/us-er-power-utilities-accounting-financial-reporting-and-tax-update.pdf.

Merchant Nuclear Power Plant Economics

At the most basic level, existing nuclear power plants need to generate revenues from electricity sales, capacity markets (where available), and other potential sources that exceed the average total cost (ATC)—fuel, capital, and operating—of producing electricity in order to economically justify continuing operations. Generally, prices for wholesale electricity—the largest source of revenue for merchant nuclear power plants participating in competitive markets—have decreased in recent years while nuclear generation ATCs have increased. As a result, the financial condition of some U.S. nuclear power plants has been stressed and in some cases ATCs have exceeded revenues, resulting in actual and planned closures.

However, the degree of financial pressure across the nuclear fleet is not uniform. Each power plant is subject to a unique mix of market and cost variables, including (1) plant site and locational pricing, (2) the Regional Transmission Organization (RTO) market, (3) non-electricity revenue sources (e.g., capacity payments), (4) plant size, (5) transmission constraints, (6) generation mix within the transmission area, and (7) the marginal cost of electricity from price-setting fuels (e.g., coal and natural gas). A limited plant-level assessment of electricity revenues and fuel and operations and maintenance (O&M) costs is included in this report (see the **Appendix**). However, a detailed plant-by-plant financial analysis that includes all revenue and cost variables is beyond the scope of this report,[49] as are the economics and levelized cost of electricity (LCOE) considerations associated with constructing new nuclear plants.[50] The following sections provide an overview of concepts and trends that impact the financial and economic conditions considered by existing U.S. nuclear power plants.

Nuclear Power Generation Costs

Much of the discussion surrounding nuclear power economics has focused on revenue items such as low natural gas prices, the depressed wholesale market clearing prices that result, and low capacity revenues in some organized markets. These items certainly impact the economics of nuclear power, and this report includes discussion of these revenue-related issues. However, the cost portion of the financial equation is also important to understand due to its impact on economic viability.

At an industry-wide level, the Nuclear Energy Institute (NEI) reports that average total generating costs—which include fuel, capital, and operating costs—for nuclear electricity increased from $28.27 per megawatthour (MWh) to a peak of $39.70 per MWh in 2012 and in 2015 were reported to be $35.50 per MWh.[51] The NEI analysis indicates that while all cost categories have increased, capital expenditures were the largest contributor to average total costs, having more than doubled over the same time period.[52] NEI also reports that total average costs can vary depending on the number of reactor units at each power plant. Total average costs for multi-unit plants were $32.90 per MWh in 2015 versus $44.52 for single unit power plants. The majority of

[49] Bloomberg New Energy Finance (BNEF) published a report that evaluated the financial conditions of nuclear power plants that operate in competitive power markets. For more information, see BNEF, "Reactors in the Red: Financial Health of the US Nuclear Fleet," July 7, 2016.

[50] For background on LCOE calculations for nuclear and other electric power technologies, see Energy Information Administration, "Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2016," August 2016.

[51] Nuclear Energy Institute, *Nuclear Costs in Context*, April 2016.

[52] Ibid.

this difference is in the "operating" cost category.[53] In response to these cost trends, NEI has an active initiative called "Delivering the Nuclear Promise" which aims to reduce fleet-wide total generation costs by 30% by 2018 from the 2012 high of $39.70 per MWh.[54] For the purpose of comparing revenues and costs for the industry as a whole, average total costs of generation are used in order to illustrate the relationship between electricity sales revenue and all cash costs that are incurred.[55]

In addition to the NEI industry-wide average total cost information, CRS has access to 2015 plant-level fuel and O&M costs for 33 nuclear power plants that operate in competitive power markets.[56] This plant-level fuel and O&M cost information is compared with nodal electricity prices paid to each generator in order to determine whether revenue from electricity sales exceeds fuel and O&M costs (for additional information see the **Appendix**).[57]

How Are Competitive Wholesale Electricity Prices Determined?

In a competitive power market, the per-unit wholesale price of electricity (e.g., dollars per Megawatthour) paid to generators is their primary revenue source and is based on the economic concepts of supply and demand curves. Price determination in competitive markets is subject to Security Constrained Economic Dispatch[58] (SCED), which takes into account costs, transmission limitations, and reliability requirements.[59] In simple terms, all generators within a competitive market offer electricity at prices and volumes that are organized by the RTO from lowest to highest price in order to construct a supply curve (see **Figure 2**). Once expected demand levels and price bids for this time period (e.g., hourly) are determined, the price at which demand and supply intersect, when taking into account SCED considerations, is referred to as the "market clearing price." This is the price received by all generators that offered electricity at a price equal to or below the market clearing price level. As an example, a nuclear plant might offer to sell a certain volume of electricity at $7 per MWh (approximate value for fuel costs) and a wind generator may offer electricity for $0 per MWh.[60] However, if the clearing price is $40 per MWh (because the marginal generator submitted a $40 per MWh offer) then the nuclear plant and wind generator will be dispatched (i.e., ordered to run) and both will receive $40 per MWh for electricity provided during this time interval. **Figure 2** provides a hypothetical illustration of how wholesale electricity prices are generally determined.

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[53] Ibid.

[54] Nuclear Energy Institute, *Delivering the Nuclear Promise: Advancing Safety, Reliability and Economic Performance*, February 2016.

[55] Some economic analysts may argue that the decision to continue operating is based on revenues covering O&M and fuel costs only, since capital expenditures are amortized over multiple years. Average total generation costs are reflected in this report because capital expenses are cash expenditures that must be paid for through revenue/cash generation.

[56] Plant-level fuel and O&M costs from Rorke, op. cit.

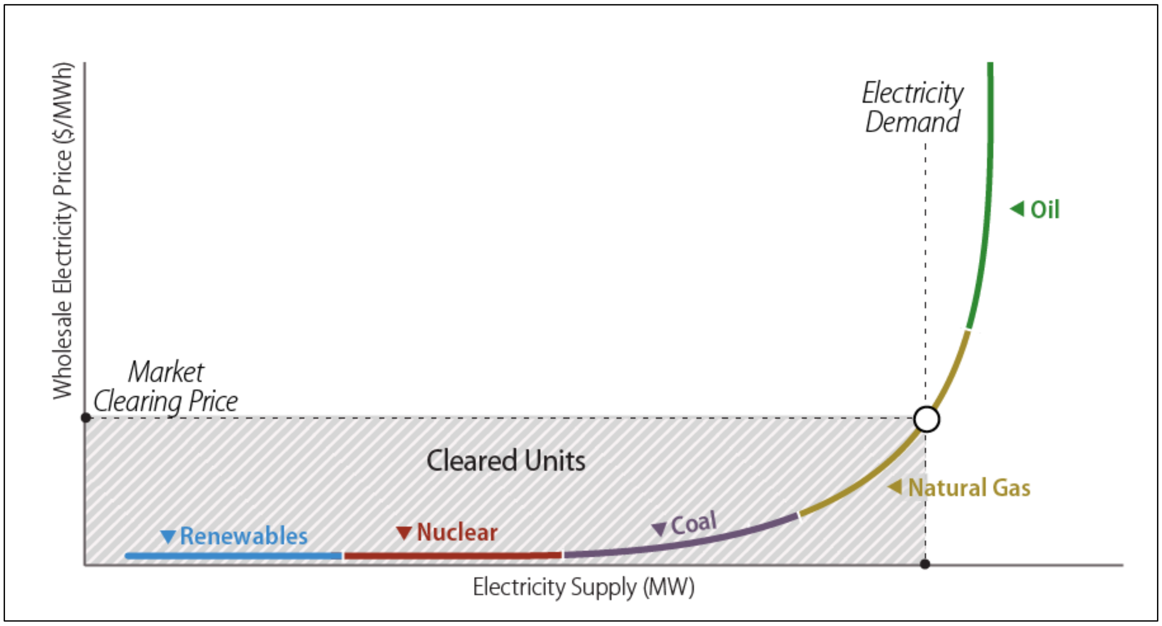
[57] Nodal electricity prices from Bloomberg New Energy Finance, *Reactors in the Red: Financial Health of the US Nuclear Fleet*, July 2016.

[58] The Energy Policy Act of 2005 (P.L. 109-58) defines the term "economic dispatch" to mean "the operation of generation facilities to produce energy at the lowest cost to reliably serve consumers, recognizing any operational limits of generation and transmission facilities."

[59] It is beyond the scope of this report to fully explain the concept of Security Constrained Economic Dispatch (SCED). For additional information about SCED, see Federal Energy Regulatory Commission, *Security Constrained Economic Dispatch: Definition, Practices, Issues and Recommendations*, July 31, 2006.

[60] See text box below, *Wind Power and Negative Electricity Prices: What Is the Relationship?*, for a discussion of how these offers may be zero or even negative.

Figure 2. Illustrative Example of Wholesale Electricity Price Formation in a Competitive Power Market



Source: CRS

Notes: Not representative of actual RTO/ISO market clearing results. Actual values for electricity prices and electricity supply are not indicated in this figure, as they will vary by market, generation mix, time-of-day, and location.

Nuclear power being offered at less than the market clearing price does not necessarily mean that it is profitable. Merchant nuclear plants are generally viewed as "price takers" in a wholesale power market since the plants generally prefer to operate on a continuous basis, regardless of the market price. However, indications are that some nuclear generators may start following demand load patterns in order to improve electricity sales revenues in some locations.[61] Typically, merchant nuclear plants want to offer prices low enough to clear the market and will participate in the competitive power markets in a way that ensures market clearance and dispatch. As a result, nuclear plant profitability is generally a function of the market clearing price level that is set by price-setting units.

In practice, price formation in wholesale power markets can be quite complex, with the RTO/ISO having to manage various system constraints (e.g., transmission, scarcity, reliability) that can challenge the simple application of supply and demand curves.[62] Nevertheless, supply and demand fundamentals are the underlying premise by which wholesale electricity prices are determined.

Generally, price offers are a function of the fuel cost needed to generate a unit of electricity, and do not include capital costs. The fuel cost for wind is zero and, according to the Nuclear Energy Institute, the fuel cost for nuclear was approximately $7 per MWh in 2015.[63] Also, nuclear

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[61] *Nuclear Intelligence Weekly*, "Utilities: Exelon Moves Reactors Toward Load-Following," September 16, 2016.

[62] The Federal Energy Regulatory Commission (FERC) evaluates various issues associated with price formation in RTO/ISO power markets. A compilation of FERC's energy price formation work is available at http://www.ferc.gov/industries/electric/indus-act/rto/energy-price-formation.asp.

[63] Nuclear Energy Institute, *Nuclear Costs in Context*, April 2016.

generators—because plants generally prefer to operate on a consistent and near-continuous basis—will offer power at low prices. Wind generators—because many projects receive out-of-market revenue/value sources (e.g., power purchase agreements, tax credits, renewable energy credits)—also want to clear the market and may be motivated to submit zero or even negative price offers, if allowed by the respective RTO, to ensure that they clear and are dispatched (for more information see text box below titled *Wind Power and Negative Electricity Prices: What Is the Relationship?*). Coal and natural gas generators, on the other hand, will typically offer electricity prices that are a function of fuel acquisition costs, which can vary based on benchmark fuel prices, the location at which the generator purchases the fuel, and the conversion efficiency (heat rate) of the power plant.[64]

How Natural Gas and Coal Impact Wholesale Electricity Prices

Natural gas and coal play an important price-setting role in competitive power markets. For the purpose of this discussion, focus is placed on the role of natural gas and how the price of this fuel can affect the wholesale price of electricity paid to generators. Natural gas affects wholesale electricity prices in two primary ways. First, because natural gas power generators are generally able to follow demand/load patterns and can be dispatched with relative ease, they often set prices during peak demand hours—when electricity demand and prices are typically the highest each day. Second, natural gas power generation is a primary price-setting fuel for wholesale electricity prices in competitive power markets. **Table 3** indicates the percentage of time intervals that various fuels set the real-time price in three different RTOs during different years.

Table 3. Price-Setting Fuel Type Used by Real-time Marginal Generating Units

	MISO		ERCOT		PJM	
	2007	2015	2007	2015	2011	2015
Natural Gas	27.5%	76.0%	92%	50%	25.8%	35.5%
Coal	67.8%	22.7%	8%	45%	68.7%	51.7%
Other	4.7%	1.3%	0%	5%	5.5%	12.8%

Source: Potomac Economics provided, via email, price setting information for MISO and ERCOT at the request of CRS. PJM price setting information from Monitoring Analytics, *State of the Market Report for PJM*, 2011 and 2015.

Notes: Potomac Economics is the Market Monitor for MISO and ERCOT. Monitoring Analytics is the PJM Market Monitor. MISO and ERCOT price setting information was made available for 2007 and 2015. These years were selected to be consistent with other figures contained in this report. PJM price setting information reflects 2011 and 2015. CRS was not able to locate the same price-setting information for 2007. The integration of MISO South by MISO in 2013 contributed to an increase in natural gas power generation and price setting.
MISO = Midwest Independent System Operator. ERCOT = Electric Reliability Council of Texas. PJM was an acronym for Pennsylvania, Jersey, Maryland; however, today it is not an acronym and is simply a brand name for the system operator.

Data contained in **Table 3** suggest that natural gas is a primary price-setting fuel within the three RTOs included in the table. The price-setting contribution of natural gas in MISO and PJM has

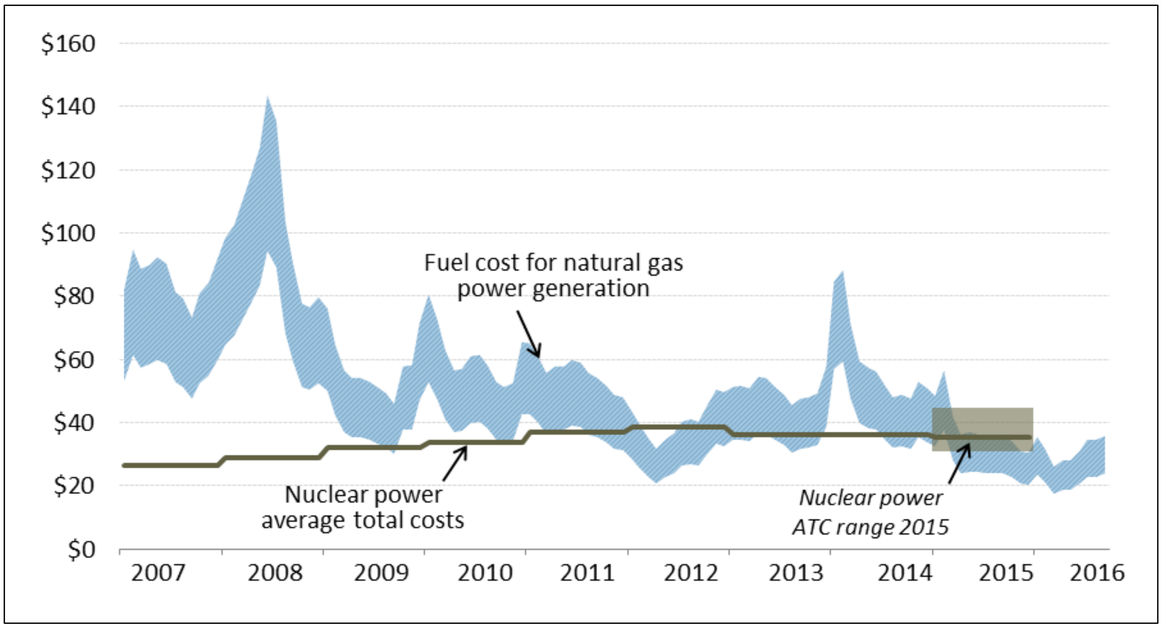
[64] Heat rates for combustion technologies such as a steam, gas turbine, internal combustion, and combined cycle unit indicate the amount of energy—measured in British thermal units or BTUs—needed by each respective technology to produce one kilowatthour of electricity. The Energy Information Administration (EIA) publishes average heat rates in the *Electric Power Annual* publication. See http://www.eia.gov/electricity/annual/html/epa_08_02.html.

increased over the respective periods included in the table. While the ERCOT price-setting information suggests that natural gas may have declined in terms of its price-setting role within that RTO, the Market Monitor report indicates that the 34% real-time energy price decline observed in this market from 2014 to 2015 was "primarily driven by lower natural gas prices."[65]

Commodity fuel prices for natural gas and coal generally have the largest impact on wholesale electricity prices. With natural gas increasing its price-setting role in some competitive markets, a general analysis of fuel costs for natural gas-derived electricity provides an indication about the downward pressure natural gas has exerted on wholesale electricity prices, and therefore revenue for electric power generators. See **Figure 3**.

Figure 3. Fuel Costs for Natural Gas Power Generation and Average Total Costs for Nuclear Power Generation

Dollars per Megawatthour (MWh) of Electricity (Nominal)



Source: Natural gas power generation marginal cost range: CRS, using heat rate and monthly natural gas for electric power price information from Energy Information Administration, Natural Gas Prices, available at http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm, accessed December 2016 with data through September 2016. Nuclear power average total costs and range: Nuclear Energy Institute, *Nuclear Costs in Context*, April 2016.

Notes: Nuclear power average total costs include fuel, O&M, and capital.

The fuel cost range for generating electricity from natural gas has declined since peaking in 2008, while the ATC (fuel, operations and maintenance, and capital) for nuclear power generation has increased, relative to 2008 levels.[66] As discussed above, lower natural gas costs generally translate into lower wholesale power prices. The combination of rising nuclear generation costs and declining natural gas prices is contributing to the financial challenges encountered by nuclear power plants in competitive power markets. Natural gas fuel costs per MWh ranges in **Figure 3**

[65] Potomac Economics, *2015 State of the Market Report for the ERCOT Wholesale Electricity Markets*, June 2016.

[66] Fleet-wide Average Total Costs are used to compare against general gas price and electric power market trends in this report. However, plant-level analysis included in this report compares electricity prices/revenues with fuel and O&M costs only.

reflect U.S.-wide averages, and it should be noted that each individual nuclear plant will be subject to a unique set of market and location-based price variables that can impact revenue from electricity sales.

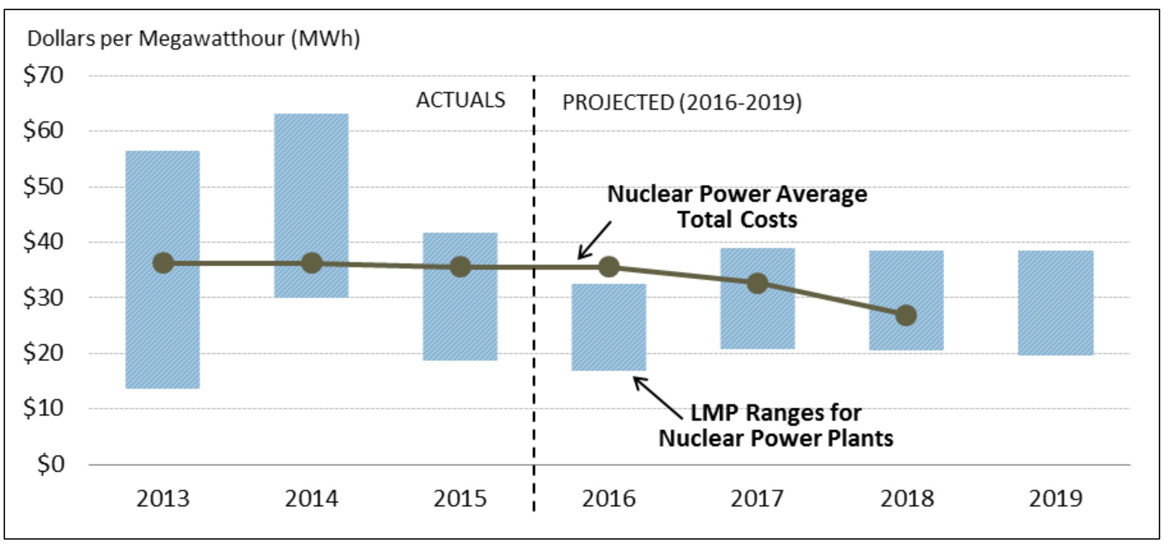
Locational Marginal Prices

In competitive power markets, there is not a single wholesale electricity price paid to all electricity generators operating in an RTO region. Rather, electricity revenues received by generators are a function of locational marginal prices (LMPs), which vary within each RTO. LMPs generally include three primary price components: (1) energy, (2) transmission congestion, and (3) energy losses.[67] LMPs can be affected by market variables such as fuel prices, generation mix, and transmission constraints at a specific location. In some locations, the presence of renewable electricity generation from wind and solar projects can affect LMPs and in some instances can cause real-time LMPs to drop below zero for limited periods of time. (See text box below: *Wind Power and Negative Electricity Prices: What Is the Relationship?*)

As discussed above, the cost of fuel (i.e., natural gas and coal) affects clearing prices, and fuel costs can also vary by location. For example, due to potential transportation cost and infrastructure limitations, the price of natural gas paid by a power generator in Pennsylvania might be different from that paid by a generator in New York. All else being equal, the electricity market clearing price at these respective locations might also be different. **Figure 4** shows the range of LMPs for nuclear power plants operating in competitive power markets along with average total costs for nuclear power generation.

Figure 4. Competitive Power Market LMPs for U.S. Nuclear Power Plants

LMP Ranges and Nuclear Power Average Total Costs (Nominal)



Source: CRS. LMP ranges from Bloomberg New Energy Finance, *Reactors in the Red: Financial Health of the US Nuclear Fleet*, July 2016. Nuclear average total costs from Nuclear Energy Institute, *Nuclear Costs in Context*, April 2016.

[67] Federal Energy Regulatory Commission, *Energy Primer: A Handbook of Energy Market Basics*, November 2015.

Notes: LMPs for each nuclear plant were obtained from the Bloomberg terminal, which also includes forward price projections through 2019. Nuclear power average total costs through 2015 are from NEI, with 2016 to 2018 projections calculated based on NEI's "Delivering the Nuclear Promise" stated goals.

LMP and ATC projected estimates for calendar year 2016 indicate that the entire expected electricity price range for nuclear power plants in competitive markets may be less than the ATC of nuclear electricity generation. While this projection does not include other revenue sources and does not suggest that all nuclear power plants will realize revenue that is less than cost, it does indicate that the location and cost structure of each nuclear power facility is an important consideration when assessing the financial challenges of a specific plant.

Wind Power and Negative Electricity Prices: What Is the Relationship?

The presence of wind electricity generation in certain locations has been an item of concern for some nuclear power operators due to its effect on locational marginal prices (LMPs) and, therefore, the nodal electricity price that is paid for nuclear generation. Under certain conditions and in some specific locations, real-time LMPs can drop below zero for limited periods of time. These temporary negative prices generally result from power generation being in excess of demand during a particular time interval (e.g., an hour late at night when wind generation is high and power demand is low). Since there is limited electricity storage capacity in the electric power system, the transmission operator must constantly balance supply and demand in order to maintain the operational integrity of the system. Negative prices generally reflect transmission congestion at a location and are a signal to incentivize generators to lower production in order to balance supply and demand at a specific location. In certain areas, northern Illinois for example, there can be large amounts of wind power and nuclear generation serving the same demand node through a common transmission system. During low demand hours (i.e., late night and early morning), there can be times when electricity supply might exceed demand, and price signals are used to alter generator behavior and bring the system back into balance.

The role of wind power and the occurrence of negative wholesale power prices are related to federal tax incentives that are available to wind power generators. According to the American Wind Energy Association (AWEA), wind power projects that are still in the 10-year production tax credit (PTC) eligibility window will typically offer electricity between -$20 and -$35 per Megawatthour.[68] This price offer essentially means that these units are willing to continue producing electricity until the applicable LMP drops below the offer price.

In practice, it is not common for generators to pay money in order to generate electricity—which is what negative prices imply. Reported negative prices generally occur in the real-time market, which makes up only 5% of electricity transactions. Additionally, negative prices in real-time markets are infrequent. Nevertheless, real-time prices and day-ahead prices (95% of electricity transactions) typically converge over time. As a result, periods of negative real-time LMPs can have a price depression effect on day-ahead wholesale prices that are paid to generators and therefore impact generator revenue.

A quantitative example of how wind power and transmission congestion affect pricing is the Quad Cities nuclear power plant in Illinois. In 2015 the Northern Illinois Hub power price—the hub or regional price relevant to Quad Cities—was $27.93 per MWh.[69] However, the nodal electricity price—which reflects the actual price paid for electricity—for Quad Cities was $19.60 per MWh in 2015.[70] This price difference indicates how the presence of wind generation and its contribution to transmission congestion can have a noticeable impact on electricity sales revenue. Exelon, the owner and operator of Quad Cities, has indicated its intention to start operating its nuclear fleet in a way that follows electricity demand—load following. This could potentially reduce transmission congestion in certain areas and result in nodal prices becoming more normalized with regional hub prices.

Other Revenue Sources

In addition to electricity sales, which are the largest revenue source for nuclear power plants, some RTO/ISO markets provide other revenue opportunities for power generators. Capacity,

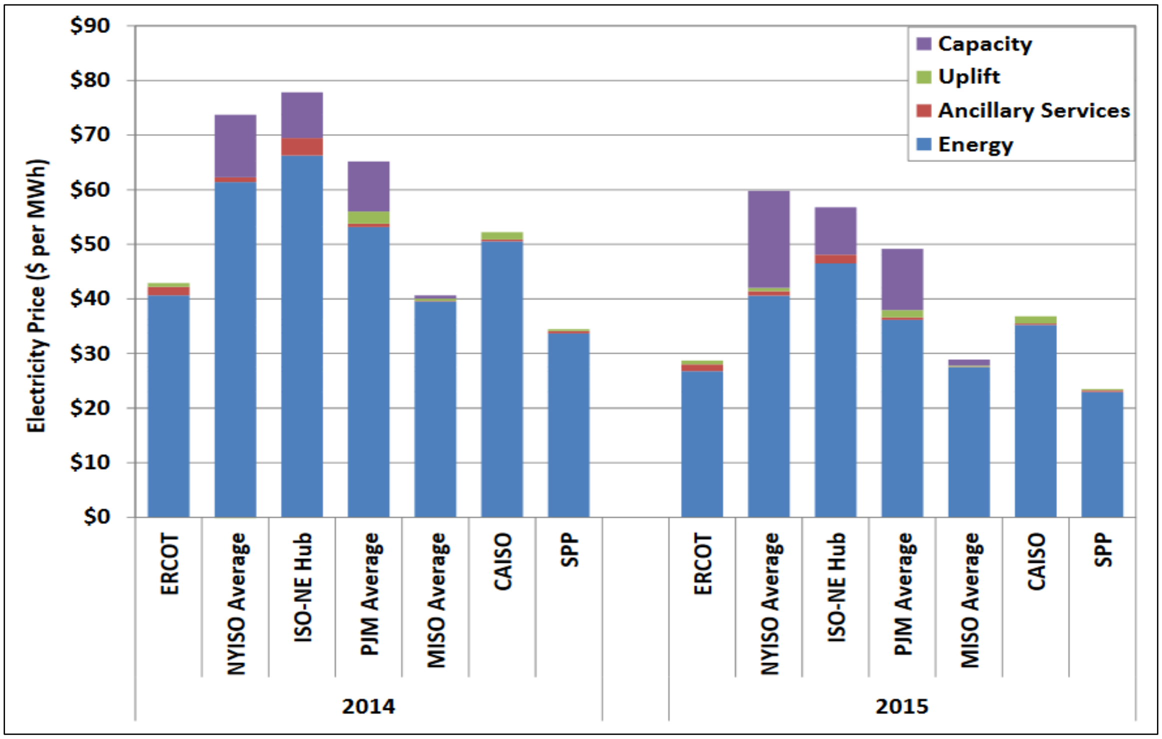
[68] American Wind Energy Association, "Negative Prices Still Rare, Mostly Caused by Other Energy Sources," April 15, 2016, available at http://www.aweablog.org/negative-prices-still-rare-mostly-caused-by-other-energy-sources/.

[69] R Street Institute, *Where Have All the Nuclear Plants Gone?*, October 2016.

[70] Bloomberg New Energy Finance, *Reactors in the Red: Financial Health of the US Nuclear Fleet*, July 2016.

uplift, and ancillary services—all defined in the following text—are some areas where generators can be compensated for providing certain services other than selling electricity. **Figure 5** provides average all-in electricity prices for various RTO/ISO markets by revenue source.

Figure 5. Comparison of All-in Prices in Different Markets



Source: Potomac Economics, *ERCOT 2015 State of the Market Report*, June 2016.

Notes: Numbers in this figure represent RTO/ISO averages and may not reflect the actual value received by a specific power generator. Uplift payments are essentially compensation paid to some generators in the event that revenue received from the wholesale power market is less than marginal operating costs. While these payments do not guarantee dispatch, a price for electricity generated, or a threshold rate of return, uplift payments, in essence, do provide some degree of assurance that generators might not operate at a loss. Ancillary services include services such as frequency regulation and voltage control that are used to help balance the transmission system.

ERCOT = Electric Reliability Council of Texas. NYISO = New York Independent System Operator. ISO-NE = Independent System Operator-New England. MISO = Midwest Independent System Operator. CAISO = California Independent System Operator. SPP = Southwest Power Pool.

The largest source of non-energy revenue in some competitive power markets is in the form of capacity payments. To ensure resource adequacy, most RTO/ISOs have developed and evolved capacity markets that provide an economic signal that would provide incentives for adequate generation for peak power demands and to ensure that generation resources are available to satisfy future demand.[71] Depending on the RTO, capacity payments can be made through either a bilateral contract between a load serving entity (LSE) and a generator or through participation in a capacity auction that is organized and administered by the RTO/ISO. However, not all RTO/ISOs have a capacity market (e.g., ERCOT does not have a capacity market and uses

[71] For additional capacity market background, see Federal Energy Regulatory Commission, *Centralized Capacity Market Design Elements*, August 23, 2013.

scarcity pricing[72] as an incentive for motivating new generation sources). For those that do, each has a unique market design that determines the value of and time frame for capacity payments. As indicated in **Figure 5**, capacity payments can vary by RTO, and some RTOs have changed their capacity market designs in such a way that may benefit nuclear power generators.[73] Additionally, power plant location can impact the value of capacity payments received by nuclear and other power generators. For example, PJM's 2019/2020 Reliability Pricing Model (RPM) capacity market resulted in clearing prices that ranged from $100 per MW-day to $202 per MW-day across different zones.[74] RPM and similar forward capacity markets guarantee payments for new capacity that performs as projected. Nuclear power plants are eligible for capacity payments, although not all merchant nuclear generators clear capacity auctions.

Power Purchase Agreements (PPAs)

Some nuclear power plants that operate in competitive power markets have separate power purchase agreements (PPAs) outside the RTO market that provide a specified value for electricity generation. The existence of a PPA reduces the price risk to nuclear power producers associated with participating in competitive power markets. It is not clear how many nuclear plants in competitive power markets have PPAs. However, an industry source suggests that at least six nuclear plants have PPAs for either all or a portion of their generating capacity.[75] Depending on the contractual terms—not made available to CRS—included in each agreement, these PPAs could potentially provide some financial stability to plants with such agreements.

Case Study: Quad Cities Nuclear Generating Station

Located in Cordova, IL, the Quad Cities Nuclear Generating Station consists of two nuclear reactors with a combined net summer electric capacity of approximately 1,820 Megawatts. The plant is partially rate regulated, with 25% of the plant under Iowa rate regulation and the other 75% participating in the PJM power market. On June 2, 2016, Quad Cities owner-and-operator Exelon announced that it was moving forward to shut down and retire the plant before the end of its operating license.[76] Available price information, capacity payments, and production costs (fuel, operations and maintenance) make it apparent that the Quad Cities power plant is under a degree of financial stress.

[72] ERCOT uses a Scarcity Pricing Mechanism (SPM) to provide economic signals that would motivate development and construction of new generation assets that would satisfy demand expectations. The SPM essentially sets caps for price offers from generators. As of June 2015, the ERCOT system-wide offer cap was $9,000 per MWh. The SPM also has cost containment mechanisms as part of its design that are based on net margins for "peaker" plants that provide incremental generation during peak demand times.

[73] PJM, for example, is in the process of transforming its Reliability Pricing Model auction to deliver a Capacity Performance product, which could result in higher capacity payments to some generators, including nuclear. For more information, see http://www.pjm.com/~/media/documents/reports/20150720-capacity-performance-at-a-glance.ashx, accessed October 26, 2016.

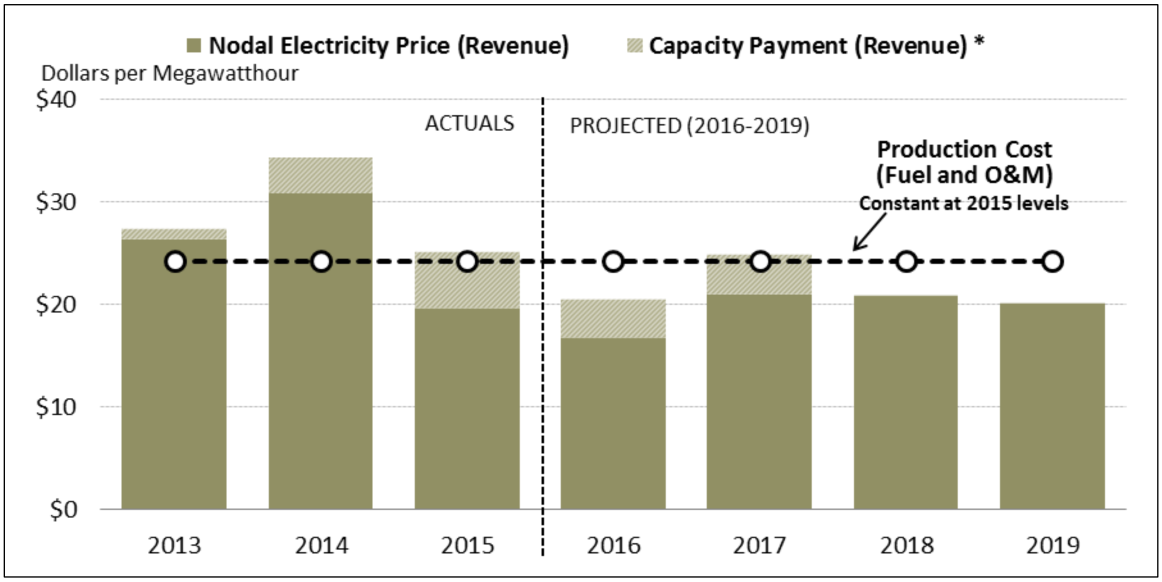
[74] PJM, 2019/2020 RPM Base Residual Auction Results, available at http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2019-2020-base-residual-auction-report.ashx, accessed October 17, 2016.

[75] Identified in a confidential spreadsheet provided to CRS from an industry source, power plants that have some or all of their capacity subject to a PPA are (1) Cooper (3%), (2) Duane Arnold (70%), (3) Palisades (100%), (4) Point Beach (100%), (5) Ginna (100%), and (6) Seabrook (4%). The Ginna plant in New York is under a Reliability Support Services Agreement (RSSA), which supports continued operations of power generators that want to retire but are needed to ensure system reliability.

[76] Exelon, "Exelon Announces Early Retirement of Clinton and Quad Cities Nuclear Plants," news release, June 2, 2016, http://www.exeloncorp.com/newsroom/clinton-and-quad-cities-retirement.

Figure 6. Quad Cities Revenue and Cost Information

Dollars per Megawatthour (MWh) of Electricity (Nominal)



Source: Nodal Electricity Price: Bloomberg as reported in Bloomberg New Energy Finance, *Reactors in the Red: Financial Health of US Nukes*, July 2016. Capacity Payment: CRS analysis of PJM capacity prices for the COMED zone as reported by Monitoring Analytics, LLC, *Quarterly State of the Market Report for PJM: January through June*, 2016. Production cost information for 2015 as reported in *Nucleonics Week*, "US Utility Operating Costs," June 2, 2016.

Notes: Production cost estimates for 2013-2019 are assumed to be at 2015 levels. Cost estimates do not include any capital expenditures. Such expenditures for the Quad Cities plant were not available to CRS. Capacity values were calculated by starting with PJM COMED capacity prices as reported by the market monitor. It is assumed that the Quad Cities plant cleared the capacity market for the years 2013 to 2017. Exelon officially announced that Quad Cities did not clear the capacity market for the years 2018 and 2019. Since 25% of Quad Cities is rate regulated and the power is provided to Iowa, the total Quad Cities net summer capacity and electricity production was reduced by 25% for the purpose of calculating the $/MWh capacity payment values included in this figure.

* Capacity auctions in PJM are for years that start on June 1 and end on May 31. Quad Cities did not clear the 2018/2019 or 2019/2020 capacity auctions. The table does not include capacity revenues for 2018, but Quad Cities is to receive capacity payments through May 31, 2018, as a result of clearing the 2017/2018 capacity auction.

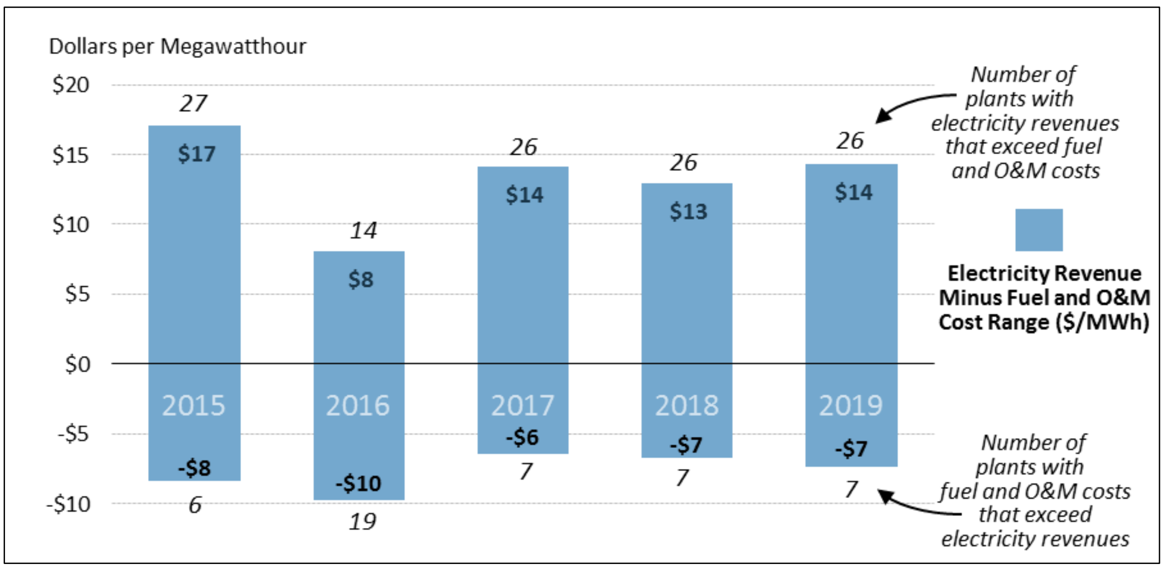
Generally, the nodal electricity price that determines the value of electricity sold by the Quad Cities power plant has been volatile in the years 2013 to 2016 and is expected to be below fuel and O&M costs in 2016. PJM capacity payments for Quad Cities provide some additional revenue. However, the combination of capacity payments and electricity sales is estimated—assuming constant production costs at 2015 levels—to be less than production costs in 2016, not considering any capital expenditures. Current electricity price projections and capacity auction results indicate that electricity sales will not be large enough to pay for production costs, although capacity payments in 2017 may provide supplemental revenue that cover production costs. The Quad Cities plant did not clear the 2018/2019 or 2019/2020 capacity auctions; therefore the plant is not eligible to receive capacity payments during those years. Faced with low electricity price projections and revenues that are expected to be less than fuel and O&M costs, not to mention any capital expenditures, Exelon management decided that it is in the financial best interest of the company to shut down the power plant. The Illinois legislature passed S.B. 2814 on December 1, 2016, which includes a Zero Emissions Credit (ZEC) incentive program for existing nuclear plants in the state. This may result in continued operations of the Quad Cities nuclear plant.

Plant-Level Analysis of Electricity Sales Revenue and Fuel and O&M Costs

Plant-specific cost and price information available to CRS for 33 nuclear power plants that operate in competitive power markets was used to assess whether electricity revenue did, or is expected to, exceed 2015 fuel and O&M costs for each plant for the years 2015 to 2019.[77] The analysis is unique, compared to materials reviewed for this report, in that it compares plant-level nodal electricity prices with plant-level fuel and O&M costs. Nevertheless, this analysis is inherently limited and is included in this report as an initial financial condition assessment of merchant nuclear power plants. Additional revenue sources (e.g., capacity payments) and other costs (e.g., capital) at the plant level were not available to CRS and were not included in the estimates presented. As a result, CRS is not making an assessment of which reactors are at risk of closure. The estimates provide an incomplete view of nuclear power economic viability. **Figure 7** summarizes the results of this analysis. **Table A-1** in the **Appendix** provides plant-specific estimates for each of the 33 plants on a per MWh basis.

Figure 7. Analysis of Electricity Sales and Fuel and O&M Costs for 33 Nuclear Power Plants

2015-2019



Source: CRS using data from third-party reports. Bloomberg New Energy Finance, *Reactors in the Red: Financial Health of the US Nuclear Fleet*, July 11, 2016. R Street Institute, *Where Have All the Nuclear Plants Gone?*," October 2016.

Notes: Nodal prices at each power plant location were used for plant-level revenue. Fuel and O&M costs, as presented in the R Street report, were used for cost estimates. Fuel and O&M costs were held constant at 2015 levels. Additional assumptions regarding the calculations made for this chart are included in the **Appendix**.

Generally, from the perspective of electricity revenues versus fuel and O&M costs, calendar year 2016 is projected to have been quite challenging for many existing nuclear power plants. Based on data sources available to CRS, and assuming that all electricity is sold in the wholesale market,

[77] Plant-level fuel and O&M costs from Rorke, op. cit. Nodal electricity prices from *Bloomberg New Energy Finance, Reactors in the Red: Financial Health of the US Nuclear Fleet*, July 2016.

19 of the 33 power plants are estimated to have fuel and O&M costs that exceed electricity sales revenue in 2016. Due to forward electricity prices being projected to increase in the near term, this number is projected to drop to seven for the years 2017 to 2019. While this analysis is limited by available plant-level data for all revenues and costs, it does indicate that some nuclear power plants are encountering financial challenges that may be difficult to manage in the near term.

Policy Options and Considerations

The increasing number of recent nuclear power plant closures and announced early retirements has motivated discussion about whether the federal government should provide financial support mechanisms for existing nuclear power facilities.

The nuclear industry and its supporters contend that such support is in the national interest because nuclear power plants provide large amounts of highly reliable,[78] low-carbon electricity.[79] However, opponents contend that nuclear power suffers from too many drawbacks (such as accident risk and waste management problems) and that federal incentives should focus instead on renewable energy and efficiency. Furthermore, federal financial incentives for existing nuclear power would likely be opposed by owners of other generating assets that could potentially benefit financially as a result of early nuclear plant retirements. Nevertheless, if federal support for nuclear power were pursued, Congress would have a variety of options to consider, each with its own set of policy questions.

One challenge associated with federal-level nuclear incentives is that financial conditions across the entire fleet are not uniform. Each nuclear power facility is subject to a unique set of cost, price, and financial performance variables. To date, much of the policy action has taken place at the state level, with several states considering, passing, or implementing legislation/regulations to support nuclear power (see text box below, *State-Level Policy Action to Support Existing Nuclear Power Plants*).

Secretary of Energy Ernest Moniz has reportedly indicated that the federal government has limited existing authority to provide financial support for operating nuclear power plants and that doing so is currently a state issue.[80] A recent report by the Secretary of Energy Advisory Board Task Force on the Future of Nuclear Power included this recommendation for the Department of Energy (DOE):

[78] Nuclear plants consistently have a high capacity factor, averaging close to 90% for the years 2013 to 2015. Capacity factor indicates what percentage of the 8,760 hours in each year a power generating facility is operating at full capacity. For a comparison of capacity factors for different power generating technologies in the United States, see Energy Information Administration, *Electric Power Monthly*, Table 6.7.B. Capacity Factors for Utility Scale Generators Not Primarily Using Fossil Fuels, January 2013-September 2016, November 29, 2016.

[79] Nuclear power plants are often referred to as having "zero emissions" of greenhouse gases, such as carbon dioxide, because they do not directly combust fossil fuels to generate electricity. However, energy from fossil fuels is generally used during the mining and processing of uranium to produce nuclear reactor fuel, and greenhouse gases are emitted during the production of concrete and other materials for plant construction and during plant decommissioning. The International Atomic Energy Agency (IAEA) estimates that such "life cycle" greenhouse gas emissions from nuclear power generation are similar to the life-cycle emissions from wind, solar, and hydropower, which also are typically classified as "zero emission" electricity sources. See IAEA, *Climate Change and Nuclear Power 2016*, p. 19, http://www-pub.iaea.org/MTCD/Publications/PDF/CCANP16web-86692468.pdf. Other studies have found life-cycle nuclear emissions of greenhouse gases to be higher than renewable sources but still a fraction of emissions from natural gas, the lowest-emitting fossil fuel generation source. See Kleiner, Kurt, "Nuclear Energy: Assessing the Emissions," *Nature Reports Climate Change*, September 24, 2008, http://www.nature.com/climate/2008/0810/full/climate.2008.99.html.

[80] Environment and Energy Daily, *Nuclear: Plant Closures Are 'A State Issue'—Moniz*, September 15, 2016.

> For existing nuclear plants, the Task Force endorses DOE's efforts to work with the Federal Energy Regulatory Commission (FERC), State regulatory authorities, and regional and independent system operators to encourage arrangements that will preserve the U.S. fleet until the end of their useful life, subject to continued compliance with prevailing safety and environmental regulations. The Task Force believes this is essential if U.S. carbon goals are to be achieved.[81]

A range of policy options are available to Congress, should it choose to act, that could potentially provide some degree of financial support for operating U.S. nuclear power plants.[82] Some of these potential options are discussed in the following sections.

Power Market Price Formation Changes

In March 2015 the Nuclear Energy Institute (NEI), along with other industry groups, announced a joint effort to pursue market and price reforms in competitive electric power markets. The groups sent a letter to the Federal Energy Regulatory Commission outlining a set of principles for price formation reforms.[83] Generally, the primary market reform argument is that clearing prices do not include all costs (e.g., start-up and uplift) associated with operating an electric power system. As a result, LMPs may be lower than they otherwise would be if all costs were included. FERC has an ongoing Energy Price Formation initiative to evaluate electricity price formation in RTO and ISO markets.[84] In June 2016 FERC issued a rule requiring RTOs/ISOs to change their settlement procedures and shortage pricing triggers in order to more accurately compensate generation resources.[85] FERC is also evaluating other price formation issues (e.g., uplift payments); future rules could potentially impact electricity price formation in wholesale markets. Congressional action in this area could include oversight of how FERC's Energy Price Formation initiative might impact nuclear power generators. This effort is consistent with the Future of Nuclear Power task force recommendation referenced above.

Tax Incentives

A federal production tax credit (PTC) is currently available for the generation of electricity by new, advanced nuclear power facilities during their first eight years of operation.[86] However, no federal tax incentives are available for existing nuclear power plants. Generally, currently available energy tax credit incentives are designed to encourage construction and operation of new energy production facilities and are based on either energy/electricity production (i.e.,

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[81] U.S. Department of Energy, *Secretary of Energy Advisory Board Report of the Task Force on the Future of Nuclear Power*, September 22, 2016, http://www.energy.gov/seab/downloads/final-report-task-force-future-nuclear-power.

[82] The American Nuclear Society published a report that outlines several policy options at the federal and state level that would support nuclear power generation. For more information, see American Nuclear Society, *Nuclear in the States Toolkit: Policy Options for States Considering the Role of Nuclear Power in Their Energy Mix,* June 2016.

[83] Edison Electric Institute, Electric Power Supply Association, Natural Gas Supply Association, Nuclear Energy Institute, and America's Natural Gas Alliance, Letter to FERC Chairman and Commissioners, March 6, 2015, available at http://www.nei.org/CorporateSite/media/filefolder/Policy/Market/Joint-Trade-Assns-Letter-to-FERC-on-Price-Formation-Principles.pdf?ext=.pdf.

[84] Federal Energy Regulatory Commission, https://www.ferc.gov/industries/electric/indus-act/rto/energy-price-formation.asp, accessed November 2, 2016.

[85] Federal Energy Regulatory Commission, 155 FERC 61,276: *Settlement Intervals and Shortage Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators*, June 16, 2016.

[86] Internal Revenue Code (IRC) Section 45J includes a non-inflation adjusted production tax credit of 1.8 cents per kilowatthour for qualifying advanced nuclear power facilities.

production tax credit or PTC) or investment (i.e., investment tax credit or ITC). In addition to the nuclear PTC for new plants mentioned above, two specific energy tax credits currently available to renewable energy technologies are (1) the Renewable Electricity Production Tax Credit,[87] and (2) the Investment Tax Credit for renewable energy.[88] Legislation making existing nuclear power generation eligible for either of these existing tax credit incentives would provide some financial value and could potentially support continued operation of at-risk plants. However, since the financial condition across the entire U.S. nuclear fleet is not uniform there would likely be plants that capture the tax credit value as a windfall, without actually needing it to justify continued operations.

Carbon Price

Because of the low-carbon attributes of nuclear-generated electricity, a price on carbon emissions could potentially benefit existing nuclear power plants if the carbon price were reflected in wholesale electricity prices.[89] However, the design of such a carbon price policy could determine whether or not existing nuclear power would be financially advantaged. A carbon price policy could take many forms, including a carbon tax, a cap-and-trade approach, or an environmental regulatory approach such as the Clean Power Plan (CPP).[90] A carbon tax would place a value on carbon emissions that, all else being equal, would increase the cost of producing electricity from carbon emitting fuels.[91] To the extent that such costs are included in marginal-unit price offers from coal and natural gas generators, a carbon tax could effectively increase wholesale market clearing prices that determine electricity sales revenue for existing nuclear power plants.

However, a regulatory approach such as the CPP, which would likely result in an effective carbon price in many states, may have varied effects for existing nuclear facilities, depending to some degree on whether states achieve CPP compliance with a rate-based or mass-based target. A CPP rate-based standard (metric tons of carbon per megawatt-hour of electricity generation) does not include existing nuclear in the calculation of megawatt-hours. Therefore, if an existing nuclear plant closes, there will be no change in a state's carbon emissions rate under the rate-based approach. Under the rate-based standard, replacement of an existing nuclear plant with a gas-fired plant could reduce a state's calculated emissions rate, if the emissions rate from the new gas-fired capacity were lower than the state average.

By comparison, states using a mass-based approach would likely have a stronger incentive to maintain existing nuclear power. Under a mass-based approach, if an existing nuclear plant shut down and was replaced by gas-fired generation, the total carbon emissions in the state would rise,

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[87] For additional background, see CRS Report R43453, *The Renewable Electricity Production Tax Credit: In Brief*, by (name redacted) .

[88] For additional background, see CRS In Focus IF10479, *The Energy Credit: An Investment Tax Credit for Renewable Energy*, by (na me redacted) .

[89] Regional carbon markets, such as RGGI and California's Cap-and-Trade program, exist in the United States. These markets were not specifically designed to support nuclear power plants, and the existence of such markets has not provided sufficient incentives to relieve the financial stress encountered by plants that operate within those market regions.

[90] Implementation of the Clean Power Plan has been stayed by the Supreme Court. For more information see CRS Report R44341, *EPA's Clean Power Plan for Existing Power Plants: Frequently Asked Questions*, by (name red acted) et al. Additionally, President-elect Trump has stated that his administration will eliminate the CPP. For more information, see https://www.greatagain.gov/policy/energy-independence.html.

[91] For additional background on a federal carbon tax, see CRS Report R42731, *Carbon Tax: Deficit Reduction and Other Considerations*, by (name redacted), (name redacted), and (name redacted) .

making it more difficult for a state to achieve its CPP reduction goals. According to EPA's analysis of the CPP, "existing nuclear generation could be slightly more competitive under a mass-based implementation than under a rate-based implementation, because the former tends to create more wholesale price support for those generators."[92]

Federal Power Purchase Agreements (PPAs)

Power Purchase Agreements (PPAs) established between at-risk nuclear power plants and federal agencies are a policy option that could potentially provide a degree of electricity price certainty for both parties. PPAs have been used by the federal government to purchase power from renewable electricity projects over multiple years.[93] A federal agency could potentially contract with a nuclear plant to purchase power at an agreed-upon price over a multi-year period. One possible contractual mechanism might be a Contracts for Difference (CfD) contract model. A CfD contract essentially sets a price level for electricity and requires/entitles the parties to make up the difference between the actual market price and CfD contract price. This contract structure provides price certainty to both the buyer and the seller while eliminating the requirement to physically deliver nuclear electricity to a federal facility.

State-Level Policy Action to Support Existing Nuclear Power Plants

In some states where nuclear power plants have indicated their intent to shut down as a result of challenging financial conditions, state-level agencies and legislatures have taken action to provide financial support for existing nuclear plants. Generally, the motives supporting such actions include the contribution of nuclear power to a state's carbon emission goals and the state and local economic and employment impacts that would result from the closure of an at-risk nuclear facility or multiple facilities. Three such states where policies to support existing nuclear power plants have either been instituted or proposed are Ohio, Illinois, and New York. Policy approaches in each state vary but have generally taken one of two forms: (1) a power purchase agreement that provides out-of-market payments to nuclear power generators, and (2) a premium paid to nuclear power plants that is designed to reflect the low-carbon attributes of nuclear electricity.

Ohio: An Electric Security Plan filed with the Public Utilities Commission of Ohio (PUCO) by First Energy included a power purchase agreement (PPA) with the Davis-Besse nuclear power plant and the W.H. Sammis coal-fired power plant. The plan was approved by PUCO on April 1, 2016. However, the PPA element of the plan was challenged based on FERC restrictions on wholesale power sales transactions between "a franchised public utility with captive customers and a market-regulated power sales affiliate."[94] FERC subsequently rejected the PPA and required First Energy to submit the PPA to FERC for approval prior to any PPA-related sales transactions.

Illinois: Exelon, the owner and operator of the Clinton and Quad Cities nuclear power plants in Illinois, has been advocating for the state to pass legislation for a Next Generation Energy Plan.[95] The plan includes several components, one of which is a Zero Emission Standard that would provide financial support to nuclear power plants in the state that are at risk of early retirement. The energy plan includes a Zero Emission Standard that creates a program to purchase zero emission credits (ZECs) from nuclear plants and pass along the ZEC acquisition costs to ratepayers.[96] On December 1, 2016, the Illinois General Assembly passed S.B. 2814, which included an amendment to create a ZEC program for nuclear power plants in the state.[97] The Illinois ZEC program is similar in nature to the New York program, as described below, with the ZEC value being based on the U.S. Interagency Working Group

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[92] Environmental Protection Agency, *Regulatory Impact Analysis for the Clean Power Plan Final Rule*, August 2015.

[93] U.S. Department of Energy, *Federal On-site Renewable Power Purchase Agreements*, http://energy.gov/eere/femp/federal-site-renewable-power-purchase-agreements, accessed November 4, 2016.

[94] Federal Energy Regulatory Commission, 155 FERC 61, 101.

[95] An overview of the Illinois Next Generation Energy Plan is available at http://www.nextgenerationenergyplan.com/about#page2.

[96] Bloomberg New Energy Finance, *US Nuclear Takes One Step Forward, Eight Steps Backward*, June 30, 2016.

[97] Complete text of SB2814 is available on the Illinois General Assembly website. See http://www.ilga.gov/legislation/99/SB/PDF/09900SB2814ham003.pdf.

social cost of carbon (SCC). The base SCC value is $16.50 per MWh and ZEC values are adjusted annually based on electricity prices and capacity payments that are applicable to nuclear power plants participating in the program.

New York: On August 1, 2016, the State of New York Public Service Commission (PSC) issued an order to adopt a clean energy standard (CES). Among several stated goals, including additional support for renewable energy deployment, the CES includes a ZEC requirement, which is an "obligation on load serving entities to financially support the preservation of existing at-risk nuclear zero-emissions attributes."[98] Under the ZEC requirement, the New York State Energy Research and Development Authority (NYSERDA) would purchase ZECs from qualifying nuclear facilities during the period April 1, 2017, through March 31, 2029, in two-year tranches. In order to qualify for ZEC purchases, nuclear facilities must demonstrate public necessity by opening their books and records for an assessment by the Commission. For the first two-year tranche, the ZEC price has been calculated—based on the U.S. Interagency Working Group July 2015 SCC equal to $42.87 per short ton—to be $17.48 per MWh.[99] For the remaining tranches, ZEC prices will be adjusted based on a formula that takes into account the social cost of carbon, baseline Regional Greenhouse Gas Initiative (RGGI) carbon values, and the forecasted price of electricity and capacity.[100] The ZEC requirement is targeted to provide financial support to three nuclear plants in upstate New York: (1) FitzPatrick, (2) Ginna, and (3) the two-unit Nine Mile Point facility. An annual MWh ZEC price cap is based on the four-year average cumulative production from these three plants. Additionally, the PSC order indicates that the 12-year duration of the ZEC program is contingent on the FitzPatrick power plant being sold and ownership transferred by September 1, 2018. Should the FitzPatrick plant not be sold by this date the PSC would determine a course of action, if any, for future ZEC tranches.[101] A suit was filed with the U.S. district court in the southern district of New York challenging the legality of the CES and ZEC program.[102]

[98] State of New York Public Service Commission, *Order Adopting a Clean Energy Standard*, August 1, 2016.

[99] Ibid. Both New York and Illinois use the same U.S. Interagency Working Group $/ton value for carbon emissions. However, each state uses multipliers and discounts to convert the $/ton value into a $/MWh value. This explains why the $/MWh values for each state is different.

[100] Ibid.

[101] Ibid.

[102] http://www.epsa.org/forms/uploadFiles/3D17B00000014.filename.ZEC_Complaint_File_Stamped_101916.pdf.

Appendix. Plant-level Analysis of Electricity Sales Revenue and Fuel and O&M Costs

Table A-1 below contains analysis of electricity revenues and fuel and O&M costs for 33 nuclear power plants operating in competitive power markets within the United States. For each plant, 2015 fuel and O&M costs are subtracted from electricity sales revenue. Both revenue and cost data used to perform this analysis are at the plant level, with revenues represented by the nodal electricity price paid to each power plant and plant-level fuel and O&M cost information as reported by third-party sources. The analysis in **Table A-1** is unique in that it compares plant-level electricity sales revenue with plant-level costs. Published material reviewed for this report included nodal electricity prices compared with industry average costs as well as plant-level costs compared with regional hub prices. Although this combination of plant-level data sets is a unique attribute of this analysis, nevertheless it provides a limited view of the financial state of U.S. nuclear power plants and does not consider other cash expenses such as capital expenditures or additional revenue sources such as capacity payments—where available—and PPA contracts. Additionally, CRS is not assessing whether or not plants are at risk of closure. Estimates included in the table indicate only whether or not electricity sales generate enough revenue to cover fuel and O&M costs. However, total plant-level profitability, and therefore the economic viability of each plant, can be influenced by other cost and revenue considerations that are not included in the estimates presented. Data-access limitations prevented CRS from performing such analysis for this report.

Table A-1. Plant-Specific Analysis of Electricity Sales Revenue and Fuel and O&M Costs

Dollars per Megawatthour

	2015	2016	2017	2018	2019
Clinton	(2.63)	(0.70)	(2.55)	(2.80)	(3.53)
Quad Cities	(4.46)	(7.32)	(3.08)	(3.19)	(3.92)
Pilgrim	11.04	(2.50)	8.13	7.95	7.90
Beaver Valley	5.22	0.69	3.75	2.78	1.53
Braidwood	2.76	(0.59)	3.30	3.05	2.85
Byron	(2.30)	(5.64)	(0.13)	(0.17)	(0.97)
Calvert Cliffs	17.10	8.07	12.06	11.18	11.09
Donald C. Cook	4.24	(0.60)	1.54	1.35	0.39
Davis-Besse	7.47	2.67	6.40	5.52	4.59
Dresden	3.93	0.68	4.43	4.16	3.95
Hope Creek	8.05	(0.68)	7.02	6.30	5.42
LaSalle County	4.74	1.27	5.18	4.97	3.97
Limerick	9.12	0.48	7.88	7.16	6.28
Oyster Creek	5.31	(4.63)	2.15	1.37	0.85
Peach Bottom	8.60	(0.73)	5.80	5.06	4.95
Perry	6.79	3.31	7.88	6.29	4.73

	2015	2016	2017	2018	2019
Salem	8.62	(0.08)	7.61	6.90	6.02
Susquehanna	8.77	(0.66)	5.50	4.76	4.65
Three Mile Island	4.29	(4.03)	2.16	2.18	1.95
Duane Arnold	(8.43)	(9.81)	(6.46)	(6.69)	(7.40)
Fermi	(2.96)	(6.28)	(1.95)	(2.82)	(3.72)
Grand Gulf	4.58	5.59	8.34	7.27	7.04
Palisades	(1.63)	(4.06)	(1.88)	(2.08)	(3.00)
Point Beach	1.01	(2.63)	(0.15)	(0.37)	(1.22)
FitzPatrick	0.40	(4.33)	1.16	1.38	0.11
Ginna	7.38	2.92	8.34	6.58	4.88
Indian Point 2	12.35	2.96	14.15	12.29	11.49
Indian Point 3	8.90	(0.60)	10.65	8.79	7.98
Nine Mile Point	1.34	(3.46)	2.05	2.28	1.00
Millstone	16.03	2.99	13.07	12.92	14.33
Seabrook	7.05	6.83	10.58	10.44	10.40
Comanche Peak	0.66	6.42	4.50	3.60	3.35
South Texas Project	0.25	6.23	4.48	3.46	3.22

Source: CRS, using third-party data for revenue and cost. Revenue per MWh represents nodal prices for each nuclear power plant that was provided by Bloomberg New Energy Finance as part of a July 2016 report, *Reactors in the Red: Financial Health of the US Nuclear Fleet*. O&M cost per MWh (including fuel) for each plant was from an October 2016 report by the R Street Institute, *Where Have All the Nuclear Plants Gone?*

Notes: Nodal prices from Bloomberg include forward electricity price projections through 2019, as of the date of the report. Electricity forward price projections can change over time. Fuel and O&M costs for each plant were only available for the year 2015. For the purpose of the analysis, it was assumed that fuel and O&M costs stayed at 2015 levels. Generally, indications are that fuel and O&M costs are in a narrow range from year-to-year. However, plant-specific fuel and O&M costs can vary and impact the estimates presented above. Negative numbers—indicated by parentheses—in the table suggest that fuel and O&M costs for the plant exceed the nodal electricity price.

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