

RFF REPORT

# Decommissioning US Power Plants

*Decisions, Costs, and Key Issues*

Daniel Raimi

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# Decommissioning US Power Plants: Decisions, Costs, and Key Issues

Daniel Raimi\*

## Abstract

In recent years, hundreds of large power plants have retired across the United States, with hundreds more nearing the end of their useful lives. At the same time, large-scale growth in natural gas, wind, and solar power is changing the nation's electricity mix. Although much research has been carried out on the decommissioning of nuclear power plants, far less work has examined what happens to plant sites when generating units that burn coal, oil, or natural gas are retired or when wind or solar facilities reach the end of their lives. This report describes the options faced by plant owners after a plant has been retired. It examines the costs associated with decommissioning different plant types and highlights key issues that present opportunities and challenges for generating companies, regulators, local governments, and communities. Key issues include the large costs of environmental remediation and monitoring for coal-fired power plants and their combustion residuals, whether companies in deregulated markets are adequately saving for decommissioning, state and local policies for wind and solar decommissioning, and the economic and fiscal impacts of decommissioning power plants in rural areas.

**Key Words:** power plant decommissioning, power plant retirement, decommissioning costs, coal combustion residuals

**JEL Codes:** H23, H32, H71, H77, Q28, Q38, Q40, Q48, Q52, Q58

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AROs asset retirement obligations

BLM Bureau of Land Management

CCRs coal combustion residuals

CERCLA Comprehensive Environmental Response, Compensation, and Liability Act

CSP concentrated solar power

ELT environmental liability transfer

GW gigawatts

MSA metropolitan statistical area

MW megawatt

NGCC natural gas combined cycle

NGST natural gas steam turbine

PCBs polychlorinated biphenyls

PV [solar] photovoltaic

RCRA Resource Conservation and Recovery Act

TVA Tennessee Valley Authority

## 1. Introduction

As of 2015, roughly 6,300 electric generating units aged 40 years or older were operating in the United States. These units represent roughly 350 gigawatts (GW) of electric generating capacity, or approximately one-third of the nation's total generating capacity. In the coming years and decades, many of the older units at these plants will retire, with important implications for electricity markets, investors, and communities where plants operate.<sup>1</sup>

At the same time, the generating fleet is changing, as the number of natural gas, wind, and solar plants grows rapidly. For wind and solar facilities, most utilities, regulators, and communities have virtually no experience decommissioning utility-scale installations. Although most of these facilities will operate for decades to come, understanding the key issues associated with decommissioning new power generation can help mitigate any negative impacts for ratepayers, investors, and communities.

Once units retire, plant owners are faced with choices over how to repurpose each site. This report examines key issues that arise when owners decide to decommission an individual unit or an entire plant, including the following: What choices do plant owners face? What policies and market incentives affect each option, and how do they vary across states? What are the costs of decommissioning, and who bears them? What are the local economic and fiscal implications of decommissioning power plants?

Because a rich literature exists examining decommissioning issues associated with nuclear and conventional hydroelectric plants, those sources are excluded from this analysis. Instead, it focuses on those that have recently experienced large-scale retirements (coal, petroleum, and natural gas), along with those that are currently seeing widespread deployment (wind and solar) and will face decommissioning in the decades to come.

### 1.1. Structure of This Report

This report begins with an overview of recent power plant retirements in the United States, along with a brief analysis of where future retirements are likely to occur in the coming decades. Section 3 offers a framework to describe key decision points for power plant owners after a plant retires, discussing the rationale and risks behind each major option. Section 4 describes the cost of decommissioning for different fuel types by aggregating hundreds of cost estimates, primarily from regulatory filings. This section examines the key cost drivers for decommissioning plants of each fuel type and identifies areas where existing accounting protocols may not reflect the true costs of decommissioning. Section 5 synthesizes and discusses in detail the key issues facing plant owners, regulators, and communities as they consider how to decommission retired facilities. The discussion focuses on three topics: (1) how planning for decommissioning costs varies across market structures (i.e., traditionally regulated versus deregulated states); (2) the potential economic and fiscal

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<sup>1</sup> Throughout this paper, *units* refers to individual generating units such as natural gas combustion turbines, coal-fired boilers, or individual wind turbines. *Plants* refers to the facilities where these individual units are located, often including multiple generating units and incorporating transmission equipment, fuel processing facilities, and other infrastructure. The bulk of this analysis focuses on the retirement of plants.

impacts for communities where decommissioning occurs; and (3) the differences between decommissioning plants in rural and urban locations. Section 6 concludes and offers suggestions for future research.

## **1.2. Key Findings and Recommendations**

### **1.2.1. Key Findings**

- Hundreds of large power plants have retired in recent years, and hundreds more will retire over the coming decades. Planning properly for the decommissioning of these facilities is essential to minimize negative impacts to local environments, economies, electricity ratepayers, and taxpayers.
- Partly because of recently enacted federal regulations, decommissioning of coal-fired power plants and management of waste materials will be more costly than most had anticipated. A 2009 study estimates that closing all the nation's 155 "wet" ash impoundments would cost roughly \$39 billion over 10 years, and billions more will likely be needed for long-term monitoring and remediation. Existing decommissioning savings funds may not be sufficient to manage these costs for some utilities.
- In certain locations, particularly in some states with deregulated power markets, no local, state, or federal policy ensures adequate funding for decommissioning. In these locations, plant owners may not be adequately saving for decommissioning, potentially exposing shareholders, ratepayers, and/or taxpayers to unanticipated costs in the coming years.
- When power plants are sold, environmental liabilities typically transfer to the new owner. However, if the new owner goes bankrupt in the future, environmental liabilities may revert to the original plant owner if they are not fully addressed in bankruptcy proceedings. This issue will tend to arise more frequently in states where decommissioning funds are not accrued in advance of plant retirement.
- Full decommissioning often involves extensive environmental remediation, the costs of which are uncertain until work has begun. This may incentivize some plant owners to delay decommissioning and its associated costs, in some cases for years, which could lead to increased environmental damage as plant conditions deteriorate.
- Decommissioning of power plants has important economic and employment implications in the communities where they have operated. Although the decommissioning process requires dozens of temporary workers, the retirement of a power plant can displace hundreds of long-term employees.
- The local fiscal implications of decommissioning can also be significant. In some regions, particularly sparsely populated rural areas, large power plants can make up a sizable portion of the local tax base. In these locations, decommissioning can substantially reduce revenues for local governments and school districts.
- Numerous federal, state, and local programs incentivize decommissioning and redevelopment of industrial property. These programs are often beneficial for communities where they occur but can shift the cost of decommissioning and remediation from shareholders and ratepayers to taxpayers.
- Although data on decommissioning costs are limited, on a per-megawatt (MW) basis, it appears that the highest decommissioning costs are for offshore wind and coal plants. Natural gas plants on average have the lowest decommissioning costs, followed by petroleum. Solar and onshore wind fall in between the two (Table 1).

**TABLE 1. DECOMMISSIONING COST ESTIMATES PER MEGAWATT OF CAPACITY**

Fuel type	No. of estimates	2016\$ (thousands)		
		Minimum	Mean	Maximum
Offshore wind	7	\$123	\$212	\$342
Coal	28	\$21	\$117	\$466
Concentrated solar power (CSP)	5	\$24	\$94	\$138
Solar photovoltaic (PV)	22	-\$89*	\$57	\$179
Onshore wind	18	\$2	\$51	\$222
Petroleum/petroleum + gas	19	\$2	\$31	\$103
Gas (various types)	28	\$1	\$15	\$50

\*Negative cost estimates indicate that the salvage value of plant materials exceeds decommissioning costs.

### 1.2.2. Recommendations

- To mitigate against large unplanned decommissioning costs, prudent policy would require plant owners to either: (1) provide adequate financial assurance for decommissioning before construction of a plant; (2) accrue decommissioning funds over the life of the power plant, or both.
- In some states, particularly those with traditional cost-of-service regulations, such policies are currently in place. In states where these policies are not in place, state governments and regulators could move to implement such policies for existing plants.
- Because plant owners have more information about historical environmental issues than do potential buyers, and because environmental liabilities may not be uncovered until after a plant is decommissioned, extensive due diligence by potential buyers is advisable.
- In locations where power plants provide a large share of the local employment or tax base, careful planning between the plant owner and state and local officials will be crucial to minimize negative economic and fiscal impacts of decommissioning.

## 2. Background

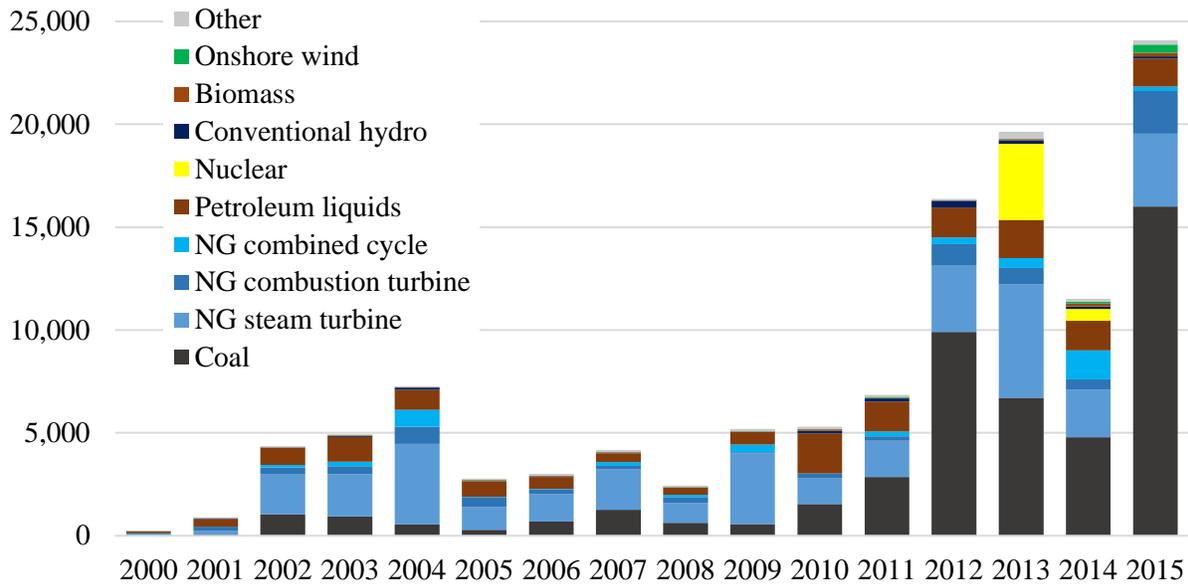
Since the year 2000, roughly 3,300 generating units totaling roughly 115 GW of capacity have been retired across the United States. The bulk of these retirements have come from coal (accounting for 40 percent of retired capacity), natural gas steam turbine (29 percent), and petroleum liquids (13 percent) units. Because petroleum liquid generators tend to be smaller than most coal- or gas-fired units, the greatest number of retired units (1,054) have been those fueled by petroleum, followed by 545 coal units, 372 natural gas steam turbines, and 310 natural gas combustion turbines (Table 2).

**TABLE 2. ELECTRICITY RETIREMENT SUMMARY STATISTICS BY FUEL TYPE, 2000–2015**

Unit type	Capacity of retirements (MW)	Number of units retired	Average age when retired	Average retired unit size (MW)
Coal	49,936	545	54	92
Natural gas (all)	42,513	995	38	43
Combined cycle	3,981	109	30	39
Combustion turbine	6,508	310	34	21
Combustion engine	307	204	37	2
Steam turbine	31,717	372	51	86
Petroleum liquids	14,677	1,054	38	14
Nuclear	4,188	5	35	838
Conventional hydro	1,281	174	70	8
Biomass	655	63	41	10
Onshore wind	565	37	15	15
Municipal solid waste	173	13	17	13
Solar PV	7	11	10	1
All other	1,106	396	40	12
<b>Total</b>	<b>115,103</b>	<b>3,293</b>	<b>40</b>	<b>35</b>

Source: Data from EIA (2016).

**FIGURE 1. CAPACITY OF UNITS RETIRED (MW)**



Source: Data from EIA (2016).

Note: In the early 2000s, a large amount of natural gas steam turbine capacity was retired, along with a substantial number of petroleum units. Since 2010, the majority of retirements have come from coal-fired plants, though retirements of natural gas and petroleum units have also been substantial.

Notably, retirement and decommissioning have different meanings. When a generating unit or an entire plant is retired, it no longer produces electricity. However, the assets of the plant, such as buildings, turbines, boilers, and other equipment, may remain in place. Decommissioning takes place only after a unit or plant retires and refers to the process of environmental remediation, dismantlement, and restoration of the site. Data on retired units are provided here because the US Energy Information Administration (EIA) does not collect data on the type and timing of decommissioning.

In recent years, coal retirements in particular have accelerated (Figure 1), driven by increased competition from low-priced natural gas, lower projections for future electricity demand, and to a lesser extent, environmental regulations (Burtraw et al. 2012).

### 2.1. Regional Trends

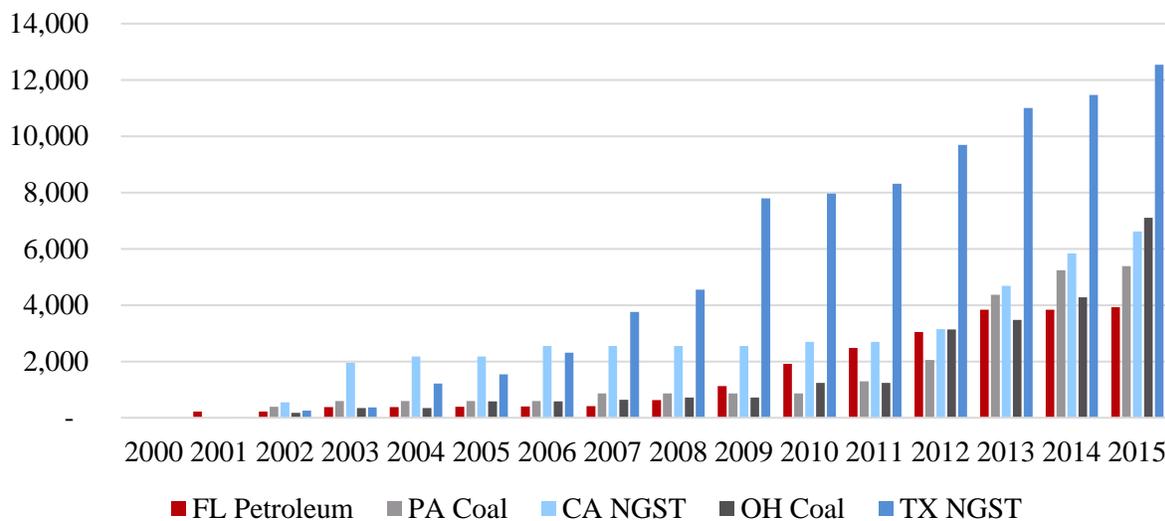
Among states, Texas has seen the most capacity retired (14,657 MW) since 2000. The bulk of these retirements have come from 62 natural gas steam turbines (NGST), totaling

12,224 MW of capacity. California is home to the largest number of retired units (299) and the second-greatest retired capacity (12,118 MW). As with Texas, most of California’s retirements (6,810 MW) have been NGST units. California has also seen 2,150 MW of nuclear capacity retired.

California and Texas are the two leading states for renewables retirement, with 441 MW and 64 MW of onshore wind retiring, respectively. Although little solar photovoltaic (PV) capacity has been retired to date (7 MW), the bulk of these retirements (6 MW) have occurred in California.

In Florida, the state with the third-largest number of retirements, 67 petroleum-fired units totaling 4,017 MW of capacity have retired, followed by 71 natural gas-fired units totaling just over 2,000 MW. Large-scale retirements of coal-fired units have occurred in over a dozen states, led by Ohio (7,518 MW), Pennsylvania (5,468 MW), and 15 other states with more than 1,000 MW of coal-fired retirements. Figure 2 highlights the states and fuels where the most retirements have occurred since 2000.

**FIGURE 2. CUMULATIVE RETIRED CAPACITY (MW) FOR SELECTED FUELS IN SELECTED STATES**



Source: Data from EIA (2016).

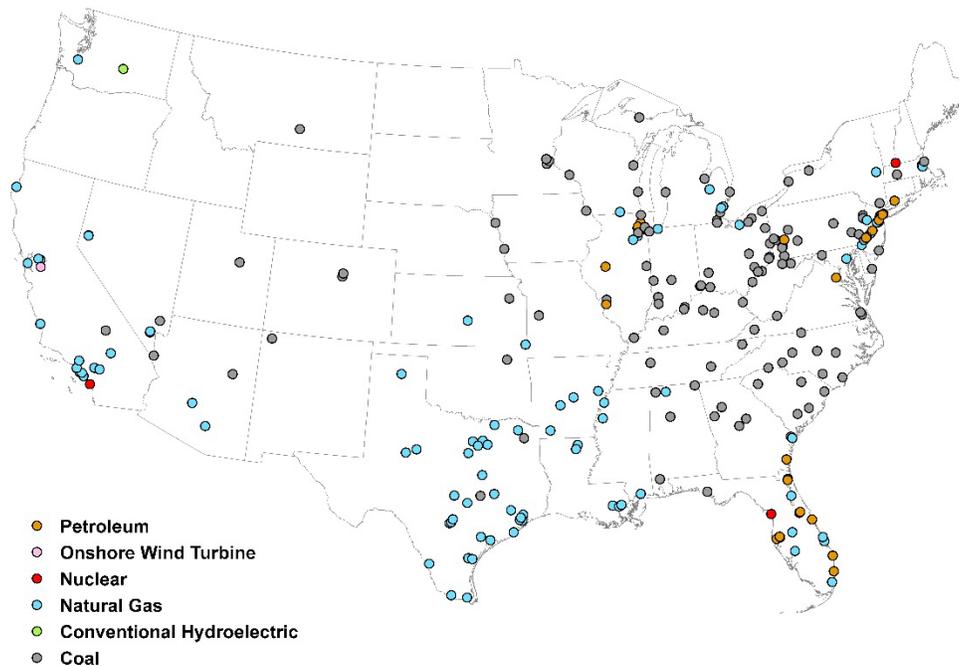
Note: This figure highlights the most substantial retirements by state and fuel type, showing that the largest single source of retirements since 2000 has been natural gas steam turbines (NGST) in Texas. Retirements have also been driven by coal in Ohio and Pennsylvania, NGST in California, and petroleum units in Florida.

Figure 3 provides a nationwide overview of plant retirements since the year 2000, mapping just those plants where generating capacity exceeded 100 MW. Along with the trends highlighted above, the figure illustrates the prevalence of coal-fired retirements in the Midwest and Southeast and the retirement of petroleum-fired plants in Florida, New Jersey, and New York.

Looking forward, the oldest operating power plants follow similar geographic and fuel-specific trends. Figure 4 shows all operating fossil fuel-fired plants that are 40

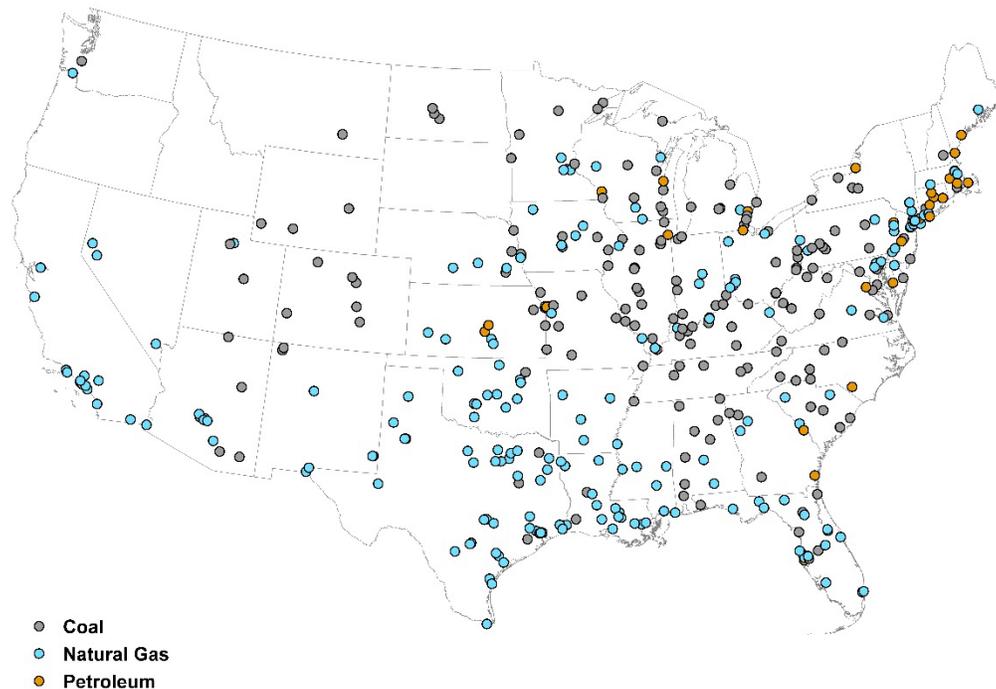
years old or older, with most aging coal plants concentrated in the Midwest and Southeast, while older petroleum plants are located primarily in the Northeast. Older natural gas plants are distributed broadly across the United States but show concentrations in Texas, California, Oklahoma, the Northeast, and along the Gulf Coast. The figure does not show nuclear or hydroelectric plants, as they are not the focus of this report, nor does it show wind or solar facilities, as just one wind facility and zero solar plants are older than 40 years.

**FIGURE 3. POWER PLANT RETIREMENTS (>100 MW), 2000–2015**



*Source:* Data from EIA (2016).

*Note:* This figure shows where large plant retirements have taken place from 2000 through 2015 and highlights the prevalence of natural gas retirements in Texas and California, coal retirements in the Midwest and Southeast, and petroleum retirements in Florida and the Northeast. Some plants use multiple fuels. Plants with any nuclear or coal units are labeled as such. For facilities with both petroleum- and gas-fired units, the plant is labeled according to which fuel source provided the dominant generating capacity.

**FIGURE 4. OPERATING COAL, GAS, AND PETROLEUM PLANTS 40 YEARS OR OLDER (>100 MW), 2015**

Source: Data from EIA (2016).

Note: This figure shows the location of large fossil fuel-fired power plants aged 40 years or older. It highlights the broad distribution and large number of plants that will need to be retired in the coming decades, with particular concentrations of natural gas in Texas, California, Oklahoma, the Northeast, and along the Gulf Coast; coal plants in the Midwest and Southeast; and petroleum plants in the Northeast. Some plants use multiple fuels. Plants with any nuclear or coal units are labeled as such. For facilities with both petroleum- and gas-fired units, the plant is labeled according to which fuel source provided the dominant generating capacity.

### 3. Key Decisions

Perhaps the most important single decision associated with decommissioning is how the plant site will ultimately be used. For example, when plants are located in city centers or near other amenities that create strong demand for land, financial incentives encourage owners to either sell the site or fully decommission and remediate for residential, commercial, or industrial development. For plants located in rural areas or other locations with weak demand for land, owners have less financial incentive to fully decommission and remediate a site, sometimes resulting in extended periods of the facility sitting idle. In other locations, preexisting access to natural gas pipelines, electricity transmission, or other infrastructure

may incentivize owners to repower (i.e., construct new generating units) at the site.

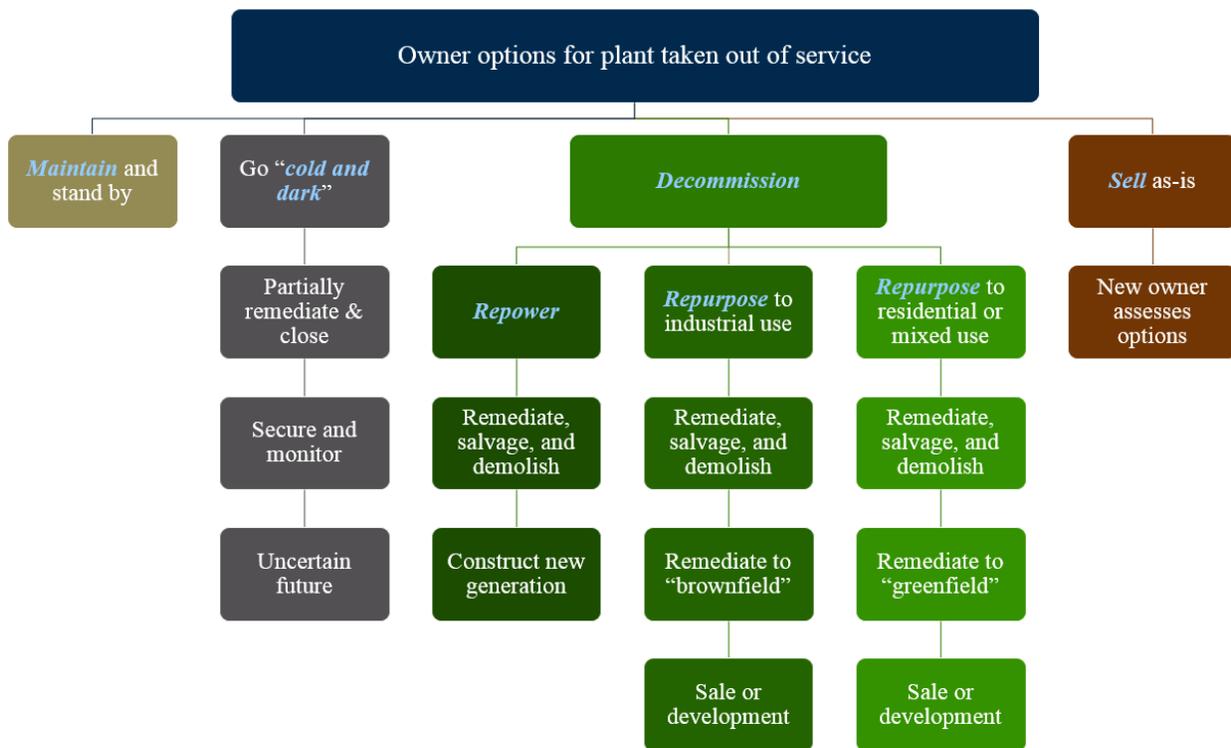
Regardless of location, plant owners will assess the value of their existing assets alongside the costs they may face under each of the four options described below and presented in Figure 5.

1. Maintain the plant for potential restart. If not restarted (or after restart), the owner ultimately decides from the other three options. With proper maintenance, plants can be kept in this condition for years.
2. Take the plant to a “cold and dark” condition. Under this option, the owner conducts limited environmental remediation and perhaps partial demolition, then retains and secures the site. The bulk of the facility is left as-is, with an uncertain future. The plant owner

- retains environmental liabilities and financial obligations.
3. Decommission and repower or repurpose the site. The desired end use of the facility will determine the extent of demolition and environmental remediation.
  4. Sell the plant as-is. Depending on the condition of the units, other structures,

and the site itself, the plant owner may find a buyer who will decide how and when to repurpose the site. The new owner assumes environmental liabilities and financial obligations associated with the site. However, if the new owner goes bankrupt in the future, environmental liabilities could revert to the original plant owner.

**FIGURE 5. DECOMMISSIONING DECISION TREE**



### **3.1. Assess Options for Decommissioning**

Once an owner has decided to retire individual units or an entire plant, the decision of how to decommission will depend on the potential value of the assets, including plant equipment, transmission equipment, land, permits, and other assets. Owners must also evaluate and consider the costs of remediating environmental issues, along with the risks of potential future liability associated with those environmental concerns.

To thoroughly assess their options, experts suggest that owners examine five key areas that can vary substantially among plants:

1. Above-ground costs: those costs associated with managing regulated materials above-ground (e.g., asbestos, polychlorinated biphenyls (PCBs), mercury)
2. Below-ground costs: those costs associated with managing surface and below-ground environmental issues (e.g., coal pile, coal combustion residual impoundments, petroleum releases)
3. Demolition and land reclamation costs
4. Salvage value of plant equipment and scrap
5. Property value of site

Because power plant owners' area of expertise is producing electricity rather than developing property, they may have little appetite for conducting a detailed analysis on the potential for redevelopment at a given site. However, such an evaluation is essential to determine the potential opportunities and liabilities in each case, as conditions can vary widely from plant to plant.

### **3.2. Maintain and Put on Standby**

In some cases, plant owners may defer the decision of whether to retire a plant, instead idling the facility and ceasing the bulk of

operations, but leaving it with the ability to restart in a period of days or weeks. The plant would retain its environmental permits unless it undergoes major changes, in which case it may become subject to new regulations under US Environmental Protection Agency (EPA) guidelines, potentially requiring new permitting.

The plant is kept in good working order, and although it is not available for dispatch, routine maintenance would mean ongoing costs for the owner. In general, maintaining is not a decommissioning option, but instead a temporary period when the plant is neither operating nor in the process of being decommissioned. This may be a preferred option when substantial uncertainty exists surrounding issues such as electricity markets or environmental regulations, and owners are uncertain whether a given plant will be needed or profitable in years to come.

Once a unit or plant is put into this state, the owner may either restart or retire it, then follow any of the three options described below: sell as-is, go cold and dark, or decommission. The decision of whether to restart or decommission is similar to the set of issues plant owners face when deciding whether to keep a plant in service or retire it. Because the focus of this report is on the set of decisions faced by owners once they decide to decommission a plant or generating unit, it does not cover putting a plant on standby.

### **3.3. Sell As-Is**

Plant owners may wish to sell a plant as-is, the simplest of the four options examined here. Potential buyers of these properties are primarily those wishing to redevelop the site and use the location's existing assets. The buyers of the property will face the same set of decisions as the original plant owners but often bring different expertise to the redevelopment process.

As noted above, power plant operators are in the business of generating and selling electricity, not real estate development. In some locations, such as densely populated urban areas where land is valuable, real estate developers may seize on the opportunity to purchase a site, demolish the existing plant, remediate any contamination, and redevelop. Such developers will bring expertise in the local real estate market but are unlikely to have the experience of power plant owners with regard to managing environmental liabilities (see Section 3.3.1).

Power plants often have assets attractive to a range of developers. For those interested in residential, commercial, or mixed-use development, particularly in regions with strong real estate markets, the value of the land can be substantial. In addition, a plant's main buildings are sometimes local landmarks, sturdily constructed and offering appealing aesthetic traits such as aged brick and high ceilings.

For developers interested in light industrial activity such as logistics, plants often have access to transportation infrastructure such as highways, waterways, and rail lines. For heavier industrial purposes, power plant sites offer access to electrical substations. In addition, plant owners may be able to transfer valuable water rights or permits to new owners, lowering costs for new or modified industrial operations.

Some firms specialize in acquiring, decommissioning, and redeveloping industrial sites with environmental liabilities. These companies, known as environmental liability transfer (ELT) firms, typically have expertise in assessing and remediating industrial facilities, then repurposing those sites. Such sales typically are not overseen by state or federal regulators, though they may come under scrutiny if a sale occurs in the context of bankruptcy.

In some cases, ELTs will purchase a facility as-is and assume its environmental liabilities because the potential redevelopment value of the site exceeds the costs of remediation. In other cases, ELTs may be paid a fee by companies to take on the responsibility of a property and assume its environmental liabilities. For example, if a facility has an estimated redevelopment value of \$7 million and estimated environmental liabilities of \$10 million, an ELT may acquire the property in exchange for a \$3 million payment. Because ELTs often have more experience with environmental remediation than other buyers, their participation could improve sales terms for sellers.

### **3.3.1. Concerns Associated with As-Is Sales**

While the option to sell a power plant as-is offers the potential for speedy redevelopment, a number of issues may arise that can affect sellers, buyers, and communities. For sellers, the sale of a site and transfer of environmental liabilities may not absolve them of all future liability risk. For example, the postsale discovery of unanticipated environmental hazards may pose new liabilities for the previous owner. Under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), commonly known as Superfund, EPA can pursue claims against the owner at the time the environmental damage occurred. (It can also pursue claims against the current owner or others in the chain of title.) This financial risk points to the importance of a thorough presale examination of the property by the original plant owner.

Another risk arises if the plant buyer goes bankrupt or is otherwise unable to cover the costs of known environmental liabilities. While EPA or state authorities, or both, will pursue claims against the bankrupt firm if environmental remediation is needed, liabilities may return to the plant seller under CERCLA. This risk generally encourages plant owners to sell only to entities with large

financial assets that have little risk of entering bankruptcy in the foreseeable future, as plant owners would not want to see environmental liabilities returned to them. Community stakeholders such as local businesses and governments may also wish to see plant sites owned by well-capitalized firms, thereby reducing risks of blight or any further environmental degradation.

In some cases, local governments may have an interest in acquiring a site. Because they are typically well capitalized, there is little risk that local governments would be unable to manage the costs associated with environmental remediation. Governments may be in a position to acquire the site from plant owners at a low price, presenting opportunities for redevelopment as green space or other community development efforts. However, local governments may not be in a position to understand the extent of the environmental liabilities associated with these sites. If environmental remediation requirements are extensive, local taxpayers may ultimately bear the burden of cleaning up sites.

As one example, in 1990, the city of Allentown, Pennsylvania, received a 280,000-square-foot riverfront industrial facility from a local donor, who had bought the property years earlier for \$250,000. The city accepted the donation with the intention of redeveloping the structure and integrating it into a mixed-use development (Hernan 1990). However, environmental liabilities, among other issues, delayed the project for more than 10 years, with the costs of remediating the site

and rehabilitating the structure estimated at roughly \$17 million, according to press reports (Wittman 2003). Ultimately, the site was remediated and a museum constructed with \$12.4 million in state and federal contributions (Nerl 2002).

### 3.4. Go “Cold and Dark”

Under some circumstances, plant owners may choose not to sell or fully decommission, but instead partially decommission the plant and retain key structures. In these cases, some—but not all—equipment is removed and some environmental liabilities are remediated. The facility will typically be physically secured with fencing and other measures to prevent vandalism or theft and limit liability risks. Owners may also hire a security firm to monitor the location.

When a plant is “cold and dark,” the owner continues to carry the costs associated with property taxes and site security. According to one decommissioning expert, these costs are often in the range of \$1 million per year for a medium-size coal-fired power plant, depending on the design of local property tax laws (Malley 2017).

Table 3 shows the current status of 238 retired fossil fuel-powered generating units based on data from 22 states provided by an industry expert (the EIA does not track the status of retired plants). Of these 238 units, roughly 38 percent are currently cold and dark, 55 percent have been demolished, and no data is available for the remainder.

**TABLE 3. SELECTED RETIRED GENERATING UNITS BY STATUS**

Fuel type	Units retired	Cold and dark	Demolished	Uncertain
Coal	102	37	55	10
Natural gas	86	37	45	4
Petroleum	50	16	31	3
Total	238	90	131	17

Source: Data by email from Ed Malley, TRC Solutions, July 2017.

Examining these data (which are not comprehensive) shows that the greatest number of cold and dark units are located in New Jersey (37), Ohio (13), Pennsylvania (11), Indiana (7), and Illinois (6). The bulk of these units have retired since 2014. However, 9 units identified in this dataset have sat cold and dark for more than 10 years, raising concerns over blight and potentially loss of structural integrity.

Multiple factors may lead a plant owner to go cold and dark. First, there may be little interest in redeveloping the site, and the plant owner may not want to invest the capital needed to fully decommission the plant. In locations where land values are low, the potential return on such an investment may be small or negative. As discussed further in Section 5.1, this situation tends to arise more often in competitive power markets, as utilities in cost-of-service regions typically build decommissioning costs into their rate bases.

Another factor that may perversely incentivize going cold and dark is the presence of uncertain environmental liabilities. As discussed in Section 3.5, full decommissioning frequently involves extensive environmental remediation, the costs of which are often uncertain until work has begun. By leaving the plant cold and dark, owners do not uncover unanticipated environmental issues such as oil leaks, asbestos-containing materials, PCBs, and other hazards that must be remediated. As noted in previous reports focused on decommissioning power plants, the unanticipated presence of such environmental hazards is common (e.g., Armor 2004; Brown et al. 2017).

### **3.4.1. Concerns Associated with Going “Cold and Dark”**

Four major concerns arise when plants are left in this uncertain condition, two from the

plant owner’s perspective and two from the community’s perspective. First, the closure of a power plant can have significant local economic and social impacts in nearby communities (see Section 5.2). For plant owners, which are often leading employers in communities where they operate, the reputational risks of these negative impacts are substantial. In addition, reputational risks could be exacerbated if the plant, left cold and dark, physically deteriorates into a blighted state. Second, fully securing large sites such as power plants is difficult and costly. Despite efforts to secure a site, vandalism, theft, or other criminal activity may be difficult to prevent completely, particularly when valuable materials such as copper are present. Plant owners also remain liable for accidents that occur on the site. As the condition of the plant deteriorates over time, the risk increases that plant visitors (whether authorized or unauthorized) could slip or fall, leading to injuries.

From the community’s perspective, the risk of blight (as noted above) from a plant left cold and dark for a number of years may be substantial, lowering nearby property values and raising the risk of vandalism or other crime at the site. In addition, environmental damage from unremediated spills or leaching tends to increase over time. For example, leaks from petroleum storage tanks that have not been fully remediated could spread deeper into soil, increasing ultimate cleanup costs as well as risks to groundwater. Structural issues such as a collapsed roof could make a site more hazardous by releasing previously sequestered materials such as asbestos or lead.

Until recently, perhaps the most important long-term environmental risk associated with leaving a plant cold and dark was posed by coal combustion residuals (CCRs). Risks of ground and surface water pollution from wet or dry ash impoundments that are not closed or properly maintained will tend to increase

over time, as underground contaminants migrate. Recent regulations under the Resource Conservation and Recovery Act (RCRA) require that all CCR impoundments managing wet ash comply with detailed groundwater monitoring protocols, mitigating some of these risks. Any ponds found to be contaminating nearby groundwater will be required to close by 2019. However, CCR landfills that do not manage wet ash are not subject to these regulations unless they receive new CCRs after October 2015 (US EPA 2015). These legacy landfills could pose risks if not properly constructed or maintained. These regulations and their cost implications, which are substantial, are explored in Sections 4.1.3 and 4.1.4.

### **3.5. Decommission**

Full decommissioning indicates that generating units will be completely dismantled, and in most cases, other capital at the plant site such as fuel-processing facilities and transmission equipment will also be dismantled and closed. (If repowering occurs, some of this equipment may remain.) This option includes environmental remediation, though the extent of remediation will vary depending on the desired end use of the property.

In cases where plant assets clearly outweigh expected demolition and remediation costs, or in traditionally regulated regions where decommissioning costs are built into rate bases, owners will typically proceed with decommissioning. Depending on the value of the property and the extent of contamination, a site may be remediated to conditions that suit different types of development. For example, remediation costs may be prohibitive for restoring land to a “greenfield” (pre-project) condition where residential development might occur. In such cases, plant owners may choose to restore the site to “brownfield” condition, suitable for

development of an industrial facility or repowering.

#### **3.5.1. Deciding On An End Use**

Multiple factors go into deciding on the end use of a power plant site. Although no two plants are alike in terms of their liabilities and assets, several common principles guide the decision-making process.

##### *3.5.1.1. Location and Value of Land and Assets*

As noted above, some power plants have a variety of attractive features that encourage redevelopment of the site, whereas others offer less opportunity for profitable redevelopment. Chief among these factors is the physical location of the plant. This section provides a brief overview, and the issue is examined in depth in Section 5.3.

When plants are in locations with strong real estate markets, such as in growing cities or along attractive waterfronts, the value of land may be substantial. In these situations, if the plant owner does not wish to sell the site as-is, they will likely have strong financial incentives to quickly decommission the plant and remediate the site so that it can be redeveloped. In addition to the value of the land, power plant infrastructure such as buildings may be attractive to potential developers. In these cases, decommissioning will involve removal of key pieces of equipment but leave other structures, such as facades or entire buildings, intact.

Along with the characteristics of the plant itself, the location of the facility may provide attractive access to key infrastructure or transportation. For example, many retired and aging coal-fired power plants sit along rivers that offer access to shipping lanes and typically have ready connections to railways. Access to such infrastructure may be appealing for developers seeking to site new industrial facilities.

### 3.5.1.2. Access to Transmission and Market Factors

In some cases, access to electricity transmission and favorable market or regulatory conditions will encourage owners to repower the site. For example, Florida Power & Light (FPL), a traditionally regulated utility operating in Florida, has retired 14 petroleum-fired units totaling roughly 2,700 MW of capacity in recent years (US Energy Information Administration 2016). At many of those sites, FPL has installed new natural gas combined-cycle (NGCC) units, which, because of the low cost of natural gas in recent years, have reduced operating costs (NextEra Energy 2016).

Repowering efforts in some cases may be supported by federal policy. For example, in recent years, EPA has offered the RE-Powering America's Land Initiative, which encourages the development of renewable energy projects on contaminated sites. The program provides technical assistance, project guidance, and coordination with potential partners, though it does not offer direct financial incentives (US EPA 2016a). Through October 2016, the program had supported deployment of 190 projects represented 1.1 GW of capacity across 38 states. Most of these projects have occurred at landfill sites, but other brownfield sites also have been eligible (US EPA 2016b).

### 3.5.1.3. Costs of Different Options

The potential value of the factors discussed above must be weighed against the costs associated with different decommissioning options. As discussed in detail in Section 4, costs range widely because of a variety of factors, including location (urban or very remote plants will tend to cost more), extent of environmental remediation required, salvage value, and more.

Under all circumstances, some level of environmental remediation will be required,

and the desired end use of the site will ultimately determine the level of remediation undertaken by the plant owner. Owners may decommission a facility and (1) remediate the site to brownfield status and repower; (2) remediate the site to brownfield status, suitable for industrial development, and sell; or (3) remediate the site to greenfield status, suitable for residential or commercial development, and sell. Because it requires the greatest level of environmental remediation, the third option will tend to be the costliest.

Plant owners typically examine the costs and benefits of each of these three options, often consulting with law firms, demolition companies, and others with expertise on decommissioning. After determining the end use of the site, the owner will begin planning for execution. Key decisions during this stage include the selection of contractors to characterize on-site safety risks, hazardous and regulated materials, salvage value, permit issues, and structural issues. Owners also solicit bids from contractors to carry out environmental remediation, demolition, and waste management. Once dismantlement and remediation are complete, the owner (or contractor) closes out the project by conducting a final site assessment, closing out contracts and permits, and archiving records.

### 3.5.1.4. Local Stakeholders

Because of the major economic and, in some cases, cultural contributions of power plants to the communities where they operate, the decision of how to repurpose a plant site can have substantial impacts on a community's character and economic prospects. As a result, plant owners often have a reputational incentive to see the site redeveloped, whether by them or by another party. Plant owners and contractors may also seek to enhance community support by hiring local workers, engaging local labor leaders, or subcontracting with local businesses.

Regardless of the site’s end use, extensive engagement with plant employees and other local, state, regional, and federal stakeholders is cited by industry experts as an essential component of any successful decommissioning effort. In some cases, plant owners convene a community advisory board to keep stakeholders abreast of plans and developments, as well as to gather external feedback and address concerns as they arise (Electric Power Research Institute 2010a, b; Malley 2016).

### 3.5.2. Decommissioning the Plant

Once an end use has been determined, the plant owner develops and implements a plan for decommissioning. For many newer power plants, including most wind and solar farms, decommissioning plans are developed and approved by local or state authorities, or both, before initial construction of the project. But for older power plants, decommissioning plans must in most cases be developed and implemented after decades of operations. In addition, many older plants were constructed

using asbestos, lead paint, or other regulated materials, the handling of which has become more stringent over decades.

Broadly speaking, decommissioning consists of four major phases: site assessment, project planning, project implementation, and project closure. Based on previous experience, the Electric Power Research Institute has developed reports that guide plant owners by providing a great level of detail on establishing workflows to accomplish objectives (Electric Power Research Institute 2010a, b). Each step in the process involves extensive planning and dozens of individual steps. Table 4 summarizes key elements.

While all decommissioning activities involve the steps above, different plant types and desired end uses require different levels of activity, particularly with regard to environmental remediation and site restoration. The costs and implications of these issues for different fuel types are discussed in Section 4.

**TABLE 4. KEY DECOMMISSIONING STEPS**

<b>Site assessment</b>
Gather historical information
Conduct on-site assessment for detailed information
<b>Project planning</b>
Develop remediation and closure plan
Communicate with stakeholders
Develop contracts and select contractors
<b>Project implementation</b>
Asbestos removal and other above-ground environmental remediation
Equipment removal and salvage
Demolition and salvage
Below-ground environmental remediation
Waste removal and disposal
<b>Project closure</b>
CCR landfill/impoundment closure and monitoring (coal plants)
Site grading and restoration: brownfield or greenfield

Source: Adapted from EPRI (2010a, b)

### 3.5.2.1. Decommissioning to Brownfield for Repowering or Sale/Redevelopment

Because power plants have access to existing electricity transmission infrastructure and often other features such as rail connections, natural gas pipelines, or access to water bodies for cooling, plant owners have opted to repower in many cases, decommissioning older generating units, then constructing new units at the same site.

After decommissioning, repowering typically requires that a site is remediated to brownfield status. As defined by federal statute, a brownfield is “a property, the expansion, redevelopment, or reuse of which may be complicated by the presence or potential presence of a hazardous substance, pollutant, or contaminant.”<sup>2</sup> After decommissioning, major issues of concern for power plant brownfields include soil contamination from leaks of petroleum or other liquids, CCR-related soil or groundwater contamination, and the presence of asbestos, PCBs, lead, or other regulated materials.

If a brownfield property is sold, liability is transferred under CERCLA to the new owner, providing prospective purchasers with a strong incentive to conduct a detailed site assessment. However, if the site is to be repowered by the same owner, no liability transfer occurs, and a detailed environmental assessment becomes less necessary. Although such an outcome results in lower costs for the plant owner, it may also increase ultimate site cleanup costs if subsurface contamination becomes worse over time.

### 3.5.2.2. Decommissioning to Greenfield for Sale or Redevelopment

In some cases, plant owners may wish to remediate a plant site to greenfield status. While the concept of a greenfield is straightforward, the precise definition will vary depending on local government requirements. For example, decommissioning plans for most wind and solar farms require developers to restore the site to preconstruction conditions (see Sections 4.3 and 4.5). For older fossil-fired plants, greenfield status may instead indicate remediation of a site suitable for residential redevelopment, where the extent of environmental cleanup satisfies local requirements but does not return a site to preconstruction conditions.

Although in theory plant owners could take on redevelopment efforts at a greenfield site, most owners are not interested in moving away from their core business of producing electricity and toward commercial or residential development. As a result, greenfield sites typically are sold to developers with knowledge of local real estate markets or in some cases donated by the plant owners for use as parkland or other civic purposes.

## 4. Fuel-Specific Decommissioning Processes and Costs

The costs of decommissioning power plants vary widely based on a variety of factors (Figure 6). These include the extent of environmental remediation required to meet the desired (or regulated) end state, the physical location of the plant, and the potential salvage value of equipment and scrap. Generally speaking, costs increase

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<sup>2</sup> Small Business Liability Relief and Brownfields Revitalization Act, Public Law 107-118, Section 211, 107th US Congress (2002).

when environmental remediation needs are greater; when plants are in densely populated cities, highly remote areas, or other locations that create logistical challenges; and when salvage values (which are driven by prices in volatile metals markets) are low. Because they are often relatively modest in physical size, and because of the absence of fuel storage facilities or combustion residuals, solar PV and onshore wind facilities tend to have lower costs for decommissioning than other plants. Concentrated solar power (CSP) plants, which tend to be larger than PV facilities and are often located in remote regions, typically entail higher decommissioning costs. Natural gas and petroleum plants both show wide ranges, with costs generally scaling with plant capacity. Estimates for offshore wind tend to be relatively high because of the logistical challenges of decommissioning at sea, though costs remain highly uncertain because no US facilities have been decommissioned.

Finally, coal plants tend to show the highest overall costs because of their age, large size, and various environmental remediation requirements. In particular, the costs associated with managing CCRs are substantial and contribute to a large share of the cost estimates provided in Figure 6. However, each of these estimates was made before the implementation of EPA's rule on

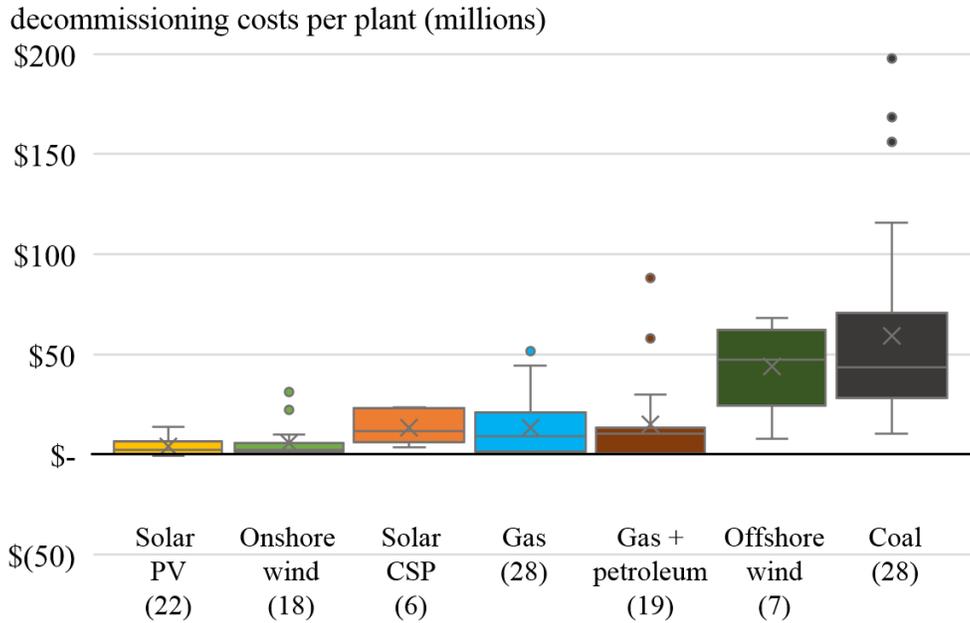
CCRs under RCRA and other state laws mandating the closure and monitoring of CCR impoundments and landfills. As discussed in more detail in Section 4.1, these costs are substantial, in some cases reaching \$200 million or more for a single large CCR impoundment. As a result, Figures 6 and 7 likely underestimate the ultimate cost of decommissioning coal-fired plants. Figures 6 and 7 use box-and-whisker plots to illustrate estimated decommissioning costs gathered from dozens of sources for 127 power plants.<sup>3</sup> Some estimates, such as those for projects on Bureau of Land Management (BLM) land, have been reviewed and approved by regulators. Others, including several wind and solar PV projects, are not subject to regulatory review and are therefore unverified estimates.

On a per-MW basis, the costs of decommissioning shift. The highest estimates for decommissioning come from offshore wind farms, where remote locations and offshore operations increase costs relative to onshore wind. Coal plants are also relatively costly to decommission on a per-MW basis, due largely to waste management costs and the need to remediate legacy environmental issues. Cost estimates are also relatively high for CSP plants, which are large-scale projects often sited in remote locations on federal land.

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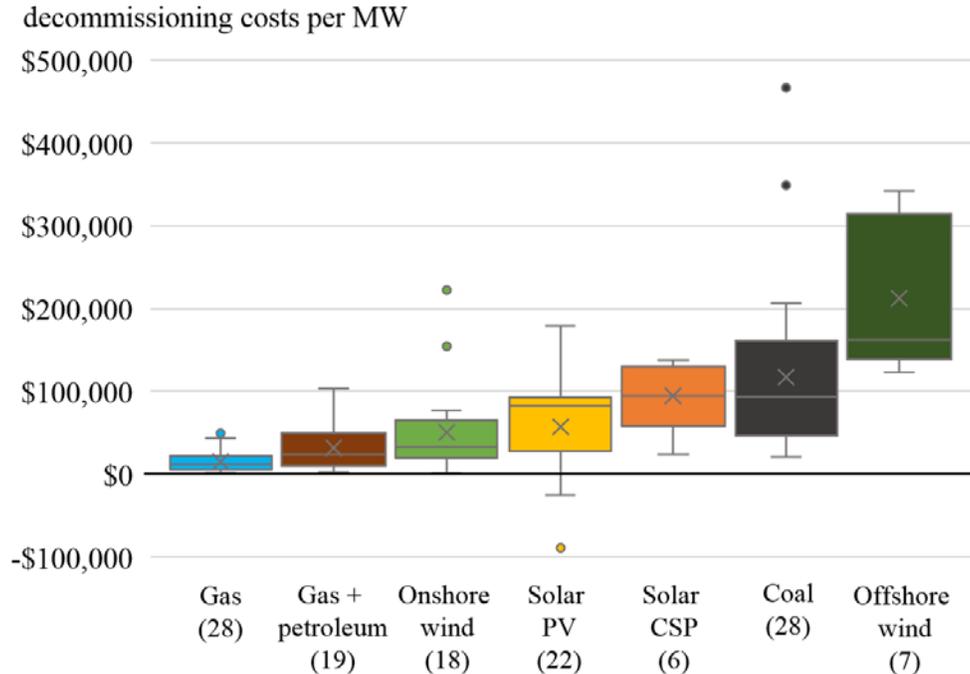
<sup>3</sup> In these figures, boxes represent the two central quartiles of the estimates, with an X marking the mean value and a horizontal line marking the median. Whiskers extend to the largest or smallest data point within 150 percent of the interquartile range (Q3 – Q1). Estimates beyond this range are shown as individual points.

**FIGURE 6. DECOMMISSIONING COST ESTIMATES FOR VARIOUS PLANTS (2017\$)**



*Sources:* Onshore wind: (EDP Renewables 2006; Ripley-Westfield Wind LLC 2010; State of Vermont Public Service Board 2010a, b, 2011a, b; EDP Renewables 2015a, b; McCarthy 2015; Algonquin Power Co. 2016; Invenergy 2016; State of Minnesota ND). Solar PV and CSP: (CH2MHill 2010; US Bureau of Land Management 2010-2016; Belectric 2011; EMC Planning Group Inc. 2012; Maryland Solar 2013; Michael Brandman Associates 2013; Apple One LLC 2014; Birdseye Renewable Energy 2015; RBI Solar 2015; Cypress Creek Renewables 2016; New York State Energy Research and Development 2016). Offshore wind: (Deepwater Wind 2012; Kaiser & Snyder 2012a; Levitan & Associates 2016). Solar PV, petroleum, gas (various), gas and petroleum, and coal estimates in Florida: (Progress Energy Florida 2009; Florida Power and Light 2016). Onshore wind, gas (various), and coal estimates in Colorado: (Burns & McDonnell 2014). Onshore wind, gas and petroleum, and coal estimates in Minnesota: (Xcel Energy 2015; Minnesota Power 2016).

*Note:* This figure shows the estimated decommissioning costs for a variety of plant types across the United States. Offshore wind estimates are based on preconstruction filings with state utility commissions and modeling exercises. Fossil plant estimates entail decommissioning and site remediation to brownfield status, suitable for industrial redevelopment. Wind and solar estimates entail decommissioning and site remediation to greenfield status, returning the sites to predevelopment condition.

**FIGURE 7. DECOMMISSIONING COST ESTIMATES PER MW OF PLANT CAPACITY (2017\$)**

Sources: See Figure 6.

Note: This figure shows the estimated decommissioning costs on a per-MW basis for a variety of plant types across the United States. Offshore wind estimates are based on preconstruction filings with state utility commissions and modeling exercises. Fossil plant estimates entail decommissioning and site remediation to brownfield status, suitable for industrial redevelopment. Wind and solar estimates entail decommissioning and site remediation to greenfield status, returning the site to predevelopment condition.

The cost estimates underpinning the figures above are drawn from specific jurisdictions where plant owners are required to submit cost estimates either when the project is built (most new wind and solar facilities) or when filing with public utility commissions to recover rates for decommissioning (in some cost of service regions). In competitive regions, plant owners are typically not required to file decommissioning cost estimates with state regulators (though they may be required to make these estimates for local jurisdictions when building new facilities). However, publicly listed plant owners assess the future cost of decommissioning plants as asset retirement obligations (AROs), often filed as part of an annual financial report (see Section 5.1.2.1). Although AROs provide some indication of expected future

decommissioning costs, they do not include plant-specific estimates, preventing detailed analysis.

#### 4.1. Coal-Fired Plants

In recent years, the largest amount of retired capacity has come from coal-fired plants, with 433 units representing more than 45,000 MW going offline since 2005. For the 911 coal-fired units that continue to operate in the United States, the average age is 43 years, with 298 units aged 50 years or older. As of 2015, 60 coal plants had announced planned retirement dates (US Energy Information Administration 2016).

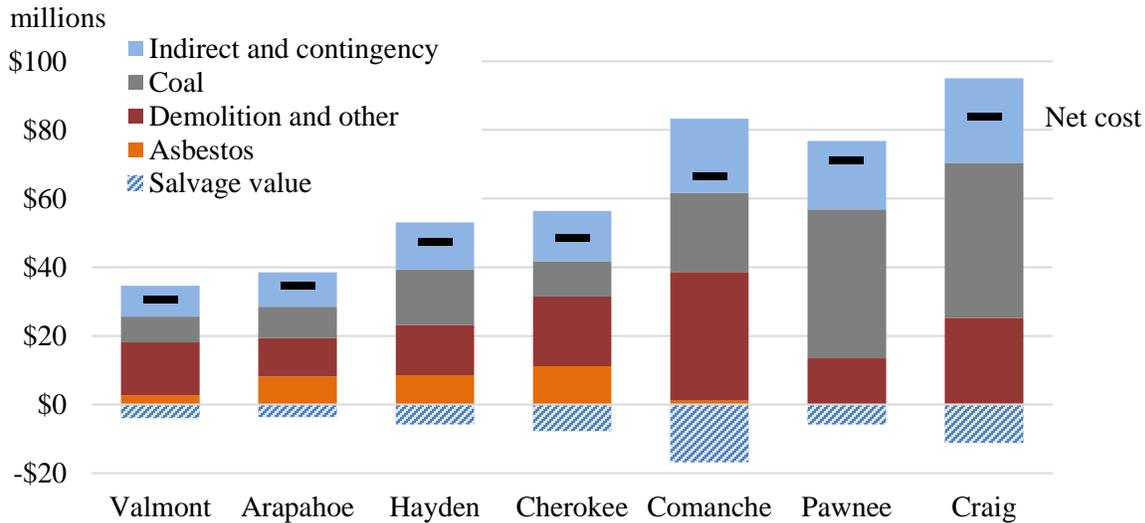
Because of the large number of coal plants retired in recent years, owners have invested substantial time in considering options for decommissioning. Once an owner decides to

retire a coal plant, perhaps the most important decision is how the site will be used in the future (see Section 3). Depending on this decision, the plant and site will undergo different levels of the following activities: pre-demolition environmental characterization and remediation, demolition and salvage, post-demolition remediation, and in many cases, long-term monitoring.

A variety of environmental concerns are associated with decommissioning coal plants, but the most substantial and most uncertain costs are typically from closing coal ash facilities. These costs are likely to increase in the coming years, largely as a result of the introduction of new federal regulations of CCRs under RCRA (see Section 4.1.4).

Figure 8 illustrates the leading cost components of decommissioning a selection of coal-fired plants. In some cases, particularly for older plants, predemolition environmental remediation such as asbestos abatement constitutes a large share of costs. Demolition and other costs vary widely from site to site and are typically driven by the complexities of safely demolishing smokestacks, boilers, and other large infrastructure. Management costs of CCRs and other coal-related environmental issues (such as cleaning up coal storage areas) can be substantial, in some cases exceeding 50 percent of total project costs. Finally, contractors typically include indirect costs (15 percent in the figure below), along with contingency funds to prepare for unanticipated environmental or other costs (20 percent in the figure below).

**FIGURE 8. ESTIMATED KEY COMPONENTS OF COAL DECOMMISSIONING FOR SELECT COLORADO PLANTS**



Source: Data from Burns & McDonnell (2014).

Note: This figure shows the key components of estimated decommissioning costs for a selection of coal-fired plants in Colorado. It highlights the wide variability in costs for demolition, salvage values, asbestos abatement, and coal residual management.

#### 4.1.1. Environmental Characterization and Remediation

When a plant is fully decommissioned, substantial time is invested in pre-demolition environmental remediation. This process begins with a detailed site characterization study, in which environmental hazards are identified and cataloged. These may include asbestos, PCBs, lead paint, hydrocarbon storage tanks, and contaminated soils, which must be removed, handled, and disposed of properly. As environmental standards have grown more stringent over time, remediation costs have increased. If environmental standards become more stringent in the future, delaying site remediation will tend to lead to higher costs (Oostdyk et al. 2017).

As Figure 8 highlights, asbestos abatement can be a major cost, adding \$10 million or more to some projects. Other costs, including remediation of soils affected by petroleum spills and disposal of PCBs or other regulated materials such as mercury, are also substantial.

#### 4.1.2. Demolition and Salvage

Plant owners hire contractors to plan for and implement demolition plans. These activities often begin with removing components that can be reused or sold for scrap, such as turbines or copper. In some cases, contracts specify that plant owners share in the proceeds from the resale of these materials; in other cases, contractors retain scrap revenues.

After valuable components have been removed, contractors will demolish key structures such as buildings and supporting infrastructure. Depending on the desired end use of the site, they may crush concrete foundations on-site and either remove or recycle the resulting waste streams. Smokestacks are often the final components to be demolished, and this tends to attract crowds

from the surrounding area. Although it is the most dramatic phase of demolition, stack demolition is typically less costly than other demolition activities, such as demolishing boilers or buildings. Along with the direct costs of demolition, each of these activities requires mitigation of the resulting dust or other materials, which can also be costly, particularly in urban areas where community concerns may be high.

After demolition, the remaining scrap metal will be removed from the site and sold to local purchasers. As discussed in more detail in Sections 4.3 and 4.5, scrap values can be substantial but are also volatile because of their connection with globally set metals prices.

#### 4.1.3. Coal Ash Management

As noted above, managing CCRs has become the costliest aspect of decommissioning many coal-fired power plants. During operations, CCRs generated by burning coal, which include fly ash and bottom ash, are stored in dry landfills or wet “ash ponds” at or near the plant site. In the wake of high-profile releases of ash from such ponds, along with evidence of groundwater contamination from unlined ponds (Harkness et al. 2016), EPA regulations finalized in 2015 now regulate CCRs under RCRA. These rules set standards for existing CCR impoundments, require the closure of ash ponds if they are contaminating groundwater, and require the closure of ponds or landfills that do not meet certain criteria, such as those that lack structural integrity or are in sensitive locations (US EPA 2015).

Wet CCR impoundments may be closed in two different ways. The first, closure-in-place, requires owners to first “dewater” the pond, then close the remaining landfill containing dry CCRs. (Closure of landfills is discussed below.) A key cost associated with this option

is managing the wastewater produced during dewatering (EOP Group 2009).

The second option for closing coal ash ponds also involves dewatering, followed by excavation of the CCRs and transportation to a landfill for ultimate disposal. This option tends to be costlier than closure-in-place because of the transportation costs of moving CCRs by rail or truck. As a result, closure-in-place tends to be the preferred option for plant owners, though in some cases, such as in North Carolina, excavation and removal of CCRs has been implemented following a high-profile release from an ash pond (Duke Energy Corporation 2017a).

A 2009 study commissioned by the federal Office of Management and Budget estimated that closing every one of the 155 wet ash impoundment in the United States through closure-in-place would include large capital, operating, and stranded costs, totaling roughly \$39 billion over 10 years (EOP Group 2009). For reference, \$39 billion represents roughly 10 percent of total revenue generated by electricity sales in the United States in 2016 (US Energy Information Administration 2017a). However, interviews with industry experts suggest that these costs may ultimately be higher because of monitoring and remediation requirements imposed by new regulations on CCRs under RCRA (see Section 4.1.4).

The costs of closing ash ponds vary for a number of reasons. First, groundwater conditions are different in each location; in some cases, groundwater movements may enhance the likelihood of CCR-related contaminants reaching a receptor (such as a private water well), potentially requiring costly remediation from the facility owner. Second, the operational needs of a plant may increase the costs of closure. For example, closing a CCR impoundment at a plant that continues operations will entail more logistical challenges than at a site where the plant is retired. Finally, the physical location of the impoundment affects costs. In some cases, ponds may be located in hard-to-reach locations, increasing logistical and transportation costs.

A series of studies carried out by the Tennessee Valley Authority (TVA) illustrates this range, with estimated closure-in-place costs ranging from \$3.5 million for a 22-acre pond to \$200 million for a 350-acre site (Tennessee Valley Authority 2016a, b, c, d, e, f). Excavation and removal of CCRs to landfills was estimated to cost between 270 and 2,200 percent more than closure-in-place for different sites. On aggregate and on per-unit terms, the costs of closure vary widely, as shown in Table 5.

**TABLE 5. COSTS OF CLOSURE-IN-PLACE AT SIX TVA WET COAL ASH IMPOUNDMENTS**

Plant name	Impoundment size (acres)	CCR volume (yd <sup>3</sup> )	Total cost	Cost per acre	Cost per yd <sup>3</sup>
Allen	22	250,000	\$3,500,000	\$159,000	\$14
Bull Run	38.5	3,500,000	\$13,000,000	\$338,000	\$4
Colbert	52	3,200,000	\$10,000,000	\$192,000	\$3
Sevier	42	770,000	\$13,000,000	\$310,000	\$17
Kingston	31	700,000	\$40,000,000	\$1,290,000	\$57
Widow's Creek	350	25,000,000	\$200,000,000	\$571,000	\$8
Total	536	33,420,000	\$279,500,000	\$521,942	\$8

Sources: Data from TVA (Tennessee Valley Authority 2016a, b, c, d, e, f).

Duke Energy, the nation's largest electric power utility, is currently closing all its CCR basins (both wet and dry) in the Carolinas. Due in part to state legislation enacted in 2016, a number of these basins are being excavated and removed to landfills, leading to higher costs per acre than closure-in-place.<sup>4</sup> Although Duke has not publicly issued estimated closure costs for these landfills, in 2016 it did report AROs associated with CCR basins in North and South Carolina of \$4.2 billion. For reference, Duke Energy Carolinas' net income in 2016 was \$1.2 billion (Duke Energy Corporation 2016). As Table 6 shows, these estimates imply closure costs of roughly \$1.6 million per acre, well above the average per-acre costs noted above for the TVA.

Dry ash landfills containing CCRs are typically closed by installing a cover system, such as liners topped with landscaping, which minimizes erosion and runoff. Modern landfills include underground protections to

prevent seepage and limit environmental risks to surrounding areas. However, some older CCR landfills do not have such protections and may pose increased risks to nearby groundwater resources.

Like coal ash ponds, closure of landfills containing CCRs can also be very costly. For example, landfill closure costs at one 1,270 MW coal plant in Florida were recently estimated at \$44.5 million, plus several million more for closure of smaller impoundments at the site (Florida Power and Light 2016). Another estimate from American Electric Power (AEP) for the closure of a 53-acre facility in Ohio estimates total costs of \$8.2 million (~\$154,000/acre). AEP also estimates costs of \$4.4 million over 15 years associated with maintenance of the landfill cover system, along with monitoring for contamination to groundwater, surface water, and other risks (American Electric Power 2016).

**TABLE 6. DUKE ENERGY ASSET RETIREMENT OBLIGATIONS AND COAL ASH IN THE CAROLINAS**

State	No. of ash basins (wet and dry)	Acreage	Ash volume (tons)	AROs	AROs per acre
NC	31	2,543	111,135,000		
SC	4	176	4,716,000		
Total	35	2,719	115,851,000	\$4.24 billion	\$1,559,765

Sources: Duke Energy (2016, 2017b).

Note: Duke Energy does not estimate state-specific AROs for North or South Carolina.

<sup>4</sup> Drinking Water Protection/Coal Ash Cleanup Act, Session Law 2016-95, House Bill 630, General Assembly of North Carolina (2016).

#### 4.1.4. Postdecommissioning Activities

After decommissioning and closure of CCR impoundments, hundreds of coal plant sites around the United States will require decades of monitoring and mitigation of any negative impacts to groundwater sources. Under EPA's 2015 CCR rule issued under RCRA (US EPA 2015), owners or operators of impoundments must install a groundwater monitoring system and complete the development of a groundwater sampling and testing program approved by a professional engineer by mid-2019. This program requires owners or operators to establish baseline groundwater quality levels (based on sampling from wells up-gradient of the impoundment), then monitor for statistically significant changes to water quality at down-gradient locations over the course of 30 years (statistical guidelines are provided in Section 257.93 of the rule).

Under the rule, owners or operators prepare annual groundwater monitoring reports, note results, and describe any

corrective action taken. If changes in groundwater quality are detected over this period, owners or operators are required to begin corrective action. Any such actions are required to protect human health and the environment, meet certain groundwater quality criteria, eliminate or mitigate the source of contamination, and remediate the affected area to the extent possible (Sections 257.97–257.98). Satisfaction of these criteria must be determined by a professional engineer.

Because these rules have yet to go into effect, and the long-term extent of contamination is uncertain, no reliable cost estimates exist for these monitoring programs. Impoundment closure costs cited above in Table 5 include the installation of groundwater monitoring networks, but because the long-term liabilities arising from any detections of groundwater contamination are unknown, the potential range of costs is large.

#### The Resource Conservation and Recovery Act (RCRA)

RCRA, passed by Congress in 1976, gives EPA authority to develop regulations related to hazardous and nonhazardous solid waste. States develop and carry out programs according to the guidelines established by EPA and may establish stricter regulations if they so choose. These guidelines include standards, monitoring, and corrective action protocols for municipal and industrial landfills, as well as “cradle-to-grave” requirements for hazardous wastes.

CCRs had not been subject to regulations under RCRA, though other fuel waste such as used motor oils have been regulated as hazardous wastes for decades. Other energy infrastructure such as underground petroleum storage tanks are also regulated under RCRA.

RCRA focuses on active and future sites, whereas abandoned or historical sites are the focus of the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), often referred to as Superfund.

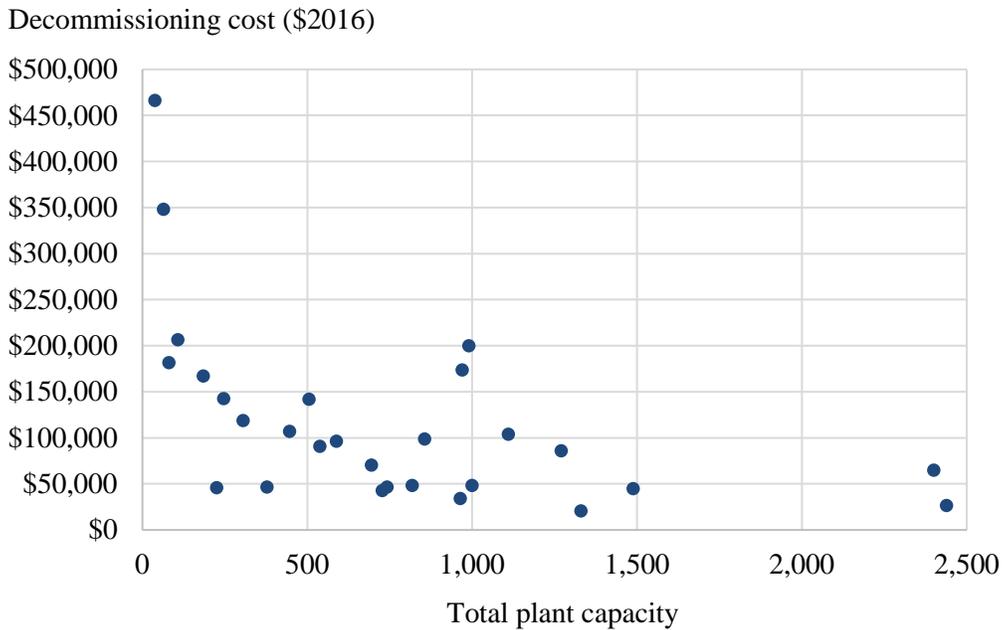
In 2010, EPA proposed to regulate CCRs under RCRA, examined several alternative approaches, and determined that it would regulate CCRs as nonhazardous solid waste, under subtitle D of the statute. After final publication of the rule in 2015, states began submitting management plans for approval to EPA, with the rule slated to take effect in late 2017. For more information on the rule, see <https://www.epa.gov/coalash/coal-ash-rule>.

### 4.1.5. Aggregate Cost Estimates

As demonstrated by the wide range of estimates, the costs of decommissioning a coal plant vary according to a number of location-specific factors. However, there is a correlation between the size of a plant and its decommissioning costs. As Figure 9 shows, larger plants tend to be less costly on a per-MW basis, as the incremental costs of

planning for, carrying out, and completing decommissioning tend to decrease with scale. In addition, a number of the smaller plants included in the figure are old compared with the larger, newer plants. As noted above, older plants often use more hazardous materials such as asbestos and may have treated CCRs less carefully, resulting in higher ultimate cleanup costs

**FIGURE 9. COAL DECOMMISSIONING COSTS BY PLANT SIZE**



Sources: See Figure 6.

Note: This figure shows estimated decommissioning costs for coal plants in select regions and highlights the correlation between plant capacity and per-MW decommissioning costs. In short, larger plants tend to be less costly to decommission on a per-MW basis. Figure does not include costs of compliance with 2015 EPA rules related to CCR management and monitoring.

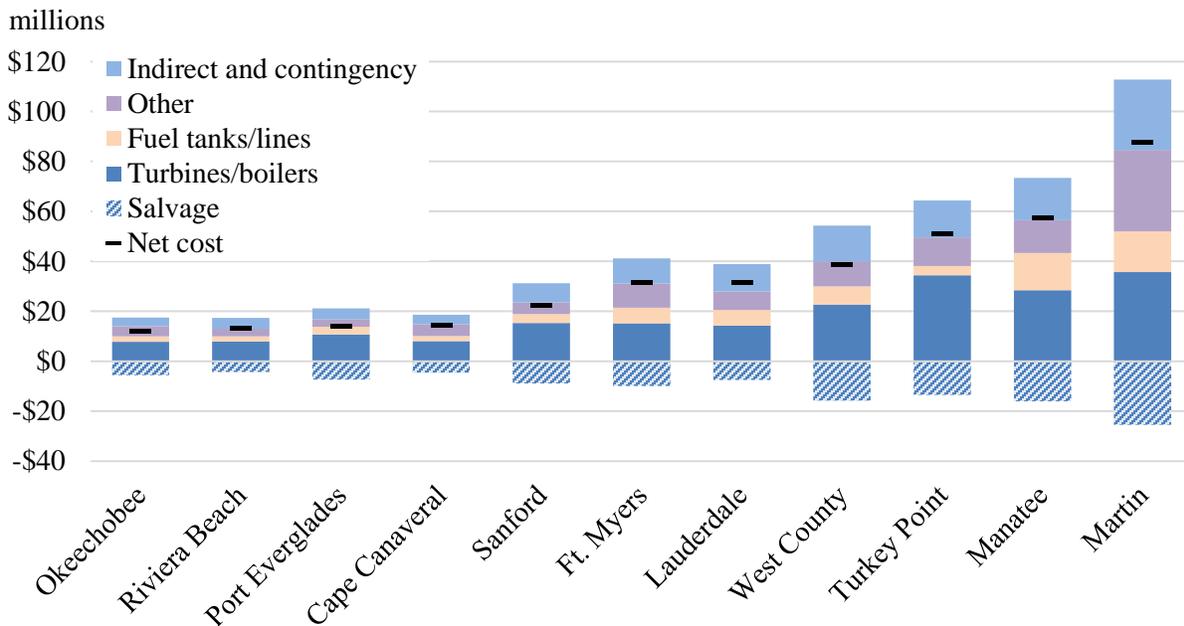
### 4.2. Natural Gas and Petroleum-Fired Plants

As noted in Section 2, the greatest number of recently retired generating units have been fueled by petroleum or natural gas. While recent years have seen a substantial increase in the number of NGCC units, less efficient types of natural gas generation, particularly NGST units, have seen increased retirements. Since 2005, 816 natural gas units and 791 petroleum-fired units have retired. On average, natural gas units have operated for 40 years before going offline, and petroleum units have averaged 38 years before retirement. As of 2015, 535 operating natural gas units (306 of which were NGST units) were aged 50 or older, and 133 (66 of which were NGST units) had announced retirement dates; 518 operating petroleum units were 50 years or older, with 42 having announced retirement.

Decommissioning gas and petroleum plants requires not only dismantling the generating units but also removing and managing fuel storage tanks, petroleum or gas pipelines, and other equipment at the plant.

Figure 10 highlights the major cost drivers for decommissioning petroleum and gas plants in Florida, where a large number of petroleum and gas retirements have occurred since 2000. Typically, the largest costs are associated with dismantling turbines (for gas plants) and boilers (for petroleum plants). The salvage value of scrap steel can be substantial, reaching above \$20 million for larger plants. Owners of both gas and petroleum plants also spend considerable sums cleaning and removing fuel storage equipment such as tanks and transportation lines. Finally, contractors add fees and contingency budgets to protect against unforeseen expenses.

**FIGURE 10. DECOMMISSIONING COSTS FOR SELECT GAS AND PETROLEUM POWER PLANTS IN FLORIDA**



Source: Data from FPL (2016).

Note: This figure shows estimated cost drivers for decommissioning natural gas and petroleum-fired power plants in Florida. It highlights that costs tend to be relatively uniform across different plant types and typically scale with plant size. Turkey Point estimates do not include nuclear power facilities.

### 4.2.1. Environmental Assessment and Remediation

The major steps of decommissioning a gas or oil plant are similar to those for a coal plant, but without the challenges associated with managing CCRs. Asbestos abatement costs for these power plants also tend to be lower than those of coal-fired plants, primarily because of their younger age. However, in some cases, older petroleum plants will contain substantial levels of asbestos, resulting in additional remediation costs amounting to millions of dollars. For example, the costs of asbestos abatement at several older petroleum plants in Minnesota are estimated at \$1.5 million to \$3 million (Minnesota Power 2016).

Natural gas and petroleum plants also require removal of fuel waste, though these costs tend to be less substantial than for coal-fired plants. For example, the dismantling, cleaning, and disposal of fuel oil storage tanks and other components was estimated to cost between \$5 million and \$17 million for several large natural gas and petroleum-fired plants in Florida (Florida Power and Light 2016). In some cases, leaking fuel storage tanks may create additional costs, as contaminated soil must be removed and properly disposed of.

### 4.2.2. Demolition, Salvage, and Postdemolition Activities

As noted above, the largest cost components for decommissioning natural gas and petroleum plants are often for dismantling turbine or boiler systems. The scrap metal generated from this equipment can be valuable, but it is not sufficient to offset demolition costs. Along with dismantling turbine and boiler systems, decommissioning involves breaking up and disposing or recycling concrete foundations.

Pipelines and storage tanks that are not removed may be retired in place. To retire this infrastructure, concrete is pumped in to seal off equipment and minimize risks of future degradation, similar to the “plugging” of abandoned oil and natural gas production wells.

Following the demolition phase, the plant site will be graded and restored to the desired end state. In most cases, long-term monitoring will not be required.

### 4.2.3. Aggregate Cost Estimates

Figure 11 shows the range of decommissioning costs for different plant sizes. There is little correlation between the size of a plant and its decommissioning costs on a per-MW basis. Neither is there a clear distinction between the costs of decommissioning gas-fired plants and petroleum-fueled plants. As noted above, older plants will be more likely to contain health hazards such as asbestos or lead paint.



longer blades and taller towers, increasing capacity factors relative to older, smaller turbines. As a result, repowered wind farms may result in greater output without an increase in land use. For example, a recent update to the Altamont Pass wind farm in California replaced roughly 1,500 smaller turbines with 82 larger units that provide the same amount of electricity, according to the American Wind Energy Association, an industry trade group (Hunt 2017).

#### **4.3.1. Landowner Agreements and Relevant Policies**

Unlike large, centralized power plants, whose owners typically purchased land on which to site their facilities, most wind farms are sited on land that is leased by the project developer. Although state and local governments often have requirements for decommissioning wind facilities, most modern leases also include provisions for decommissioning, providing the landowners some assurance that their properties will be returned to preconstruction conditions after retirement of the facilities.

Typically, leasing language stipulates that decommissioning occur within some reasonable time frame (e.g., six months) after all operations at the facility have ceased. Leases commonly require that all structures such as towers and turbines, concrete pads, and underground wiring are removed, followed by site grading and reseeding. In some cases, leases stipulate that the developer post a bond for the expected decommissioning costs. However, given the limited experience with decommissioning to date, it is not clear whether decommissioning is typically completed to the satisfaction of landowners or whether project developers have the financial

capacity to properly carry out decommissioning when a project reaches the end of its useful life.

Along with these private decommissioning terms, many local governments and some states require developers to prepare decommissioning plans and cost estimates when they submit permits to build a facility. In Connecticut, Ohio, and Oklahoma, legislatively established commissions require decommissioning plans and cost estimates prior to development, along with the establishment of financial assurance for ultimate decommissioning (Heibel & Durkay 2016). In New York State, similar requirements mandate wind farms with capacities of 25 MW or more to submit plans and expected funding requirements to a state board.<sup>5</sup> In other states, particularly in traditionally regulated regions, state utility commissions effectively require such planning by mandating that regulated power producers create and regularly update decommissioning plans, then recover the projected costs through rates (Progress Energy Florida 2009; Burns & McDonnell 2014; Minnesota Power 2016).

For projects on BLM land, developers submit decommissioning plans to the bureau before construction. These plans, which typically entail returning the site to greenfield condition, are reviewed and, if necessary, modified in accordance with BLM standards. The developer then provides financial assurance (typically a bond) based on the estimated decommissioning costs. Bond levels are reviewed by the BLM every five years to ensure adequacy (US Bureau of Land Management 2015).

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<sup>5</sup> Article 10 Regulations under the Power NY Act of 2011, Section 1001.29, New York State Board on Electric Generation Siting and the Environment (2011).

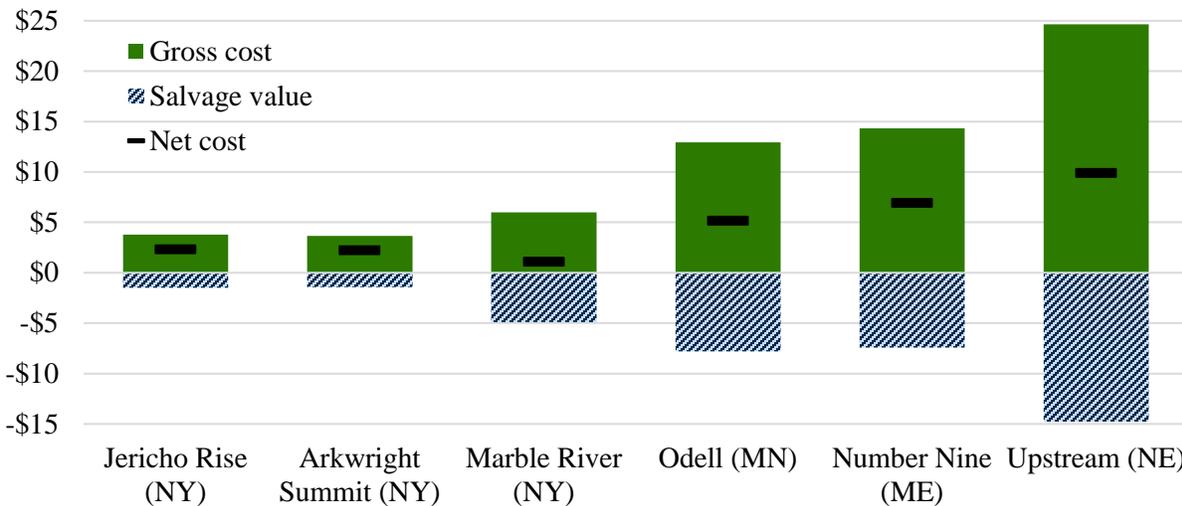
In states with deregulated electricity markets, or for independent power producers in traditionally regulated states, local governments such as counties are primarily responsible for permitting wind facilities, including decommissioning requirements. In some cases, local governments may not have the ability to set detailed standards for construction of these facilities. For example, the state of Texas is the largest wind power producer in the United States, with over 21,000 MW of installed capacity and nearly 12,000 active turbines (American Wind Energy Association 2017a). However, this

study found no evidence of local regulations pertaining to wind decommissioning in Texas. As a result, it is possible that not all wind developers in these regions have made financial preparations for decommissioning.

#### 4.3.2. Decommissioning Cost Estimates

One key element in the decommissioning of wind farms is the estimated value of scrap materials generated by dismantlement of towers and turbines. In many cases, plant owners estimate that the ultimate cost of decommissioning will be offset by 50 percent or more from the sale of these materials (Figure 12).

**FIGURE 12. DECOMMISSIONING COST ESTIMATES FOR SELECT ONSHORE WIND FARMS (MILLIONS)**

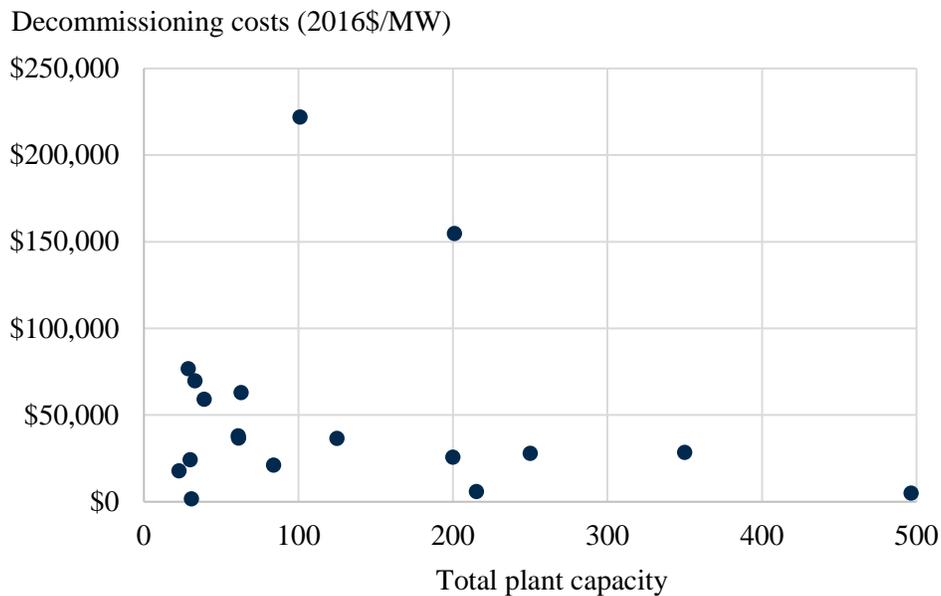


Sources: (EDP Renewables 2006, 2015a, b; Algonquin Power Co. 2016; Invenergy 2016; Patriot Renewables ND).  
 Note: This figure highlights the importance of salvage value for the net costs of decommissioning wind plants, with salvage values estimated to recover more than half the costs of decommissioning in some cases.

These estimates raise concerns over whether project developers are adequately accounting for future decommissioning costs. Prices for steel and other metals can be highly volatile, but the cost estimates cited above rely on commodity prices based on a single day (Algonquin Power Co. 2016) or an annual average (Invenergy 2016). In other cases, regulatory filings of developers do not provide sources for their estimates of commodity prices (EDP Renewables 2006) or state in these filings that values associated with decommissioning are unlikely to change substantially from year to year (EDP Renewables 2015a).

For decommissioning cost estimates that do provide salvage values, price estimates range from \$150 to \$236/ton. For a 215 MW wind farm, which includes 109 towers each weighing 200 tons (EDP Renewables 2006), this difference in expected prices for steel scrap implies salvage values ranging from \$3.27 million to \$5.14 million, a difference of \$1.87 million in net decommissioning costs. As Figure 13 illustrates, steel prices are volatile and have ranged from lows of near \$100/ton in 2009 to more than \$400/ton in 2012 (Steel Benchmark 2017). This range in steel prices implies a potential difference of \$6.54 million in the estimated net decommissioning costs for the hypothetical wind farm described above.

**FIGURE 14. ONSHORE WIND DECOMMISSIONING COSTS BY PLANT SIZE**



Sources: See Figure 6.

Note: This figure shows estimated decommissioning costs for onshore wind plants in select regions and highlights a modest correlation between plant capacity and per-MW decommissioning costs.

Although decommissioning costs for most projects are well below \$100,000 per MW, two plants in Minnesota show substantially higher costs. These higher cost estimates, prepared by the contractor TLG Services, appear to be driven by relatively high costs for grading and landscaping at the site following demolition and removal (Minnesota Power 2016). The underlying cause of these higher remediation costs is unclear.

#### 4.4. Offshore Wind

As of this writing, just one offshore wind farm, the Block Island project off Rhode Island, is operating in the United States. The decommissioning process for offshore wind projects tends to be more challenging and costly than for onshore projects. On a per-MW basis, decommissioning cost estimates for offshore wind projects are higher than for any other fuel type. These higher costs are driven primarily by the challenges of working in offshore environments, along with the costs associated with maritime transportation. In addition, offshore wind projects are often substantially larger than their onshore cousins, employing larger towers and turbines. However, because of the lack of experience with decommissioning of these facilities, domestic cost estimates are based on modeling and projections, rather than experience.

The major steps of offshore wind decommissioning include turbine removal, foundation removal, electrical cable removal,

scour protection (preventing damage to the seafloor), and salvage or disposal of materials (Kaiser & Snyder 2012b). Different types of turbine foundations will also incur different levels of decommissioning costs. Turbines may be driven directly into the seabed (such foundations are called “monopiles”) or may rest on foundations made of concrete, steel tripods, or other designs. A variety of other designs have been proposed, including floating foundations. For monopole or tripod designs, owners cut and remove equipment below the seabed using water jets, explosives, or other techniques. For concrete designs, underwater demolition is also required.

Costs for decommissioning will vary according to several key factors. First, facilities located farther from shore will be costlier to dismantle because of logistical requirements. In particular, the distance between equipment and onshore staging areas, rather than the mere presence of coastline, will play an important role in determining these costs. Second, facilities with older and less powerful turbines will generally have higher per-MW costs. Kaiser and Snyder (2012a) provide a useful example of these two factors by modeling costs for two 150-MW wind farms, one off the coast of Texas and another off the coast of New Jersey. As Table 7 shows, decommissioning of the New Jersey facility, which would employ smaller turbines and is located farther from the nearest serviceable port, is estimated to cost roughly twice as much on a per-MW basis.

**TABLE 7. DECOMMISSIONING COST ESTIMATES FOR TWO OFFSHORE WIND FARMS**

Wind farm	Capacity (MW)	No. of turbines	Distance to port (nautical miles)	Net cost (millions)	Cost per MW
Coastal Point (TX)	150	60	20	\$23	\$156,000
Garden State (NJ)	150	96	80	\$45	\$302,000

Source: Kaiser and Snyder (2012a).

#### 4.4.1. Federal Policies

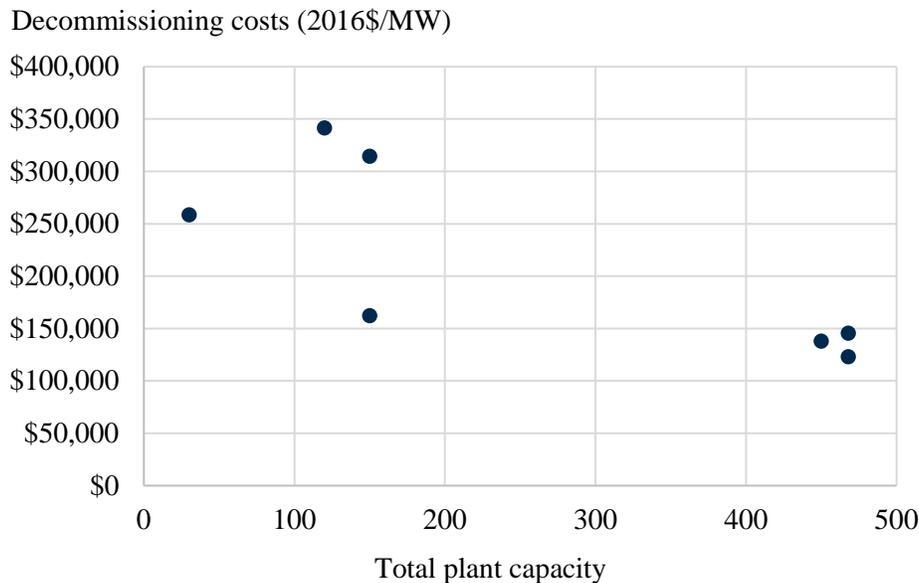
For wind farms constructed in federal waters, federal regulations require that operators begin decommissioning at the end of commercial operations, with all equipment removed within two years of the termination of the lease, right-of-way, or right-of-use grant. Federal waters begin 3 nautical miles from shore for most states and 9 nautical miles from the coast of Texas and the west coast of Florida (Bureau of Ocean Energy Management 2017). In federal waters, developers post a bond or other financial assurance based on estimated decommissioning costs. Federal rules require removal of all equipment at the surface, on the

seafloor, and up to 15 feet below the seafloor “mudline.” On a case-by-case basis, regulators may allow developers to leave certain infrastructure in place.<sup>6</sup>

#### 4.4.2. Decommissioning Cost Estimates

Figure 15 illustrates a range of estimated decommissioning costs for six proposed and one constructed offshore wind farm in the United States, showing that larger plants are generally less costly to decommission on a per-MW basis than smaller plants. However, given the limited experience with offshore decommissioning coupled with the small number of estimates available, it is difficult to say whether this correlation would hold under real-world conditions.

**FIGURE 15. OFFSHORE WIND DECOMMISSIONING COSTS BY PLANT SIZE**



Sources: See Figure 6.

Note: This figure shows estimated decommissioning costs for offshore wind plants in the United States. Because no offshore wind plants have been decommissioned in the United States (only one plant is currently operating), these estimates are highly uncertain and come from preconstruction filings with state utility commissions and modeling exercises.

<sup>6</sup> Renewable Energy Alternate Uses of Existing Facilities on the Outer Continental Shelf, 30 CFR 285, 43 U.S.C. 1331 and 1337 (2011).

#### **4.5. Solar Photovoltaic and Concentrated Solar Power**

Like onshore wind generation, utility-scale solar electricity generation has increased rapidly in recent years, growing from 550 GWh in 2005 to nearly 25,000 GWh in 2015 (though it accounted for just 0.6 percent of total generation in 2015) (US Energy Information Administration 2017b).<sup>7</sup> As of 2016, 1,734 utility-scale solar PV and 19 CSP plants were operating across 37 states. On average, PV facilities were just 3 years old, with CSP averaging 2.3 years (US Energy Information Administration 2016). The useful lives of most solar PV cells are expected to be 20 to 30 years.

Because few solar facilities have reached the end of their useful lives, industry experience with decommissioning these facilities is extremely limited. As a result, cost estimates for decommissioning solar sites are not based on experience, but instead are projections. Solar PV units, because they are often relatively small in terms of generating capacity, generally have lower decommissioning cost estimates than larger fossil-powered plants. However, CSP units are often quite large (>100 MW), resulting in higher overall cost estimates. On a per-MW basis, cost estimates for CSP facilities tend to be higher than those for solar PV. Both are higher on average than those for gas, petroleum, or onshore wind but lower than those for coal or offshore wind.

For both PV and CSP facilities, decommissioning involves three major steps: dismantling the equipment, managing the resulting waste streams, and restoring the site. In each of the decommissioning studies and regulatory filings reviewed for this study,

project owners are required to return the site to greenfield (i.e., preconstruction) condition.

Although there are some concerns associated with regulated materials from solar PV cells, the environmental remediation requirements for decommissioning these facilities is limited compared with those for older fossil-fired plants, which often require asbestos abatement and management of soils contaminated by hydrocarbons or CCRs. However, contractors handling waste streams from solar decommissioning must handle certain materials carefully and comply with relevant waste and recycling guidelines.

##### **4.5.1. Landowner Agreements and Relevant Policies**

When negotiating with landowners, solar developers sometimes include language related to decommissioning and site restoration in the lease agreement (Clark 2016). However, such language is not typically required by state or local regulations, and it is unclear how common decommissioning terms are in private lease agreements.

In locations where decommissioning cost estimates are required by local, state, or federal authorities, owners are also required to provide some type of financial assurance for this reclamation. For solar development on federal land, decommissioning plans and financial assurance are required by the BLM. Along with BLM requirements, 10 states have statewide policies on solar decommissioning, though most do not require financial assurance. For the 40 states without policies, rules and requirements may be applied by utility commissions or local jurisdictions (North Carolina Clean Energy Technology Center 2016).

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<sup>7</sup> Distributed solar power generated an additional 14,139 GWh in 2015, increasing solar's total share of the power mix to roughly 1 percent.

Developers in some regions may not be required to submit any decommissioning plans. For example, this study was unable to find evidence of decommissioning plans or financial assurance for dozens of solar PV projects currently in operation or under development across several counties in western Texas.

Managing waste streams from solar PV projects has the potential to be challenging because of the hazardous materials contained in solar cells, including cadmium, lead, and selenium. These issues will arise at the end of a project's life or if equipment is rendered unusable by high winds, hail, or other damage. If not properly disposed of, these materials may cause risks to the environment or human health, though existing research suggests that such risks are relatively modest (Sinha et al. 2014). A number of recycling programs will accept retired PV modules for no charge, but private incentives to recycle may not always be sufficient to induce this behavior (McDonald & Pearce 2010).

#### 4.5.2. Decommissioning Cost Estimates

Because PV and CSP facilities are composed of hundreds or thousands of individual modules, dismantling them is time- and labor-intensive.

Removing each module, dismantling its support structure, removing electrical wiring, and breaking up concrete accounts for the bulk of decommissioning costs in most cases. For example, one estimate of solar PV decommissioning costs prepared by the state of New York estimates that roughly 90 percent of costs arise from dismantling and removing equipment, while just 10 percent come from postdismantling activities such as site grading and restoration (Table 8).

In some cases, particularly in environmentally sensitive locations, the costs of land restoration are more substantial. For example, decommissioning plans for the Ivanpah CSP facility in California, which sits on federal land, involve costly site remediation programs, along with a 10-year monitoring and maintenance plan estimated to cost more than \$9 million (CH2MHill 2010). As with other power plants, the physical location of solar projects also plays an important role in ultimate decommissioning costs. Notably, projects in more remote locations (such as CSP projects in deserts) will tend to be costlier to decommission than projects in more densely populated regions because of high transportation costs and limited local labor supply.

**TABLE 8. ESTIMATED DECOMMISSIONING COSTS FOR A 2 MW SOLAR PV FACILITY**

Task	Estimated cost
Remove rack wiring	\$2,459
Remove panels	\$2,450
Dismantle racks	\$12,350
Remove electrical equipment	\$1,850
Breakup and remove concrete pads or ballasts	\$1,500
Remove racks	\$7,800
Remove cable	\$6,500
Remove ground screws and power poles	\$13,850
Remove fence	\$4,950
<i>Removal costs subtotal</i>	<i>\$53,709</i>
Grading	\$4,000
Seed disturbed areas	\$250
Truck to recycling center	\$2,250
<i>Postremoval costs subtotal</i>	<i>\$6,500</i>
<b>Grand total</b>	<b>\$60,209</b>

Source: NYSERDA (2016).

Table 9 shows a wide range of net costs for decommissioning these plants, with larger plants being more costly overall. However, there is not a clear pattern in terms of relative costs, with net costs per MW of capacity varying from \$177,000 to -\$88,000. As noted above, the drivers of these costs are typically location and the sensitivity of the natural habitat. In addition, similarly to wind farms, decommissioning costs for solar PV projects are substantially affected by the potential to recycle or sell equipment and scrap metal. The negative costs in the table indicate that the estimated resale value of scrap metal exceeds all decommissioning costs.

North Carolina, like most other states, currently has no statewide standards for the preparation of decommissioning plans or cost estimates. Large utilities in cost-of-service states such as North Carolina submit decommissioning plans to experts at state public utility commissions during rate cases. However, independent project developers are not required to submit such plans. Instead, they may not prepare decommissioning plans or may submit plans to local authorities such as county planning officials, who may not have the expertise or resources to adequately assess the plausibility of those plans.

A key difference between decommissioning cost estimates in North Carolina and other states examined in this study is that with the North Carolina projects listed in Table 9, developers assumed substantial salvage values for solar panels at the end of a project's life. Whereas other cost estimates assumed \$0 salvage value, these projects in North Carolina forecast hundreds of thousands of dollars in revenue from the salvage of solar panels. For example, one decommissioning plan for a 5 MW facility projects that the salvage value in 2065 (50 years after the project began operation) of 23,000 solar panels will be \$14 each, totaling \$316,000 (Apple One LLC 2014). Another plan for a 5 MW facility forecasts \$256,000 in salvage value from panels. In addition, this project's cost estimates for dismantlement are well below those of other, similar-size facilities in the area; does not include costs for site restoration; and bases its projected salvage value for steel and aluminum on market spot prices on a single day (RBI Solar 2015). In contrast, a 2017 regulatory filing by Duke Energy with the North Carolina Utilities Commission estimates \$0 salvage value for solar panels (Burns & McDonnell 2017).

**TABLE 9. NET DECOMMISSIONING COSTS FOR SELECT SOLAR PV PROJECTS**

Project name	State	Capacity (MW)	Net cost/MW	Net cost
Desert Sunlight 300	CA (BLM)	300	\$45,976	\$13,792,776
Desert Sunlight 250	CA (BLM)	250	\$50,992	\$12,748,075
Dry Lake	NV (BLM)	100	\$101,915	\$10,191,455
Quinto	CA	110	\$43,583	\$4,794,180
Vega	CA	20	\$177,000	\$3,540,000
Maryland Solar Park	MD	20	\$105,000	\$2,100,000
Luning	NV (BLM)	50	\$35,027	\$1,751,357
Fleshman/Kost Rd.	CA	3	\$73,333	\$220,000
NYSERDA estimate	MA	2	\$30,100	\$60,200
Longneck	NC	5	-\$1,253	-\$6,263
Rock Barn	NC	5	-\$24,902	-\$124,508
Sonne Two	NC	5	-\$84,676	-\$423,382
Apple One	NC	5	-\$88,076	-\$440,381

Sources: See Figure 6.

Note: All cost estimates include returning sites to greenfield condition.

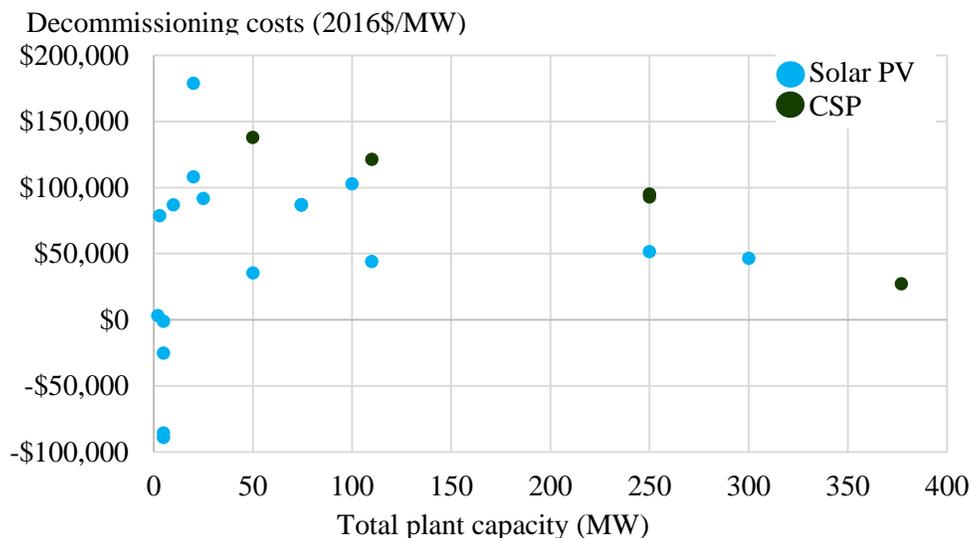
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Figure 16 shows the distribution of costs across a range of PV and CSP facilities. Although there is a modest negative correlation between plant size and decommissioning costs per MW, the limited amount of data and presence of negative estimates for plants in North Carolina makes it difficult to generalize.

**FIGURE 16. SOLAR DECOMMISSIONING COSTS BY PLANT SIZE**



Sources: See Figure 6.

Note: This figure shows estimated decommissioning costs for solar plants in select regions. It also shows several plants where project developers estimate negative net costs, with salvage values exceeding decommissioning expenditures. These estimates all come from solar PV projects in North Carolina and appear to be driven by optimistic assumptions about the resale value of solar PV panels on retirement. When these negative estimates are excluded, there is a clear negative correlation between plant size and decommissioning costs per MW.

## 5. Key Issues

### 5.1. Paying for Decommissioning in Regulated and Deregulated Regions

The costs of decommissioning power plants are typically borne by one of two stakeholders: electricity consumers or generating companies (and their shareholders). In the unlikely case that plant owners go bankrupt, costs would ultimately fall to local, state, or federal taxpayers. Absent bankruptcy, the most important issue regarding who pays for decommissioning is whether plants operate in cost-of-service regions or in competitive markets.

#### 5.1.1. Cost-of-Service Regions

In cost-of-service regions, regulated utilities typically recover the costs associated with decommissioning power plants through rates, subject to approval from regulators. In these regions, utilities prepare cost estimates for decommissioning plants on a recurring basis and, with approval of regulators, accumulate the needed funds through rate adjustments.

For example, in Florida, where regulators and utilities refer to power plant “dismantlement” rather than decommissioning (“decommissioning” is reserved for reference to nuclear plants), all generating units are required to accrue funds toward dismantlement throughout their lives. Every four years, utilities work with contractors to update estimates on dismantlement costs, including contingency costs, required to bring the site to “marketable or usable condition.” The utility recovers these costs through rates, then accrues funds by making annual payments based on the anticipated final dismantlement costs divided by the number of

years each unit is expected to continue operations.<sup>8</sup>

Since 2000 in Florida, 176 units representing over 7,000 MW of coal, petroleum, and natural gas-fired capacity (as well as one nuclear unit) have been retired. In many cases, utilities have retired petroleum plants and replaced with them more efficient NGCC units, contributing to lower emissions of CO<sub>2</sub> and other pollutants. In addition, the low cost of natural gas in recent years has contributed to a decline in retail electricity prices in Florida (as it has in many other parts of the country).

In some cases, however, this method of cost recovery for decommissioning has resulted in large unanticipated costs borne by ratepayers. For example, following a large 2008 spill from a CCR impoundment, the TVA spent over \$1 billion on cleanup (US EPA and TVA 2014), with costs recovered through rates (Flessner 2013).

In the wake of this high-profile case, legislatures in some states have taken steps to clarify or limit the types of decommissioning costs that may (and may not) be recouped through rates. For example, a 2014 North Carolina law following a large coal ash release limited the ability of utilities to recover costs associated with the cleanup of such releases.<sup>9</sup> In 2015, Nevada enacted a law that requires large utilities to develop plans for the “timely cleanup and disposal of surplus assets,” and stipulates that failure to comply will prevent utilities from recouping decommissioning costs through rates (Baker et al. 2015).

#### 5.1.2. Deregulated Regions

In deregulated regions, where electricity prices are set through competition, generating companies do not explicitly recoup

<sup>8</sup> Electric Utilities Dismantlement Studies, Section 25-6.04364, Florida Administrative Code (2016).

<sup>9</sup> Coal Ash Management Act of 2014, Session Law 2014-122, General Assembly of North Carolina (2014).

decommissioning costs through rates. Instead, costs must be planned for and incorporated as a cost of doing business. However, it is not clear whether all companies properly account for such costs.

Publicly listed companies file annual reports estimating these decommissioning costs (Section 5.1.2.1), but it is unclear whether smaller generating companies do the same. For example, this study was unable to find any evidence of planning for decommissioning costs for fossil or renewable plants operated by municipal or other smaller entities in Texas.

In recent years, low electricity prices in many regions have reduced the profitability of many generators, which may further reduce the ability of firms to properly account and plan for ultimate decommissioning of plants.

#### *5.1.2.1. Asset Retirement Obligations*

In their annual financial reports to the US Securities and Exchange Commission known as 10-Ks, publicly listed generating companies report AROs. An asset retirement obligation is defined as “an environmental remediation liability that results from the normal operation of a long-lived asset and that is associated with the retirement of that asset (e.g., the obligation to decontaminate a nuclear power plant site or cap a landfill)” (Ernst & Young 2016). Until recently, nuclear assets have constituted the bulk of ARO funds. However, increased awareness of environmental risks and new regulatory requirements have increased anticipated costs of decommissioning for other plant types. In particular, the anticipated costs of retiring CCR impoundments at coal-fired power plants have grown dramatically in recent years and are likely to affect financial obligations for plant owners.

ARO may change over time as the definition of “the normal operation of a long-lived asset” changes. In particular, certain

environmental liabilities that are now understood to be common have not always been included in reported AROs.

Issued in April 2015, EPA’s CCR rule requires firms to include the environmental remediation obligations associated with coal ash in their AROs. For example, NRG, a large independent power producer, reports in its 2015 10-K filing that it has set aside funds to manage coal combustion waste because of this rule (though it does not report the dollar total). NRG’s total AROs for 2015 are reported as \$945 million, \$643 million of which is associated with nuclear decommissioning liabilities (NRG Energy 2016).

However, AROs for some utilities may underestimate the actual costs of remediation, particularly related to CCRs. As noted in Section 4.1, Duke Energy, the nation’s largest electric power utility, reported AROs for closure of coal ash impoundments in the Carolinas at \$4.24 billion (Duke Energy Corporation 2016). In 2013, prior to a release from a CCR impoundment in North Carolina, Duke did not report any AROs specifically designated for closure and remediation of CCR facilities (Duke Energy Corporation 2013).

Because most decommissioning cost studies were carried out before the enactment of new EPA rules regarding CCRs, associated AROs are likely to increase for most utilities that own regulated impoundments. If the ARO revisions made by Duke Energy are at all representative of the future costs of safely closing CCR basins, AROs for other companies owning ash basins are likely to grow by billions of dollars.

If companies in deregulated regions are underestimating their AROs in internal and external accounting protocols, funds may not be available to adequately remediate any legacy environmental issues, and if those costs are sufficient to result in bankruptcy, they may be transferred to ratepayers or taxpayers.

Although this is unlikely to be a concern for large, well-capitalized companies, it may pose risks for smaller companies with substantial remediation and monitoring requirements associated with CCRs.

## **5.2. Local Economic and Fiscal Considerations**

Power plants are key economic assets in many communities where they operate. When plants retire and are not repowered or repurposed for other economic uses, local employment and income may be substantially affected. Although this issue arises most prominently when a plant is retired, the different options available to plant owners after retirement each have implications for communities and local economies. This section focuses on these issues.

In 2016, an estimated 94,100 people were employed in fossil-fired power plants, roughly 60 percent of the total number employed by electricity generators (US Bureau of Labor Statistics 2017). Although 95,000 is a relatively small number measured against the 140 million employees across all sectors of the economy, certain communities are heavily reliant on employment and income driven by large fossil-fired power plants.

For example, Montana's 2,100 MW coal-fired Colstrip power plant and the nearby mine that supplies it directly employ 730 people, according to press reports (Puckett 2017). Two of the plant's four units have been slated for closure by 2022, with large potential economic impacts for the city of Colstrip,

population 2,200, and the surrounding county of Rosebud, population 9,000. In response, Montana policymakers filed legislation to require that plant owners submit decommissioning plans to state environmental regulators, including plans to compensate nearby residents and local governments for negative economic and fiscal impacts (not environmental impacts), which would likely run into the tens of millions of dollars.<sup>10</sup>

The bill passed the state senate but not the house, and similar legislation may be reintroduced in future sessions. Although the legality of this legislation is uncertain, it illustrates the severity of potential economic impacts for communities heavily reliant on large power plants.

Along with broader economic impacts, the fact that power plants often make up a large share of the local tax base can mean additional local economic impacts from decommissioning. However, the valuation methods for power plants varies from state to state, resulting in a wide range of assessed values for plants.

In Texas, for example, plants are assessed using a market-based income model. This method for appraisal accounts for the current price of electricity along with fuel, operating, and capital costs to estimate annual revenues and profit. In other states, such as Florida or Pennsylvania, plants may be assessed for property tax purposes on the estimated resale value of their physical assets, including the land they occupy. As Table 10 shows, plants with similar physical characteristics may receive very different valuations depending on local assessment methods.

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<sup>10</sup> Coal-Fired Generating Unit Mitigated Retirement Act, S. 338, Montana 65th Leg. (2016).

**TABLE 10. ASSESSED VALUE OF SELECT POWER PLANTS IN 2015**

Plant name	State	Fuel	Capacity (MW)	Taxable value	Taxable value/MW
WA Parish	TX	Coal	3,675	\$865,390,820	\$235,480
Sandy Creek	TX	Coal	937	\$427,491,427	\$456,234
Monticello	TX	Coal	1,880	\$373,540,150	\$198,692
Tolk	TX	Coal	1,067	\$310,607,100	\$291,103
Turkey Point	FL	Nuclear, gas/oil	3,330	\$61,160,648	\$18,367
Fort Myers	FL	Gas/oil	2,080	\$6,188,296	\$2,975
Sanford	FL	Gas/oil	1,912	\$13,203,355	\$6,906
Hatfield's Ferry	PA	Coal	1,710	\$13,616,100	\$7,963

Sources: Texas: local appraisal districts; Florida: local assessors' offices; Pennsylvania: Greene County Department of Finance.

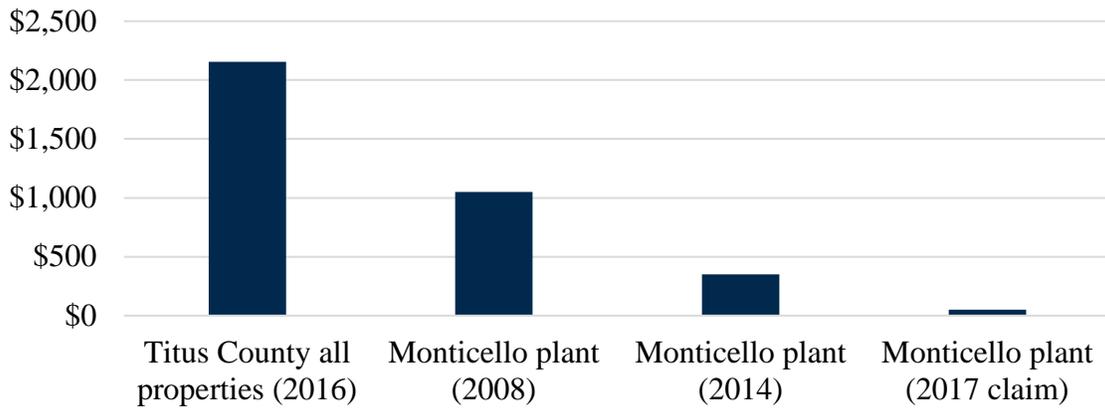
In Texas, state valuation methods appear to lead to higher assessed values than in Pennsylvania or Florida. However, this method also can result in greater volatility in valuation, as the profitability of a plant may vary widely from year to year based on prevailing electricity prices, fuel costs, and other factors. For example, one large coal-fired power plant, the Monticello plant in Titus County, Texas, has seen its valuation change from over \$1 billion in 2008 to \$350 million in 2014 (Titus County Appraisal District 2017). In 2017, the plant's owner filed suit against the county appraisal district, arguing that the plant should instead be valued at \$50 million (Carpenter 2017). For reference, the total taxable value of all properties in Titus County was roughly \$2.2 billion in 2016 (Figure 17).

In states where plants are assessed based on the estimated resale value of their capital and the land they occupy, local governments tend to see less volatility in assessed values. However, plant closure and decommissioning

can lead to unusual incentives for local governments that have become reliant on power plants to provide tax revenue.

For example, in Greene County, Pennsylvania, the recently retired Hatfield's Ferry power plant is appraised at \$14 million, accounting for roughly 1 percent of the county tax base. Because Pennsylvania property tax law assesses properties based on the resale value of equipment and land, the retirement did not affect the plant's valuation (whereas in Texas, for example, it would have had a major effect). However, if the plant were torn down or its major components sold, the valuation would drop considerably and include only the value of the remaining land and other assets. This provides an incentive, at least in theory, for local governments to delay or prevent the demolition of the plant or repurpose the property. The longer a facility sits idle, the more degraded it will become and the worse contamination issues will become, leading eventually to higher mitigation costs when the site is ultimately decommissioned.

**FIGURE 17. PROPERTY VALUATIONS IN TITUS COUNTY, TEXAS**



Source: Data from Titus County Appraisal District (2017).

Note: This figure highlights the volatility of power plant valuations in Texas and shows the importance of one particular plant to the tax base of Titus County.

**TABLE 11. LOCATION OF OLDER AND RETIRED FOSSIL FUEL POWER PLANTS, 100 MW OR LARGER**

Location	Operating, older than 40 years	Retired
Urban/suburban (inside MSA)	332 (72%)	195 (78%)
Rural (outside MSA)	118 (26%)	52 (21%)
Highly rural (>50 miles from MSA)	12 (2%)	2 (1%)
Total	462	249

Sources: Data from EIA (2016) and US Census Bureau (2016).

### 5.3. Decommissioning in Rural and Urban/Suburban Areas

Since 2000, most large plant retirements have occurred in and around urban or suburban regions. Of the 249 plants that have been retired with capacities of greater than 100 MW, 195 (78 percent) have been within a metropolitan statistical area (MSA), with 54 (22 percent) located outside MSAs. Looking forward, most large operating coal, petroleum, or natural gas-fired plants that are 40 years old or older are also found in urban or suburban regions, as illustrated in Table 11.

#### 5.3.1. Decommissioning in Urban and Suburban Areas

As decades-old power plants have retired in and around major US cities, redevelopment opportunities have emerged for plant owners and local developers. In recent years, a

number of these retired power plants have been repurposed for mixed-use development. Such facilities are often desirable for developers because of their large footprint and vast floor space, high ceilings, proximity to urban centers or waterways, sturdy construction, and unique architectural features.

##### 5.3.1.1. Federal, State, and Local Incentives

From 1997 through 2011, federal tax incentives offered full expensing of cleanup costs for redeveloping brownfields associated with any industrial facility (US EPA 2011), with annual costs in the range of \$100 million (US Joint Committee on Taxation 2008). Currently, EPA provides grants and technical assistance for local governments interested in assessing environmental damage, cleaning up sites, and providing related job training programs, with grants totaling roughly \$59 million in 2017 (US EPA 2017).

State and local governments also offer a variety of policies to encourage redevelopment of former industrial and brownfield sites. For example, the state of New York offers a refundable tax credit for redevelopment of brownfields properties worth up to \$45 million (New York State Department of Taxation and Finance 2017). Baltimore offers brownfield developers a reduction in city property tax rates (Baltimore Development Corporation 2017).

Developers may also benefit from retired power plants obtaining status as historic buildings. For example, the Delaware River Generating Station in Philadelphia, which retired in 2004, was added to the National and Philadelphia Registers of Historic Places in 2016. Certification on these registries enables redevelopers to take advantage of income tax credits offered by the federal government of up to 20 percent (US National Parks Service 2012) and, in some locations, credits against state income or local property taxes (San Francisco Planning Department 2010; Pennsylvania Dept. of Community & Economic Development 2014; New York State Dept. of Parks Recreation and Historic Preservation 2017). A variety of state and local tax and nontax incentives are described in a series of reports by Bartsch and Wells (2005, 2006a, b, c), though many provisions are likely out of date over a decade after publication.

Dozens of projects have benefited from these types of financing opportunities. One project located along the Hudson River in Yonkers, New York, would convert the Glenwood Power Station, which retired in the 1960s but was never fully decommissioned, to an “arts-focused event complex,” with expansion plans including restaurants, a 90-room hotel, and a 22-slip marina. According to news reports, the \$150 million project could benefit from up to \$45 million in state tax

credits (Hughes 2014). The developer describes the building, which it acquired in 2012, as currently undergoing restoration and redevelopment (Lela Goren Group 2017).

In Austin, Texas, a large retired power plant in the city’s downtown has been redeveloped into a mixed-use residential and commercial space, including a grocery store and hundreds of apartments. The redevelopment of the plant was enabled in part by changes in property tax treatment of the facility (City of Austin Texas 2008).

As described in a report by the American Clean Skies Foundation (2011), numerous other large-scale power plant redevelopment projects have been carried out, including in Chicago; Portland, Oregon; Providence, Rhode Island; Queens, New York; and Sacramento. Project costs have ranged from less than \$10 million for small plants to more than \$150 million for larger projects. Another report describes 25 redevelopment projects, noting that the average time between plant closure and sale was 16 years, and the average time between plant closure and the completion of redevelopment was 27 years (Delta Institute 2014). Notably, every major redevelopment project identified in these reports (and in this review) has taken place in or around a major city.

### *5.3.1.2. Challenges of Urban Redevelopment*

For project owners and contractors, decommissioning in urban areas may pose additional challenges. Although major development projects in urban areas are by no means unusual, dismantlement and demolition of power plants in dense urban areas tend to be costlier than in other locations such as an industrial park. Hazardous materials removed from the site (typically by truck) need to pass through populated areas, increasing risks and associated costs. Demolition activities also have to be more carefully managed in light of local concerns and regulations regarding noise, dust, and light.

Utilities or project developers typically have strong incentives to meet the expectations of the surrounding communities. For utilities, reputational concerns come to the fore, as these companies will continue to operate other plants and serve their customers. If new developers have assumed responsibility for the project, those developers also have an interest in being seen as good neighbors in their communities.

### 5.3.2. Decommissioning in Rural Areas

Since 2000, 52 plants greater than 100 MW have been retired outside of MSAs, and 130 plants aged 40 years or more and with capacities greater than 100 MW sit outside of MSAs (Table 11). In these rural areas, or in other locations where there is a lack of private sector interest in redeveloping a site, owners may see little financial incentive to fully decommission retired plants. Particularly in deregulated regions, where decommissioning costs are not built into the rate base, the costs of decommissioning are borne by shareholders, and the return on fully decommissioning a plant may be zero. As discussed in Section 3.4.1, this dynamic may lead some plants to go “cold and dark” for an uncertain period of time, potentially leading to issues of blight, reduced property values, crime, and other concerns.

In other cases, new economic development opportunities may arise. For example, in 2016, a 568 MW coal-fired power plant was demolished along the Ohio River in eastern Ohio, where production of liquids-rich natural gas from the Utica and Marcellus Shale plays has grown dramatically in recent years. After demolition and restoration, the property was transferred to an international company interested in constructing an ethane “cracker,” which uses ethane, a natural gas liquid, as a

feedstock in the production of ethylene, a key component of plastics and other products (First Energy 2016). Such plants often entail investments of \$4 billion or more.

#### 5.3.2.1. Federal, State, and Local Incentives

In some locations, retired plant sites may offer significant value because of their proximity to electricity transmission infrastructure. EPA administers a program known as RE-Powering America’s Land, which provides technical assistance for developers interested in building renewable energy facilities on brownfield sites. This may encourage some plant owners to fully decommission and repower their facilities. However, the bulk of these projects have occurred at landfills rather than brownfields (US EPA 2016b).

The US Department of Commerce, under its Economic Development Association, launched Partnerships for Opportunity and Workforce and Economic Revitalization, or the POWER Initiative, in 2016. This program provides funding and expertise to support local workforce development programs in communities negatively affected by declining coal production and consumption, including decommissioned coal-fired power plants (US Economic Development Association 2017).

In Pennsylvania, for example, the state Department of Community and Economic Development has partnered with the POWER Initiative to commission a series of studies to assess the economic potential for retired coal plant sites, predominantly in rural parts of the state. Because power generation companies may not have the expertise to evaluate real estate opportunities associated with retired plants, these studies are designed to highlight for owners the reuse options for their sites, which may have substantial value.

## 6. Conclusions

This report provides an overview of the key issues facing plant owners as they decide how to decommission retired power plants fueled by coal, oil, natural gas, wind, or the sun. It provides a framework for understanding key decision points, assesses the major cost drivers of decommissioning for different plant types, and identifies key issues that warrant attention from plant owners, regulators, communities, and other stakeholders. It also makes recommendations for state policymakers and regulators and provides information on decommissioning costs and other key issues that can inform the implementation of these recommendations. Conclusions and suggestions for additional research are provided below.

### 6.1. Costs of Decommissioning

- The costs of decommissioning power plants can be large, especially for coal plants managing CCRs under a new regulatory framework. In some regions, it appears that utilities and regulators have not adequately planned for these costs, which will ultimately be borne by shareholders, ratepayers, or taxpayers.
- The costs of decommissioning onshore wind and solar PV appear to be modest, but existing accounting protocols may underestimate these costs. In particular, optimistic assumptions about the salvage value of scrap steel and other equipment may lead to inadequate financial preparation.
- The costs of decommissioning offshore wind appear high relative to other fuels, but substantial uncertainty remains because of limited experience.
- The costs of decommissioning natural gas—and oil-fired power plants appear to be modest in most cases.

### 6.2. Planning and Saving for Decommissioning

- In traditionally regulated states, public utility commissions typically require plant owners to plan for decommissioning and recoup the associated costs through rates.
- In some deregulated states, notably Texas, there was a lack of evidence that state or local regulators require any planning (financial or otherwise) for decommissioning.
- Federal, state, and local programs incentivize decommissioning and redevelopment of industrial property. These programs are often beneficial for communities where they occur, but they can shift the costs of decommissioning and remediation from shareholders and ratepayers to taxpayers.

### 6.3. Community Impacts of Decommissioning

- In regions with strong demand for land, plant owners often have financial incentives to decommission and sell a property. In rural regions, financial incentives to decommission may be weaker and—unless decommissioning is planned for and funded in advance—plant sites may sit idle for years or decades, with negative environmental and community impacts.
- Decommissioning a plant can provide temporary employment opportunities in the community where a plant has operated. However, the loss of long-term employment at the plant will tend to outweigh these opportunities.
- Power plants are often an important part of the local tax base, particularly in rural communities. Decommissioning a power plant can have a major impact on revenues for school districts, counties, and other local governments.

#### **6.4. Suggestions for Future Research**

This report raises numerous questions that warrant further investigation, the answers to which will be important to utilities, regulators, and communities as they plan for decommissioning hundreds of power plants in the coming years. These questions include the following:

- What are the potential costs to plant owners of complying with EPA's coal ash rule, particularly with regard to long-term monitoring and remediation?
- What are the social costs (such as environmental contamination or blight) of a plant sitting idle for years or decades in urban and rural settings?
- Across all 50 states, what policies are currently in place with regard to planning and saving for power plant decommissioning?
- Are landowner lease agreements sufficient to provide for timely and thorough decommissioning of wind and solar facilities?

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